BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures.	))))	Case No. 09-512-GE-UNC

FINDING AND ORDER

The Commission finds:

(1) Ohio Power Company; Columbus Southern Power Company; Duke Energy of Ohio, Inc.; the Dayton Power and Light Company; the Toledo Edison Company; Ohio Edison Company; and the Cleveland Electric Illuminating Company (collectively, electric utilities) are public utilities, as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction and general supervision of the Commission, in accordance with Sections 4905.04, 4905.05, and 4905.06, Revised Code.

(2) Columbia Gas of Ohio, Inc.; the East Ohio Gas Company d/b/a Dominion East Ohio; Vectren Energy Delivery of Ohio, Inc.; and Duke Energy of Ohio, Inc., (collectively, gas utilities) are public utilities, as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction and general supervision of the Commission, in accordance with Sections 4905.04, 4905.05, and 4905.06, Revised Code.

(3) On June 24, 2009, the Commission issued an entry in this proceeding, establishing a procedure for the development of protocols for the measurement and verification (M&V) of energy efficiency and peak demand reduction measures (June 24 Entry). In Appendix A of the entry, the Commission identified five major issues where policy guidance was needed in order to proceed with the development of an Ohio Technical Reference Manual (TRM) and the determination of energy savings and demand reductions. In Appendix B, the Commission provided categories of data that should be included in a TRM for deemed measures and deemed calculated measures for determining energy savings, demand reductions, and cost-effectiveness per the total resource cost (TRC) test. The

Commission provided interested parties an opportunity to submit comments on the information set forth in Appendices A and B. In a subsequent entry issued on July 14, 2009, the legal director granted, in part, the gas utilities' motion for an extension to file comments regarding the filing of lists and proposed measures, as well as proposed values and protocols. That entry also established an alternative procedural schedule for the gas utilities.

(4) On July 24, 2009, the following entities filed comments on Appendix A: Industrial Energy Users-Ohio (IEU-Ohio); Toledo Edison Company, Ohio Edison Company, and The Cleveland Electric Illuminating Company (collectively, FirstEnergy); Ohio Power Company and Columbus Southern Power Company (collectively, AEP-Ohio); Ohio Manufacturers Association (OMA); Ohio Hospitals Association (OHA); Duke Energy of Ohio, Inc. (Duke); Dayton Power and Light Company (DP&L); Ohio Partners for Affordable Energy (OPAE); and the Office of the Ohio Consumers' Counsel, the Natural Resources Defense Council, Citizens Power, the Ohio Environmental Council, Environment Ohio, and Sierra Club (collectively, OCEA). This entry addresses comments and recommendations regarding Appendix A. Pursuant to the June 24 Entry, thec omments filed regarding Appendix B have been reviewed by Staff and, as appropriate, have been incorporated into a modified Appendix B. Modified Appendix B was recently posted on the Commission's website, and is available for use.

(5) On July 8, 2009, Staff hosted a workshop to provide stakeholders with a common background of evaluation, monitoring, and verification (M&V) approaches and issues in order to facilitate a discussion, among stakeholders, of an Ohio approach to M&V that will ultimately be embodied in the TRM. On August 5, 2009, Staff hosted a second workshop to discuss Total Resource Cost (TRC) test issues as they relate to the development of the TRM.

(6) Similar to the underlying policy considerations and provisional recommendations identified in Appendix A and issued for comment, the Commission has identified and described policy questions arising from the implementation of the TRC test in Ohio and proposed provisional *policy recommendations* for the

manner in which those questions should be resolved in the context of the development of the TRM. These policy questions and series of recommendations are attached as Appendix C. Interested persons who wish to comment on these potential policy determinations, or suggest other policy considerations with regard to Ohio's implementation of the TRC test, may file comments in this docket no later than November 10, 2009. Such comments should indicate interested persons' perspectives on the issues identified in Appendix C and should identify and comment on other policy considerations that should be addressed which relate specifically to implementation of the TRC test in Ohio.

(7) On September 3, 2009, the electric utilities filed a joint motion for expedited consideration and a 30-day extension of time to file the actual proposed predetermined values and proposed protocols required by the Commission's June 24 Entry. The Commission granted the electric utilities' joint motion on September 10, 2009. On September 17, 2009, the gas utilities filed a second motion for expedited consideration and an extension of the deadline for the filing of proposed values and protocols from October 15, 2009, until November 15, 2009. In their motion, the gas utilities explain that they are reviewing the values and protocols developed by other states, as suggested by the Commission, and that it will take additional time to develop comments, values, and protocols for the Commission's consideration. In support of their motion, the gas utilities also cite the fact that they filed approximately 235 current and proposed gas measures on September 8, 2009, and despite their best efforts, they will not be able to file values and protocols for 235 gas measures by October 15, 2009. Finally, the motion states that all other parties to the proceeding were contacted with respect to the motion, and only one party, OPAE, objected to the motion, but decided not to file a memorandum contra. Despite OPAE's objection to the gas utilities' motion, it does not object to expedited consideration of the motion.

(8) The Commission is cognizant of the expedited nature of this proceeding, but believes that an extension here is warranted based upon the circumstances surrounding the gas utilities' efforts to file values and protocols. To this end, given that the delay in the filing of the gas utilities' proposed values and

protocols will likely improve the consensus document and will not adversely affect the overall process, the Commission finds that good cause exists to support the motion. Therefore, the gas utilities' motion is granted.

Appendix A

Issue 1: Should the Commission evaluate performance of utility programs on the basis of achieved gross or net savings, or both?

(9) The provisional recommendation for Issue 1 proposed evaluating the performance of utility programs on the basis of gross savings,[1] consistent with the TRC test. The provisional recommendation also suggested moving to a net savings[2] calculation as utilities gain energy efficiency program experience.

(10) IEU-Ohio asserts that SB 221 requires the effects of all demand-response, energy efficiency, and peak demand reduction programs for mercantile customers, adjusted upward by the appropriate loss factors, be counted when measuring compliance with a utility's performance requirements. Therefore, IEU-Ohio contends that it is not necessary and not lawful to estimate net savings.

(11) FirstEnergy, AEP-Ohio, Duke, and DP&L agree with the provisional recommendation of utilizing gross savings, but further argue that the utility energy efficiency programs also should be evaluated with the gross savings calculation methodology in the future. FirstEnergy adds that net savings calculations often involve detailed survey sampling, which adds cost. Duke cautions the Commission that if it decides to move to a net savings approach, care must be taken that utilities are not adversely impacted with respect to meeting benchmark energy efficiency requirements.

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[1] Gross savings calculations attempt to measure the change in energy consumption that results directly from program-related actions taken by consumers, regardless of the extent that their behavior is actually influenced by the program. Gross savings calculations measure the physical change in energy use after taking into account factors beyond the control of the customer or sponsor.

[2] Net savings calculations attempt to measure the change in energy use directly attributable to program-related actions, taking into account free-riders and spill-over (see n.3 and 4).

(12) OMA and OHA likewise endorse the continued use of gross savings calculations. OMA and OHA base their position, in part, on the contention that net savings calculations are administratively complex and expensive.

(13) OPAE also supports the provisional recommendation, explaining that, at this point in time, spill-over effects[3] and free-riders[4] are not critical issues, but that changing Ohioans' approach to using energy is critical at this juncture.

(14) Conversely, OCEA argues that gross savings calculations do not appropriately adjust for free-riders, and will lead to increased payments for utility consumers. OCEA posits that the Commission should require utilities to use the net savings calculations.

(15) The gas utilities argue that since SB 221 does not mandate the implementation of gas energy efficiency programs, they should be free to suggest either a net or gross savings calculations methodology as part of an application seeking approval of a gas energy efficiency program, if such an application is required.

(16) Most commenters agree with the provisional recommendation to evaluate program performance on the basis of gross savings initially. Therefore, the Commission finds that the gross savings methodology will be employed to evaluate program success initially. There may, however, be some instances, in which the Commission may specify the use of net savings as a condition of program approval. For example, where an energy efficiency program is implemented by a utility, and customers have already taken the steps promoted by the program, the net savings methodology may be more appropriate. The use of the net savings approach in these situations will work to ensure that utilities are only recovering revenues for actual losses. For various reasons, a number of commenters take issue with the second part of the provisional recommendation, which recommends moving toward net energy savings calculations at some point in the future. While the added value of collecting

3 Spill-over effects refer to the program-related actions of those individuals who are not active energy efficiency program participants.

