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Q. Describe how you obtained your estimates of environmental adder costs.

A. The cost of SO_2 allowances was based on a PHB Hagler Bailly forecast of SO_2 allowance prices. The cost of NO_x environmental adders was estimated by PHB Hagler Bailly based on an analysis of the SIP Call impacts in the power sector. The SO_2 and NO_x emission rates for CG&E units were provided to me by CG&E. SO_2 emission rates for other coal-fired units were derived by PHB Hagler Bailly from public data. I modeled NO_x emission rates for coal units in ECAR, SERC, MAIN, NYPP and MAAC based on the controls required to attain the Ozone Transport Region and SIP Call targets, and estimated NO_x emission rates on other fossil units based on the