4 Free-riders are program participants who would have invested in energy efficiency absent an energy efficiency program.

and using the information necessary to calculate net savings may be outweighed by the added administrative burden and cost of doing so at this time, it may not be in the future. Therefore, the Commission intends to address the issue of moving toward program evaluation on a net savings basis as experience with energy efficiency program implementation and evaluation is gained. Additionally, the Commission finds that, in order to minimize the potential for free-riders and some of the need to calculate net savings, utilities should not provide incentives for programs that have a payback of one year or less.

(17) While the Commission recognizes that there is no statutory requirement in SB 221 to implement gas energy efficiency programs, the Commission believes that administrative costs can be reduced, better economies of scale can be realized, and energy efficiency will potentially increase if electric and gas utilities use the same energy savings calculation methodologies. The Commission, therefore, encourages the gas utilities to use the technical reference manual (TRM) in energy efficiency program development, and, except where otherwise directed by the Commission, to use gross savings calculations when evaluating program effectiveness. As with electric energy efficiency program savings calculations, the Commission intends to leave open the possibility of evaluating gas energy efficiency programs based on net savings in the future.

Issue 2: How should the Commission define baseline efficiency and market penetration for determining energy savings and demand reductions?

(18) The provisional recommendation for Issue 2 established the baseline used for calculating energy savings as the minimum efficiency requirements of federal or state minimum efficiency standards, or current market practices, whichever is higher. For early retirement of appliances/equipment (equipment), the recommendation proposed using the difference between the energy use of the existing equipment and the newer, high efficiency equipment until the useful life of the existing equipment would have expired. Subsequently, the energy savings would be calculated as the difference between the energy use of the high efficiency equipment and new standard equipment.

(19) OCEA and Duke generally support the provisional recommendation for defining baseline efficiency. However, Duke highlights the difficulty in determining "current market practice," and asserts that the best practice would be setting baselines using established government standards, as such a practice will remove unnecessary ambiguity. OCEA notes that when considering baseline estimates in the event of the early retirement of equipment due to utility demand side management programs, the exact age of the equipment should be obtained, verified, and recorded.

(20) OPAE also supports the use of federal or state minimum efficiency standards as the baseline for determining the effect of installing efficiency measures; however, similar to Duke, OPAE does not support the decision to use current market practices at this point. Additionally, in the event that no established code or standard exists, OPAE recommends using the actual savings against the actual baseline.

(21) AEP-Ohio supports the use of federal or state minimum efficiency standards for establishing the baseline, but believes that the baseline should initially be set at the federal or state minimum efficiency standards applicable in Ohio in 2009. AEP-Ohio further argues that energy efficiency achievements that count toward utilities' benchmarks should include changes in consumption that are attributable to future codes and standards.

(22) Like AEP-Ohio, FirstEnergy asserts that the baseline should be based on assumptions that most closely reflect conditions at the time a program is implemented. FirstEnergy further contends that the baseline should not be determined by the use of a hypothetical industry or market standard.

(23) IEU-Ohio contends that Section 4928.66(A)(2)(c), Revised Code, requires the Commission to count the effects of all mercantile demand-response and energy efficiency programs. IEU-Ohio asserts that SB 221 does not permit the Commission to make the results of certain types of activities that produce energy efficiency or peak demand reductions ineligible for compliance with the portfolio requirements by raising the baseline for determining savings as suggested in the provisional

recommendation. Therefore, IEU-Ohio strongly urges the Commission to calculate the baseline using the as-found methodology.[5] IEU-Ohio expresses concern that any method other than the as-found method will increase the cost of compliance with the portfolio requirements. OMA and OHA echo IEU-Ohio's concerns.

(24) DP&L argues that in order to minimize the administrative burden placed on the utilities, the Commission should initially adopt an as-found methodology for existing equipment and early replacement programs, and leave open the possibility of revisiting the issue later. DP&L further contends that federal and state minimum efficiency standards should be used for calculating the baseline for new construction or replacement of equipment upon failure.

(25) The gas utilities suggest that the Commission should determine the appropriate baseline on a case-by-case basis. The gas utilities agree, however, that the baseline for early retirement programs should be based on the energy use of the existing equipment, until the equipment would have been retired under normal conditions. The gas utilities urge the Commission to note that the remaining useful life actually increases as equipment ages.

(26) Although several commenters urge the Commission to establish the baseline for energy efficiency calculations using the as-found methodology, this method could potentially overstate the energy savings effects of efficiency programs. Additionally, when new equipment is installed as a result of new construction, normal replacement schedules, or the failure of existing equipment, the as-found methodology could potentially allow utilities to claim savings for changes in energy use that are unrelated to any effects of efficiency programs. In those circumstances, the installed equipment must meet federal or state minimum efficiency standards, so simply installing such equipment could not be the result of or attributable to an electric utility's or mercantile customer's program, or a program at a mercantile customer's site.

[5] Under the "as-found" method, savings are calculated by subtracting the energy efficiency of existing equipment from the proposed new, more efficient equipment.

(27) For programs involving the early retirement of existing equipment, using the federal or state minimum efficiency standards or then-current market practices to set a baseline for measuring savings could understate the initial energy savings of such programs. In such cases, the difference between the energy used by existing equipment and the replacement equipment, which may meet federal or state minimum efficiency standards, would not count. Therefore, the Commission finds that for purposes of calculating compliance with statutory benchmarks for programs other than those targeting early retirement of functioning equipment, the baseline should be set at the higher of federal or state minimum efficiency standards, or, if data is readily available for the measures at issue on the Department of Energy's Energy Information Administrator (DOE EIA) website[6], efficiency levels for current market practices for those measures. For purposes of calculating energy savings for programs targeting early equipment retirement, the Commission finds that the as-found method should be used until the remaining useful life of the existing equipment would have expired. Subsequent to the expiration of the existing equipment's useful life, the baseline should be calculated at the higher of federal or state minimum efficiency standards, or, if data is readily available on the DOE EIA website, efficiency levels for current market practices for that equipment.

Issue 3: Should reported energy savings and demand reduction use retroactive or prospective TRM values?

(28) The provisional recommendation for Issue 3 proposed that estimates for cost, energy, and demand savings be based on the best information available at the time the estimates or calculations are derived. The provisional recommendation explained that, if cost, energy, and demand savings estimates for energy efficiency measures that are compiled after a measure is implemented (ex post) vary from the previous year's figures, which were estimated before the measure was implemented (ex ante), the ex post estimates should be used for future measure installations and programs. However, the provisional recommendation proposed that deemed and

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6 www.eia.doe.gov

deemed calculated cost and energy savings[7] would not be adjusted retroactively for previously installed measures. Additionally, the provisional recommendation proposed that savings from custom projects or programs, which are determined ex post using agreed-upon protocols, should use the ex post values as the credited savings. The provisional recommendation did not provide a recommendation as to whether ex post or ex ante estimates should be used for the remaining useful life of the current year's investment.

(29) Several commenters, including Duke, IEU-Ohio, OPAE, OMA, OHA, and the gas utilities, agree with the provisional recommendation that ex post energy savings and demand reductions should be applied prospectively. DP&L, OCEA, and AEP-Ohio generally support the recommendation, but DP&L urges the Commission to avoid applying ex post estimates to the remaining life of program measures. OCEA believes that ex post values should be used to calculate remaining future savings and cost estimates of program investments made in the current year, and AEP-Ohio suggests that protocols should be updated periodically based on evaluation results and available data, and then applied prospectively for future program years.

(30) FirstEnergy argues that revisions to the TRM should be made on a prospective basis only. FirstEnergy, however, urges the Commission to estimate costs and savings at the time of measure installation or program implementation, or ex ante. FirstEnergy argues that this process will provide certainty and minimize program costs by eliminating duplicative M&V tasks.

(31) Based upon the comments provided, the Commission finds that the provisional recommendations should be adopted for purposes of determining compliance with efficiency standards. However, upon further consideration, we find that any recovery of lost revenues associated with the implementation of programs to comply with energy efficiency and peak demand reduction benchmarks should be trued-up based on ex post calculations of savings.

[7] The energy savings that result from a given measure are considered "deemed" when the Commission agrees to certain per unit savings values before the measure is implemented. The same is true for energy savings that result from "deemed calculated" measures, except that the Commission also agrees to adjust the predetermined savings to reflect site-specific conditions.

(32) In determining the reasonableness of program cost recovery and compliance with energy efficiency and peak demand reduction benchmarks, estimates for cost, energy, and demand savings are to be based on the best information available at the time the estimates or calculations are derived, (i.e., ex ante). If ex post cost and energy savings estimates for efficiency measures vary from the previous year's ex ante estimates, ex post estimates should be used for future programs, installations, and investments. For compliance purposes, deemed and deemed calculated cost and energy savings are not to be adjusted retroactively for program investments made during the current year. As reflected in the provisional recommendation, custom projects or programs, where savings are to be determined ex post using agreed-upon protocols, should use these ex post values as the credited savings. As for the question of whether ex post or ex ante estimates should be used for the remaining useful life of a measure installed in the current and prior year, the Commission finds that, for compliance purposes and in order to provide certainty and predictability, as well as to simplify the administrative burden for the utilities, stakeholders, and the Commission, ex ante estimates should be used for the life of the investment.

(33) In making a lost revenue adjustment, lost distribution sales will be adjusted ex post based upon program evaluations. Implicit in this practice is the idea that it would be inappropriate for a utility to either recover lost revenues to the extent anticipated savings did not occur, or face additional lost revenue if a program produced greater savings than anticipated.

(34) In accordance with our findings on Issue 3, Staff is directed, by July 15, 2010, and annually thereafter, to update the TRM to reflect changes in cost, energy, and demand savings estimates submitted by the utilities as part of their annual compliance filing. The Commission expects utilities to use the updated TRM in planning for the subsequent calendar year program.

Issue 4: Should the cost-effectiveness test be applied at the measure, project, program, or portfolio level?

(35) The provisional recommendation for Issue 4 suggested that, in conjunction with Rule 4901:1-39-04(B), Ohio Administrative

Code (O.A.C.), the cost-effectiveness test should be applied at the portfolio level. The provisional recommendation noted that, while every measure may not pass the cost-effectiveness test, it is expected that most programs will. For programs that do not pass the cost-effectiveness test, the recommendation states that the utility should be required to demonstrate that such programs achieve significant non-energy benefits.

(36) Several commenters, including DP&L, IEU-Ohio, OMA, OHA, and the gas utilities, support the provisional recommendation. They explain that the application of the cost-effectiveness test at the portfolio level will help to ensure programmatic flexibility. OCEA also supports the recommendation, and suggests that measures, programs, and portfolio cost effectiveness be reported in annual utility filings. Additionally, OPAE generally supports the provisional recommendation, but would include "reduction in customer arrearages" and "improved payment behavior" as rationale for offering non-cost effective measures.

(37) AEP-Ohio agrees with the provisional recommendation to apply the cost-effectiveness test at the portfolio level, and contends that all programs, projects, and portfolios should be subjected to the TRC test screening process. Nonetheless, AEP-Ohio argues that failing one measure of the TRC test should not preclude a utility's inclusion of a program if the program has significant societal benefits.

(38) Similarly, FirstEnergy supports the application of the the cost effectiveness test at the portfolio level, but expresses concerns about being forced to implement programs that provide non-energy benefits without passing the cost-effectiveness test.

(39) While Duke believes that the provisional recommendation is unclear, Duke agrees that the test should be applied at the portfolio level to permit utilities greater flexibility in pursuit of energy efficiency.

(40) The Commission agrees with the commenters and adopts the provisional recommendation, concluding that the TRC test should be applied at the portfolio level. We believe that this will provide program flexibility and enable utilities to

implement programs that demonstrate non-energy benefits, regardless of whether the program is cost-effective. Along this line, the Commission also concurs with OPAE that "reduction in customer arrearages" and "improved payment behavior" should be added to the list of rationale justifying the inclusion of non-cost effective measures in the utilities' programs. Accordingly, justification for inclusion of non-cost effective measures will be expanded to include all of the following: broadening program participation/market penetration; increasing persistence of savings; enhancing system reliability; reducing per unit marketing and/or administrative cost; reducing measure cost (i.e., program has market transformation goal); supporting an emerging technology or practice; reducing greenhouse gas and regulated air emissions, water consumption, and use of natural resources to the extent not fully reflected in cost savings; advancing any of the state policies enumerated in Section 4928.02, Revised Code; reducing customer arrearages; and improving payment behavior. We wish to clarify, however, that it is not our intent to mandate the utilities to invest in programs that provide non-energy benefits. Rather, we wish to afford the utilities the opportunity to do so as they deem appropriate.

Issue 5: What expectations should the Commission establish for energy savings and demand reduction determination certainty?

(41) The provisional recommendation for Issue 5 proposed that, for systematic errors, the utilities and independent program evaluators be required to use "best practices" to establish quality assurance and quality control procedures that include field inspections and full documentation analyses. For random errors, the recommendation suggested that the utilities and independent program evaluators be required to perform evaluation sampling at a 90 percent confidence interval, with a 10 percent precision level (90/10 standard).

(42) Duke argues that the provisional recommendation is reasonable, and suggests that the International Performance Measurement and Verification Protocol should be relied upon for establishing "best practices." OPAE, OMA, and OHA also support the provisional recommendation.

(43) DP&L does not object to the use of "best practices" as a standard, with the understanding that cost remains an element of the standard. DP&L cautions, however, against the use of the 90/10 standard, as it contends that the standard is a sampling methodology only.

(44) Similarly, FirstEnergy does not object to the provisional recommendation, but urges the Commission to balance the certainty of information with the cost of obtaining that information.

(45) The gas utilities argue that the 90/10 standard makes sense only if sampling is required. They note that sampling can be expensive and is not always necessary to verify the savings of energy efficiency programs. AEP-Ohio indicates its preference for using the 90/10 standard at the program level only.

(46) IEU-Ohio argues that Ohio does not have sufficient experience with these issues to properly set expectations for energy savings and demand reduction determination certainty, and urges the Commission to gain experience before establishing sampling requirements. IEU-Ohio's concerns duplicate those of many others, who also argue that the goal of demonstrating actual savings must be balanced against incurring excessive administration costs.

(47) OCEA supports the use of the 90/10 standard by independent program evaluators, noting that the 90/10 standard is used by PJM for energy efficiency projects bidding into their RPM capacity market.

(48) Based upon the general agreement with the provisional recommendation to use best practices when establishing quality assurance and quality control procedures, the Commission finds that best practices should be used in establishing these procedures. The commenters express some disagreement, however, on whether the Commission should expect a 90/10 confidence interval for addressing random errors. The Commission believes that using the 90/10 standard is common practice, and, therefore, we will presume that surveys meeting

> the 90/10 accuracy standard also meet the best practices standard.

It is, therefore,

ORDERED, That the electric and gas utilities observe the requirements and the Commission's determinations set forth in this entry. It is, further,

ORDERED, That interested persons file comments on Appendix C no later than November 10, 2009. It is, further,

ORDERED, That the gas utilities' motion for expedited consideration and an extension of the deadline for the filing of proposed values and protocols from October 15, 2009, until November 15, 2009 be granted. It is, further,

ORDERED, That a copy of this finding and order be served upon all parties of record in Case Nos. 09-512-GE-UNC and 08-888-EL-ORD.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber

Alan R. Schriber, Chairman

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Appendix C
Policy Issues Regarding Cost and Avoided Cost for the Total Resource Cost Test in Ohio Electricity Programs

I. Background

S.B. 221 states that beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings and peak **demand** savings to meet prescribed savings requirements. The savings requirement for energy is to reduce total electricity sales by 0.3% in the first year (2009). The savings requirement increases each year thereafter, with a final cumulative energy savings of 22% by 2025. The savings requirement for peak demand is a 1% reduction in peak demand in the first year of implementation (2009) and an additional 0.75% reduction annually thereafter until 2018. The baseline for savings will be calculated using the average of the electricity sold in the three previous calendar years, unless the Public Utilities Commission Ohio (Commission) decides to amend the baseline based on growth in the region.

In response to this increased emphasis on energy efficiency measures, the Commission is developing methodologies and guidelines to clarify how distribution utilities should evaluate energy efficiency programs in Ohio. There are widely utilized approaches for evaluating energy efficiency cost-effectiveness. These are described in "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers," a publication of the National Action Plan (2008) which was produced by Energy and Environmental Economics, Inc. and Regulatory Assistance Project. The full text of this document is available at www.epa.gov/eeactionplan. However, these approaches are not necessarily tailored to Ohio, the requirements of S.B. 221, and furthermore they generally do not provide the details necessary to coordinate the development of total resource costs test (TRC) across the Ohio utilities.

As part of this process, the Commission held a workshop on energy efficiency cost-effectiveness for Ohio on August 5th, 2009, to discuss alternatives for the evaluation of cost-effectiveness. This workshop was possible as a result of the generous support provided to the Commission by the United States Department of Energy through the Lawrence Berkeley National Laboratory's technical assistance project to states on energy efficiency.

The goal of this document is to solicit comments from stakeholders in order for the Commission to define as clearly as possible an expedient approach for all of the Ohio electric utilities to compute energy efficiency cost-effectiveness using a standard approach. This document draws from the discussion at the August 5th workshop, as well as approaches used in other states. This appendix is structured as a series of provisional recommendations, and while options are described for many of the choices suggested in this appendix, a clear choice is presented for comment and discussion. The intent of the provisional recommendations is to solicit comments by interested stakeholders on these choices and the Commission invites comments and/or suggestions for alternative choices, together with supportive reasoning. The Commission will review submitted comments in order to develop and adopt a common framework for evaluation of the cost-effectiveness of energy efficiency for Ohio electricity programs. In adopting this approach, the Commission intends to provide **the following:** (a) faster development and review of proposed utility plans;; (b) less regulatory uncertainty on cost-effectiveness provisions in S.B.

221;; (c) comparability between utilities' results;; and (d) transparency for stakeholders and the public.

II. Cost Effectiveness Evaluation

a. Primary Cost–Effectiveness Test: Total Resource Cost Test

As this Commission has found in [entry adopting Green Rules in 08-888] and in [Appendix A entry in 09-512] a utility's energy efficiency and peak demand reduction portfolio must pass the TRC test. The formulation of the TRC test is the ratio of the lifecycle benefits of the portfolio over the lifecycle incremental costs. A portfolio passes the TRC test when it has a benefit/cost ratio of greater than 1.0. Additionally, utilities must provide the TRC test results for all programs and measures inside of the portfolio. The programs and/or measures, however, may be approvable even if they do not pass the TRC test (i.e. have a benefit/cost ratio of less than 1.0), if the utility can demonstrate that the programs and/or measures will provide previously enumerated non-energy benefits. Nothing in this Appendix is intended to alter, modify, or amend the Commission's prior findings with regard to the TRC test. The TRC test may be expressed as follows:

TRC Net Lifecycle Value = Portfolio Benefits – Portfolio TRC Costs

Portfolio Benefits = $\Sigma_{Measures}$ NPV TRC Avoided Cost$_{Measure}$

NPV TRC Avoided Cost$_{Measure}$ =

NPV$_{YR=1\ to\ EUL}$\{Σ_{TOU}(Energy Savings$_{TOU,YR}$ * Avoided Energy Cost$_{TOU,YR}$)\} +

NPV$_{YR=1\ to\ EUL}$\{Σ_{SEASON}(Capacity Savings$_{SEASON,YR}$ * Avoided Capacity Cost$_{SEASON,YR}$)\}

NPV$_{YR=1\ to\ EUL}$\{Natural Gas Savings$_{YR}$ * Natural Gas Avoided Cost$_{YR}$\}

Portfolio TRC Costs = $\Sigma_{Measures}$(NPV Incremental Measure Cost$_{Measure}$) + Administration Costs

NPV Incremental Measure Cost$_{Measure}$ =

NPV$_{YR=1\ to\ Program\ Cycle}$ (Incremental Measure Cost$_{Measure,YR}$ * # Installations$_{YR}$)

Where:

NPV$_{Period}$ is Net Present Value at the determined discount rate over the period indicated, either the EUL (Expected Useful Life) of a measure or the Program Cycle for this planning period. The other inputs including Energy Savings, Capacity Savings, Incremental Measure Cost, Administration Costs, Avoided Energy, and Avoided Capacity Cost which are all described in this document.

b. Should the Commission Consider Secondary Cost–Effectiveness Tests in addition to the TRC?

The TRC test answers the question whether energy efficiency is more cost-effective overall than supplying energy. It does not, however, provide any information regarding whether the portfolio, program, or measure is cost-effective from the perspective of an individual program participant, the sponsoring utility, or rate-payers who are not participating in the program. Having additional information on the program level regarding the impact of a program on its participants, non-participants, and the sponsoring utility would enable the Commission to determine whether programs are optimally designed and balanced. Secondary cost effectiveness tests could provide this additional insight.

The utility cost test,–(also known as the program administrator cost test) (UCT/PAC), the ratepayer impact measure test (RIM), and the participant cost test (PCT) are potential candidates to serve as secondary cost tests. These tests would provide more information on the distributional benefits and design of the energy efficiency programs and portfolios. Each of the distributional tests and the information it provides is discussed below.

UCT/PAC test. This test compares the change in utility revenue requirement (and average customer bills) for energy efficiency versus supply side resource procurement. Rather than the total incremental measure cost of the efficiency measure, the costs used are the utility incentives and program administration costs. The avoided costs are similar (though not necessarily identical) to the TRC test. With the reported UCT/PAC results, stakeholders will be able to evaluate the size of the incentives relative to the resource value of the measures. This is valuable information since the TRC test does not include utility incentives. In order to calculate this, the utility would need to know its costs for the program incentives. The UCT/PAC test may be expressed as follows:

UCT/PAC Net Lifecycle Value = Ratepayer Benefits – Portfolio Ratepayer Costs

Ratepayer Benefits = $\Sigma_{Measures}$ NPV Utility Avoided $Cost_{Measure}$

NPV Utility Avoided $Cost_{Measure}$ =

$NPV_{YR=1\ to\ EUL}\{\Sigma_{TOU}(\text{Energy Savings}_{TOU,YR} * \text{Avoided Energy Cost}_{TOU,YR})\}$ +

$NPV_{YR=1\ to\ EUL}\{\Sigma_{SEASON}(\text{Capacity Savings}_{SEASON,YR} * \text{Avoided Capacity Cost}_{SEASON,YR})\}$

Portfolio Ratepayer Costs = $\Sigma_{Measures}$(NPV Utility Incentive $Cost_{Measure}$) + Administration Costs

NPV Utility Incentive $Cost_{Measure}$ =

$NPV_{YR=1\ to\ Program\ Cycle}$ (Utility Incentive $Cost_{Measure,YR}$ • # $Installations_{YR}$)

Where:

NPV_{Period} is Net Present Value at the determined discount rate over the period indicated, either the EUL (Expected Useful Life) of a measure or the Program Cycle for this planning period. The other inputs including Energy Savings, Capacity Savings, Utility Incentive

Cost, Administration Costs, Avoided Energy, and Avoided Capacity Cost are all specified in this document.

RIM test. This test evaluates the impact of the energy efficiency program on all rate-payers through an assessment of the change in utility rates. Most programs around the country have been shown to have negative RIM test results (Benefit / Cost ratio < 1.0). While retail rates can go up, average bills (as measured by the UCT/PAC) can go down since overall consumption is lower. In addition to the incentives required for the UCT/PAC, the evaluation of RIM test requires an estimate of the change in customer bills and therefore a retail rate forecast to calculate. The RIM test may be expressed as follows:

RIM Net Lifecycle Value = RIM Benefits – RIM Costs

RIM Benefits = $\Sigma_{Measures}$ **NPV Utility Avoided Cost**$_{Measure}$

NPV Utility Avoided Cost$_{Measure}$ =

$NPV_{YR=1\ to\ EUL}\{\Sigma_{TOU}(\text{Energy Savings}_{TOU,YR} * \text{Avoided Energy Cost}_{TOU,YR})\}$ +

$NPV_{YR=1\ to\ EUL}\{\Sigma_{SEASON}(\text{Capacity Savings}_{SEASON,YR} * \text{Avoided Capacity Cost}_{SEASON,YR})\}$

RIM Costs = $\Sigma_{Measures}$(**NPV Utility Incentive Cost**$_{Measure}$) + (**NPV Bill Savings**$_{Measure}$) + **Administration Costs**

NPV Utility Incentive Cost$_{Measure}$ =

$NPV_{YR=1\ to\ Program\ Cycle}(\text{Utility Incentive Cost}_{Measure,YR} * \#\ \text{Installations}_{YR})$

$(\text{NPV Bill Savings}_{Measure}) = NPV_{YR=1\ to\ Program\ Cycle}(\text{Bill Savings}_{Measure,YR})$

Where:

NPV_{Period} is Net Present Value at the determined discount rate over the period indicated, either the EUL (Expected Useful Life) of a measure or the Program Cycle for this planning period. The other inputs including Energy Savings, Capacity Savings, Utility Incentive Cost, Bill Savings, Administration Costs, Avoided Energy, and Avoided Capacity Cost are all specified in this document.

PCT test. This test measures the impact of energy efficiency to the participating customers. Evaluating this test requires an assessment of the customer out-of-pocket costs relative to their bill savings. The PCT test may be expressed as follows:

Participant Test Net Lifecycle Value = Participant Benefits – Participant Costs

Participant Benefits = $\Sigma_{Measures}$ (NPV Bill Savings$_{Measure}$)

(NPV Bill Savings$_{Measure}$) = NPV$_{YR=1\ to\ EUL}$ (Bill Savings$_{Measure,YR}$)

Participant Costs = Net Present Value of Customer Cost of Measure

Can be approximated using:

Participant Costs = $\Sigma_{Measures}$(NPV Incremental Measure Cost$_{Measure}$) - (NPV Utility Incentive Cost$_{Measure}$)

NPV Incremental Measure Cost$_{Measure}$ =

NPV$_{YR=1\ to\ Program\ Cycle}$ (Incremental Measure Cost$_{Measure,YR}$ • # Installations $_{YR}$)

NPV Utility Incentive Cost$_{Measure}$ =

NPV$_{YR=1\ to\ Program\ Cycle}$ (Utility Incentive Cost$_{Measure,YR}$ • # Installations $_{YR}$)

Where:

NPV$_{Period}$ is Net Present Value at the determined discount rate over the period indicated, either the EUL (Expected Useful Life) of a measure or the Program Cycle for this planning period. The other inputs including Incremental Measure Cost, Utility Incentive Cost, and Bill Savings are all specified in this document.

The Commission is aware of and sensitive to the start-up challenges of statewide efficiency programs and does not want to create overly burdensome reporting requirements in the early stages of program development. It has been Staff's experience, however, that most, if not all, of Ohio's electric utilities conduct all three of the potential secondary cost tests as a matter of course during portfolio planning and analysis.

Provisional Recommendation #1: For informational purposes to assist in assessing the balance of the portfolio and to inform design of individual programs, the Commission will require electric ~~utility's~~ **utilities** to submit program level results for the UCT/PAC, RIM, and PCT tests to supplement the TRC test. It is not the Commission's intention, however, to require a demonstration of cost-effectiveness for any secondary test.

III. Cost Inputs to Calculations

a. Discount Rate

A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption. As each of the tests portrays a specific viewpoint, each of those perspectives comes with its own discount rate. There are a number of possible choices of discount rate to apply to compute the net present value (NPV) of the future avoided costs attributable to energy efficiency. Depending on the cost test, certain discount rates have become standard industry practice. For the TRC, UCT/PAC, and RIM tests, the after-tax weighted average cost of capital has generally been adopted because this is the same discount rate as is used from a utility perspective to evaluate supply-side investments. For the PAC test, the participant's cost of capital is often used. The Commission is interested in ~~commenters to offer~~ suggestions for proxies for participant costs for both residential and commercial/industrial customers.

> *Provisional Recommendation #2a*: When performing the TRC, UCT/PAC, or RIM test, utilities shall input the after-tax weighted average cost of capital (WACC). The after-tax WACC can vary by utility and shall be consistent with **the** utility's existing capital structure.
>
> *Provisional Recommendation #2b*: When performing the PAC test, utilities shall input the interest rate for a two year treasury **bond** for residential consumers and the WACC for commercial and industrial customers.

b. Expected Useful Life

The expected useful life (EUL) of a measure is the amount of time that a measure is expected to remain in useful service and typically is estimated as the average physical life of the device, adjusted for "persistence,"[2] which adjusts for events such as a customer removing a functioning CFL and replacing it with the original incandescent bulb. The EUL is the period of time the energy efficiency measure provides benefits, and is typically used as the duration for calculating the net present value (NPV) required in the cost-effectiveness tests. Long-lived measures such as building shell and envelope measures (e.g., window replacements or attic insulation) may have EULs of 30 years, while shorter-lived measures such as CFLs may last only several years. With long-lived measures, there is increased uncertainty as to the quantity and value of the energy savings.

> *Provisional Recommendation #3:* The life of the measure used for calculating the present value benefits of a measure should reflect the average physical life of the measure, adjusted for the expected persistence of the measure. The present value analysis should consider only the life of the energy efficiency measure for which the customer receives an incentive.

c. <u>Utility and Program Costs</u>

i. Incremental Measure Cost

Energy efficiency measures can generally be installed in three situations: (1) at the time of new construction,; (2) at the time of replacement of an old unit that has failed (replace on burnout);, and (3) prior to the failure of an existing unit (early retirement). The incremental measure cost depends upon the situation in which the measure is installed.

> *Provisional recommendation #4a:* If a measure is installed (1) at the time of new construction, or (2) at the time of replacement of an old unit that has failed (replace on burnout), the incremental measure cost is the difference in cost between the efficient unit and the standard unit, meeting federal and state code minimum standards, that would have otherwise been installed. We call this incremental measure cost the "buy-up" cost. The buy-up cost generally excludes installation costs since installation costs would have been spent in both cases.

If a new efficient unit were replacing a standard unit that was just installed, the incremental measure cost would be the full cost of the new efficient unit, plus the cost of installation --- since there is no offsetting costs for what the customer would have otherwise had to pay. We call this incremental measure cost the "new installation" cost. This situation often applies to investments equipment, but is not that common for energy efficiency measures.

A more common situation for energy efficiency is the early retirement (situation 3), where an aged, but fully functional unit is replaced by a new efficient unit. At some point in the future, the old unit would have failed in place, if not replaced by the efficient unit. In this case, the incremental measure cost is a blend of the new installation cost and the buy-up cost. The new installation cost would apply for the first x years, and the buy-up cost for the next (y-x) years, where x is the expected remaining life of the old original unit, and y is the expected useful life of the new efficient unit.

> *Provisional recommendation #4b:* To calculate the incremental measure cost of an early replacement measure, the new installation costs and buy-up costs should be converted to levelized values that are constant in real dollars. The incremental measure cost should then be calculated as the present value of the stream of levelized costs, where the levelized new installation cost is assigned to the first x years, and the levelized buy-up cost is assigned to the remaining y-x years.

ii. Utility Incentives

Provisional recommendation #5: The incentive costs should be equal to the planned incentives for each type of measure installed. The incentive will be multiplied by the number of planned installations over the planned program period to estimate to total utility incentive costs. The incentive cost (benefit) is required for the UCT/PAC, RIM, and PCT **tests,** but not for evaluating the TRC test.

iii. Administrative Costs

The administration costs of the energy efficiency program are those costs that are required to operate the utility program, including energy efficiency staff, marketing and outreach expenses, planned evaluation, measurement and verification, and other costs that would be recovered in the utility revenue requirement as a result of the energy efficiency program that are not captured in the utility incentive costs above.

Provisional recommendation #6: The administration costs should be estimated for each utility at the program level and included in the TRC, UCT/PAC, and RIM **test** results. They are not included in the PCT **test** results.

d. <u>Time Specific Avoided Costs</u>

The value of energy efficiency depends on when the energy consumption reductions occur. During peak periods of electricity consumption, the market prices of electrical energy are generally higher. Consumption during these periods can also increase the requirement for generation capacity which can result in increased costs in the generation capacity markets or **the** increased costs for new generation construction, as well as the need for transmission and distribution capacity. Using time-specific avoided costs would recognize and quantify the differences in avoided cost value depending upon on the timing of the load changes. For example, for a ~~summer~~ **summer**-peaking service territory, the value per kWh saved for more efficient air conditioning would be greater than the value per kWh saved of efficient street lighting.

Provisional recommendation #7: Electric utility avoided costs used in the cost-effectiveness calculations should be time-specific. Avoided energy costs should, at a minimum, reflect time of day and seasonal differences by time-of-use (TOU) period (peak, off-peak, shoulder for summer and winter). Avoided generation, transmission, and distribution capacity costs should be presented as separate components and should reflect seasonal differences (winter peak coincident and summer peak coincident demand reductions).

e. Avoided Energy Costs

i. Electrical Energy

In the case of a regulated, vertically integrated utility, avoided electricity costs could be projected from the expected production cost of electricity and the value of deferring generation projects, including a reasonable rate of return. In the instance of **a** ~~distribution-~~**distribution**-only electric utility in a deregulated jurisdiction, avoided electricity costs could be projected in the near term from current forward market prices and in the longer term from long-term forecasts of market prices. Ohio's electric distribution companies, however, do not fit neatly into either of these categories. Pursuant to S.B. 221, Ohio's utilities function in a hybrid environment in which rates are regulated but profoundly influenced by the market.

In the near term, Ohio utility rates are defined by Commission–approved standard service offers (SSOs) within either electric security plans or market rate option plans. In years outside of a ~~Commission–~~**Commission**-approved plan, electricity costs will continue to be anchored by elements within the most recently approved SSO. Even in instances in which a utility exercises its option to go to the market, the resulting electricity cost will be a blend of the bid price and its existing generation service price.

Provisional Recommendation #8a: A utility's electrical energy component cost, during the term of a Commission approved standard service offer, for the TRC, UCT/PAC, or RIM tests will be the energy cost embedded in that standard service offer, including any POLR or standby component.

In order to develop a reasonable proxy for electrical energy costs beyond the term of a Commission approved SSO, a utility will require a forecast for a likely bid price for delivery to its service territory. The actual price will vary whether the territory is within PJM or MISO. It will also vary within the footprint of either regional transmission organization. A utility's actual electrical energy costs will be a function of the weighted average locational marginal price **(LMP)** for all delivery points within its territory. The greatest level of precision may be *available only within* the utility's proprietary forward market curves. Similar information could be developed, however, by using publicly available forward market data from either PJM or MISO. Using ~~publicly~~ **publicly**-available data would enable interested parties to document and verify the projections.

Utilities could develop a forward market price based upon ~~publicly~~ **publicly**-available data using a number of viable methods. The following represents one example. The Commission is interested in receiving comments on this method as well as recommendations for other similarly useful methods.

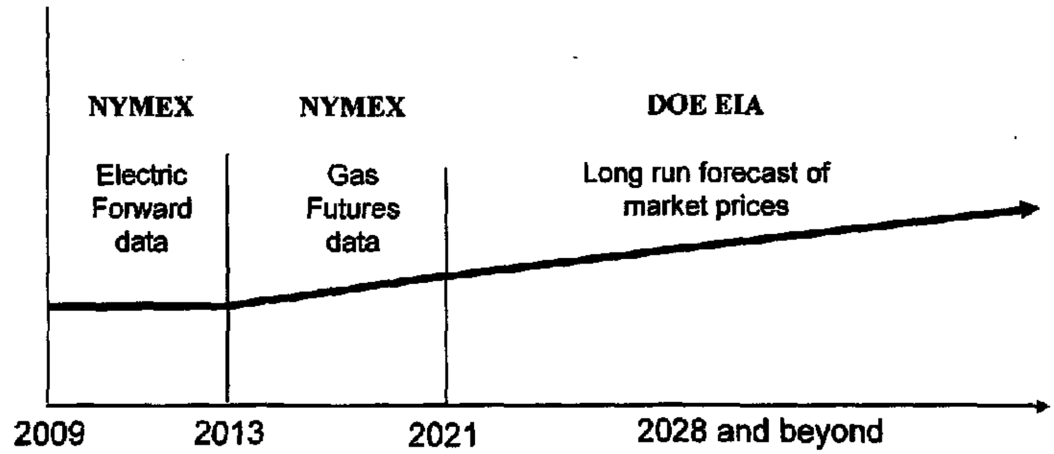
In step 1, the annual average avoided energy costs must be forecasted for as long as the longest ~~Expected Useful Life~~**EUL** of any measure in the energy efficiency portfolio, likely 30 years or more. To span 30 years, several different data sources must be used, each of which spans a different time horizon. Figure 1, below, illustrates three periods of available market prices. In the near term period (for any time period beyond the term of the existing ~~Commission~~ **Commission**-approved SSO), the current forward prices of electricity should be used. Beyond the traded electricity forward data a proxy based on natural gas combined cycle should be used. Finally, a long run forecast completed by the DOE Energy Information ~~Agency~~ **Administration** (**DOE** EIA) should be used.

Forward market prices in the near term are the simplest. These are typically traded by peak and off-peak periods for four or five years into the future. The NYMEX AEP-Dayton hub electricity forward prices should be used from present through the period of traded and available data (approximately 2014 as of mid 2009). While some may note that the electricity forward prices in the outer years may be thinly traded, they are still appropriate since they represent standing offers to buy and sell and are therefore unbiased and more accurate than fundamental forecasts.

Beyond the forward market prices in electricity, the market price should be based on the variable cost of a new natural ~~gas~~ **gas**-fired generation unit. The variable cost combines the market price of natural gas delivered to generation in Ohio, with assumptions about the heat rate and variable operating costs of an assumed marginal generation unit, to forecast annual average energy prices. The avoided fixed costs of the marginal unit are captured in the electricity capacity value described below. To forecast the variable costs, the NYMEX Henry Hub natural gas price which is currently traded through 2021 should be used; there are also publicly traded basis differentials between Henry Hub and delivery in Ohio available for the next several years. Since the basis differentials are typically very small, using the average throughout the NYMEX forward strip is satisfactory. The marginal generation unit should be a new natural gas combined cycle power plant. While there are likely to be new power plants of different types in Ohio in the future, the assumption that natural gas combined cycle will set the market price is reasonable. Publicly available cost and performance data for combined cycle natural gas turbines is available from the **DOE** EIA.

Beyond the forward market prices for natural gas, the Annual Energy Outlook (AEO), which is a long-term forecast published annually by the **DOE** EIA should be used. The **DOE** EIA forecast provides a 30 year forecast by region in the country which can be extrapolated even further as needed to provide a very long-term forecast of avoided energy costs.

Figure 1: Annual Average Generation Marginal Cost Forecast



In Step 2, the energy prices must be differentiated by the time of use periods defined for the analysis. This should be done using at least one year of historical average day-ahead LMP data for the appropriate delivery point(s) of each utility.

There are several approaches possible to convert the historical LMP data to differentiated energy avoided costs. Potentially the easiest is to download available LMP data for the specific utility, then compute the average annual price. Then average the market prices for each of the time of use periods in the LMP data. Finally, compute the ratio of the average price in each TOU period to the average annual price to determine the percent of annual average price to apply in each period. Finally, in each year multiply the annual average forecast computed in Step 1 by the annual average market price ratio. The LMP data necessary for this calculation is publicly-available at the links provided below.

<u>Links</u>

NYMEX Electricity Forwards

NYMEX AEP-Dayton Electricity Forwards: http://www.nymex.com/VM_desc.aspx

Natural Gas Market Proxy
NYMEX Henry Hub Natural Gas Futures: http://www.nymex.com/NG_spec.aspx

Annual Energy Outlook
EIA Long Run Electricity Price Forecast: http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_8.xls

Midwest Hourly Day Ahead LMP Data

http://www.midwestmarket.org/publish/Folder/67519_1178907f00c_-7fdf0a48324a?rev=1

PJM Hourly Day Ahead LMP Data

http://www.pjm.com/markets-and-operations/energy/day-ahead/lmpda.aspx

Provisional Recommendation #8b: In forecasting a likely bid price for delivery to its service territory, a utility will use the most accurate, ~~publiely~~ **publicly**-available data representative of its own service territory. Although published market prices may vary somewhat from each utility's proprietary forward market curves, the benefit of using ~~publiely~~ **publicly**-available data that can be provided to interested parties outweighs the small additional accuracy in using proprietary data. These costs should be made available to interested parties in a non-confidential, non-proprietary format so that interested parties can perform independent benefit-cost analyses

Provisional Recommendation #8c: A utility's electrical energy cost component, after the term of a ~~Commission~~ **Commission**-approved standard service offer, for the TRC, UCT/PAC, or RIM tests will be a blend of its most recent standard service offer and its forecasted bid price in the following relative proportions (SSO/bid): year one 90%/10%; year two 80%/20%; year three 70%/30%; year four 60%/40%; year five 50%/50%; year six 40%/60%; year seven 30%/70%; year eight 20%/80%; and year nine 10%/90%. For year ten and beyond in the post SSO period, the forecasted bid price will be used as the electrical energy cost component for the TRC test.

ii. Ancillary Services

Ancillary services include regulation, spin, non-spin, replacement, schedule/system control/dispatch service, voltage support, real power losses, ~~Blackstart~~ **blackstart**, and imbalance energy. Utility SSOs have embedded ancillary services within their terms. To the extent that ancillary costs are embedded within the SSO electricity energy costs, no further input is required. For **the** ~~post~~ **post**-SSO period, estimates of avoided ancillary services should be included in the electricity avoided costs. The ancillary service costs included should be applicable to ancillary service products that could be displaced or reduced in volume by energy efficiency measures. If appropriate, the ancillary service costs should be disaggregated if the applicability of the costs depends on the characteristics of the energy efficiency measure.

The easiest approach to include ancillary services is to compute the ratio of ancillary services purchases to energy market purchases and then adjus~~ting~~ the energy costs up by this factor. This ratio can be computed by determining the relative share of ~~A/S~~ **ancillary service** costs in market purchases and then applying the same share to the market purchase forecast. The ancillary service share of costs is calculated by summing all revenues of ancillary services and dividing it by the sum of all energy revenues. In PJM, annual expenditures for ancillary services and energy can be found in the annual market report. If similar information is not publicly available for MISO, the PJM value can be used. The ratio of ancillary services costs to energy costs should be on the order 2% to 4%.

Links

PJM 2009 State of the Market Report:
http://www.pjm.com/documents/~/media/documents/presentations/year-in-reivew-2009-markets-andy-ott.ashx

Provisional Recommendation #9: A utility's avoided ancillary services cost should be included within its avoided energy costs in the TRC, UCT/PAC, or RIM **test** calculation. During the SSO period, the cost is defined by the SSO. In the post SSO period, the utility will compute the ratio of ancillary services purchases to energy market purchases and then apply that ratio to the energy price forecasted pursuant to Provisional Recommendation #8c.

iii. Air Emissions of Electricity Generation

The costs of permits for **emissions of** criteria air pollutants ~~of~~ **for** electric generators (e.g., permits to release SOx, NOx, and particulate matter) are already embedded in electricity market prices because generators must include the cost of procuring air permits in their bids to generate and sell electricity into the wholesale market. Therefore, estimates of criteria pollutant costs only need to be added to the avoided costs for the years when those costs are based on a natural gas combined cycle proxy (note: SOx are essentially zero for natural gas generation and therefore only the cost of NOx and particulates need be included). These costs will be a relatively small share of the total avoided costs.

Similarly, there has been increased activity at the federal level, including proposed legislation in both the House and the Senate, for developing a cap and trade market system that would require electric generators to purchase CO2 allowances in order to emit CO2. The U.S. EPA has declared that CO2 emissions are a pollutant and is exploring processes to regulate it. Most recently, a two-judge panel of the United States Court of Appeals for the Second Circuit, in New York, has ruled that eight states can proceed with a suit against coal-fired generators in the Ohio River Valley for emitting CO2. In these circumstances, the Commission must make a policy decision of whether or not to include a forecast of the potential future costs of CO2 allowances that would be borne by Ohio ratepayers in the cost-effectiveness screening evaluation of a portfolio of energy efficiency programs should a market system be established in the future. If the Commission were to determine that a potential CO2 cost should be included, it would then need to determine when the component should be added as well as the value of this component. In facing this choice, the neighboring states of Pennsylvania and Michigan, which have also recently adopted energy efficiency legislation, came to opposite conclusions. Pennsylvania does not include a CO2 component at all, while Michigan includes one in all future forecasts beginning immediately. If no CO2 regime is mandated, including CO2 in the TRC, UCT/PAC, or RIM test would result in ~~over~~-**over**-investment in energy efficiency. If no CO2 component is included, however, and a CO2 market is established, Ohio rate-payers will have under-invested in energy efficiency and missed an opportunity to reduce impacts from CO2 control.

Provisional Recommendation #10a: Utilities should add a CO2 component as an avoided energy cost under the TRC, UCT/PAC, and RIM tests for the time period beginning **in** 2015 and beyond.

In order to assess and account for the potential impact of the cost of CO2 allowances as part of screening the cost-effectiveness of an energy efficiency portfolio, assumptions must be made ~~of~~ **on** the cost of such allowances and the expected marginal emissions rate by ~~time-of-use~~ **TOU** period and an estimate of the cost ~~of a~~ **per** tonne of CO2. As there is presently no market, any calculation would be speculative. An approach to estimate the marginal emissions rate and cost of CO2 allowances is provided below.

The simplest approach to compute marginal emissions rates is to compute the implied marginal heat rate and fuel source (coal or natural gas) based on the forecasted electricity price and a forecast of fossil fuel prices. To determine the implied heat rate for both natural gas and coal units, subtract an estimate of variable operating cost from the market price ($/MWh) in each ~~time of use~~ **TOU** period, ~~and~~ then divide by the delivered fuel price ($/MMBtu). If the implied natural gas heat rate is unfeasible, say below ~6500 Btu/kWh, then that period has coal generation as the marginal generation type. Otherwise, natural gas is assumed to be on the margin. With the heat rate and the fuel type determined, the marginal emissions rate can be computed as the CO2 emission rate of the fuel (tonnes of CO2/MMBtu) times the heat rate (Btu/kWh).

Synapse Energy Economics, Inc. has conducted a meta-analysis of many of the forecasts done in consideration of the federal climate change bills. This analysis provides a low, medium, and high forecast based on varying factors. The low forecast starts at $10/short ton of CO2 in 2013 and rises to $23/ton in 2030. The high forecast starts at $30/ton in 2013 and rises to $68/ton in 2030. PJM has converted these figures into a likely range of $11-15/MWh in additional energy costs in 2013 due to CO2.

Link:

Synapse Energy Economics, Inc. CO2 forecast: http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

Provisional Recommendation #10b: Utilities should add a CO2 avoided cost component for the TRC, UCT/PAC, or RIM test of $11.00/MWh beginning in 2015. Alternatively, the Commission seeks commenters' suggestions for a methodology to use option values to determine the appropriate price.

iv. *Alternative Energy Benchmark Costs*

S.B. 221 mandates that a growing proportion of a utility's energy portfolio come from various alternative energy resources annually up until 2025, at which point the utility must maintain a portfolio with at least a 25% alternative energy. The implementation of energy efficiency will allow a utility to purchase less energy from presumably higher cost alternative energy resources. That benefit should be reflected in the Ohio TRC calculation.

Provisional Recommendation #11: Utilities should account for alternative energy benchmark costs as an avoided energy cost in the TRC by assuming a resource mix that meets the annual alternative energy benchmark and estimate an average cost for each type of resource. The avoided energy cost used for energy efficiency evaluations should be x percent alternative energy resource cost and (1-x percent) market purchase costs, where x is the alternative energy benchmark percentage for that year.

v. *System Energy Losses*

If energy is never delivered as a result of energy efficiency, then system energy losses do not occur and the utility is able to avoid the cost of this system energy loss. The value of avoided system energy losses is a component for the TRC, UCT/PAC, and RIM tests.

Provisional Recommendation #12: Utilities will calculate and include an avoided system energy loss component when conducting TRC, UCT/PAC, and RIM tests. Utilities should develop their own estimates of marginal system losses based on the performance of their transmission and distribution systems. For increased accuracy, the losses should be calculated from the market hub used for the energy value to the customer meter and may vary by time-of-use period. Care should be taken to estimate the marginal losses rather than the average losses. The marginal losses are the savings in energy for a reduction in demand, not the average energy lost during system delivery.

vi. *Hedging Costs*

The methodology for determining energy costs described above includes the value of reduced volatility in energy costs that energy efficiency provides. The market prices used for the energy (both electricity in the near term, and natural gas in the medium term) are for firm delivery at fixed future prices. Therefore, these avoided costs already include ~~any~~ **a** premium for fixing the costs. Similarly, any fuel costs for new plants or purchase costs for renewable energy~~,~~ should ~~be~~ reflect the cost of firm delivery, so energy efficiency **will**~~would~~ not provide any delivery risk improvement.

Provisional Recommendation #13: Utilities should not include any hedging component in the avoided energy calculation for the TRC, UCT/PAC, or RIM tests.

vii. *Summary of Avoided Energy Costs*

In summation, the avoided energy costs may be expressed as follows:

$$\text{Avoided Energy Cost}_{TOU,YR} =$$

$$\{(\text{Electricity Market Price}_{TOU,YR} * (1+ \text{A/S Ratio}) +$$

$$\text{CO2 Emissions Rate}_{TOU,YR} * \text{CO2 Emissions Cost}_{YR}) * (1\text{-RPS Share}) +$$

$$\text{Alternative Energy Resource Cost} * (\text{RPS Share})\} * (1 + \text{Loss Factor}_{TOU})$$

f. <u>Avoided Capacity Costs</u>

i. Capacity Purchases or Generation Construction

Provisional Recommendation #14a: A utility's capacity component cost~~,~~ during the term of a ~~Commission~~ **Commission**-approved SSO~~,~~ for the TRC, UCT/PAC, or RIM test will be the capacity cost embedded in that SSO.

Provisional Recommendation #14b: For ~~post~~ **post**-SSO capacity costs, utilities should use capacity purchases (when available) or new generator construction, less net operating revenues to evaluate the avoided generation capacity avoided costs. Capacity market prices are available three years into the future from PJM's Reliability Pricing Model (RPM). Because MISO currently does not have a capacity market, utilities falling under MISO's jurisdiction should use PJM's near term capacity values. If MISO implements a capacity market, the appropriate capacity market prices from MISO should be applied. Beyond the SSO and three year capacity market, the capacity value should trend towards the cost of new entry (CONE) for a new generator to provide capacity as load grows in the region. To compute the trend, each utility should choose a 'resource balance year' by which new generation capacity must be installed, given the planned energy efficiency of that utility and others in the region, and then trend towards the CONE in that year. The CONE that should be used is calculated within the PJM RPM market process (or MISO market process should it be established). The CONE is based on the estimated cost of a new entrant minus the margin it could expect to make from participating in the energy markets.

Links:

PJM RPM: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

2012-2013 CONE: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-net-cone-calculation.ashx

ii. *Transmission and Distribution Facilities*

Energy efficiency programs geographically targeted to areas on a utility's transmission and distribution system that require upgrade or that experience congestion and congestion pricing provide value if the energy efficiency program can reduce congestion and its related premium pricing or delay investment in transmission and distribution. This value is appropriately captured as an avoided capacity cost in the TRC, UCT/PAC, or RIM test.

The value of avoided transmission and distribution (T&D) capacity can be calculated using the marginal transmission capacity cost or marginal distribution capacity cost (MTCC or MDCC). The MTCC or MDCC is relatively simple to calculate if the future 5-year or 10-year planned transmission or distribution capacity expenditures are available for each utility. If the transmission and distribution capital plans are not available, it is possible to use a proxy based on either the MTCC and MDCC results in other utility service territories or the transmission and distribution tariffs until Ohio-specific transmission costs and EDC-specific marginal distribution costs can be calculated. Both of these approaches for a proxy are second best because they do not link the T&D avoided costs to future T&D investments that energy efficiency may be able to avoid. The following table shows an example of the calculation necessary to compute the MDCC for a utility.

Table 1: Sample T&D capacity cost calculation

Example Marginal Distribution Capacity Cost (MDCC) Calculation			
A	Net Present Value Distribution Growth-related Capital Expenditures (1)	$100	Million
B	Horizon for Net Present Value	5	Years
C	Forecast Inflation	2%	
D	Post-tax Weighted Average Cost of Capital	8%	
E	Average Load Growth per Year	50	MW
F	MDCC ($/kW) MDCC = A * (1 - (1+C)/(1+D))/E * 1000	$111	$/kW
G	MDCC ($/kW-year) (2)	$27.83	$/kW-year

(1) This should include only those distribution capacity investments necessary due to load growth. Costs for new customer connections should not be included. Additional transformers or new substations in areas with service should be included. Typically land costs are also excluded.

(2) The annualized MDCC is the total MDCC ($/kW) levelized over the horizon used to collect the capital expenditures (from B).

Provisional Recommendation #15: To the extent information is available, utilities should submit avoided transmission and distribution capacity costs at the program level of analysis for the TRC, UCT/PAC, or RIM tests.

iii. Capacity Losses

1. System Peak Demand

Provisional Recommendation #16: The market value of capacity should be increased for peak marginal losses between the market hub and the customer meter. As with the energy loss factors, each utility should develop ~~their~~ **its** own estimates of marginal system losses at peak periods.

2. Transmission and Distribution

Provisional Recommendation #17: Similar loss factors should be calculated for (1) the transmission system down to the customer meter and (2) the distribution system down to the customer meter. Those factors would be applied to the transmission and distribution capacity avoided costs, respectively.

iv. *Coincidence Factors*

Coincidence factors are used to reflect the fact that the value of a demand reduction depends upon timing of that demand reduction compared to the need for the reduction. ~~**Coincident**~~ **Coincidence** factors should be defined separately for generation, transmission, and distribution peaks, as the timing and duration of the critical peak periods can vary for generation, transmission, and distribution. Coincidence factors should clearly state their timing basis so that the avoided capacity costs can be calculated appropriately. There are several ways to develop and specify coincidence factors, and the choice of methods would depend upon each electric utility's unique capacity situation. Some examples are provided below and labeled "Example 1" through "Example 4." The Commission looks to each utility to produce and justify the coincidence factors appropriate to their service territory, and we encourage utilities to work cooperatively to develop common factors where appropriate (such as generation coincidence factors for the MISO or PJM territories). The Commission has adopted a coincident peak demand savings definition for the calculation of compliance with statutory benchmarks. It seeks comments as to whether the definitions for measuring compliance and the measures for calculating avoided costs should be the same.

Example 1: 70% weight to 3pm summer weekday, 30% weight to 7pm winter weekday. These are simple coincidence factors for a utility that peaks in the summer and winter. A measure that reduces demand by 1kW in the summer only, would receive only 70% of the avoided capacity benefit. With this simplest formulation, the formula for seasonal capacity savings would be the following.

$$\text{Capacity Savings}_{\text{SEASON, Measure}} =$$

$$\text{Peak Demand Savings}_{\text{SEASON, Measure}} * \text{Coincidence Factor}_{\text{SEASON, Measure}}$$

If more information is available, additional detail can be added to calculate the capacity savings using similar approaches described below, but with an hourly level of granularity during peak periods.

Example 2: Top 100 summer peak load hours. These factors would assign 1% of the capacity value to each of the 100 most critical hours in the summer. The advantage of these coincidence factors is that they can differentiate the capacity value from a measure that reduces demand for 20 of those hours, versus one that can reduce demand for all 100 hours. The number of hours should reflect the number of hours in a year in which there is a high enough load, relative to available generation capacity, to create a reliability concern due to small reserve margins.

Example 3: 3pm to 6pm on consecutive weekdays during June through August. The Commission recently adopted a definition for coincident peak-demand savings for purposes of calculating compliance with the statutory benchmarks. This definition assigns equal weight to the twenty afternoon hours during the worst heat in the year. While such a definition is clearly applicable to ~~Deemed~~ **deemed** ~~Calculated~~ **calculated** ~~Measures~~**measures**, its specificity is also useful for judging reasonable capacity values for other measures.

Example 4: Hourly Loss of Load Probabilities (LOLP). These factors would be hourly weights that are highest during the most critical forecast hours, and zero for the majority of hours in the year. The hourly LOLP factors would be normalized so that they sum to 100%. Applying these hourly factors to the expected hourly demand reduction pattern of a measure would yield the weighted average demand reduction that can then be multiplied by the avoided capacity cost to estimate the avoided capacity benefit of the measure.

The actual coincidence factors that would be appropriate for each utility can vary and will depend upon the information that each utility already has available and can be released publically.

g. Natural Gas Avoided Costs

For evaluation of the TRC test, monetized (non-externality) co-benefits of energy efficiency programs are typically included. This is notwithstanding that utility goals are based on achieving the energy and capacity targets. There are a range of potential co-benefits that improve the cost-effectiveness of energy efficiency ~~the~~ measures, including natural gas savings common with shell measures that reduce natural gas use for heating. Water savings that occur with high efficiency appliances that use less water, such as washing machines, are another source of potential co-benefits. Of these co-benefits, natural gas savings are expected to be the largest source of monetized savings that would affect the results of the TRC test. Along with the savings of the natural gas commodity, there are reduced air emissions associated with reduced natural gas usage. Of these reduced air emissions, such as ~~criteria emissions such as~~ NOx and particulates as well as CO2, there may be some that reduce allowance permits. However, small source natural gas consumers do not typically have to purchase these permits. Since the markets for CO2 are not formed, it is unclear whether the end-user or natural gas supplier would have to purchase CO2 allowances for the natural gas that is sold.~~;~~ ~~however~~ ~~M~~most federal proposals, **however,** would include CO2 allowances for all fossil fuels.

Provisional Recommendation #18a: Co-benefits (and co-costs) of natural gas savings (or increases) should be included in the TRC and PCT cost-effectiveness calculation. For example, more efficient lighting may also lower internal building heat gain, which could result in additional electricity reductions in the summer, but increased natural gas heating requirements in the winter. These co-benefits (and co-costs) should not be included in the UCT-/-PAC test results of an electric utility. While natural gas co-benefits (and co-costs) should be included in cost-effectiveness, the program impacts should be measured strictly in terms of electric energy and capacity saved.

Provisional Recommendation #18b: Co-benefits from water are likely to be smaller than natural gas, but should be included in the TRC and PCT **tests** ~~as well~~ based on an estimate of water savings per measure and a forecast of the value of avoided water.

Provisional Recommendation #18c: While costs for CO2 emissions could be included in the valuation of the natural gas co-benefits (or costs) of energy efficiency measures (since in a carbon regulated regime this is likely to be a real avoided cost~~,~~), at this time, because of the difficulty in projecting this value and the relative size of the cost, it need not be included.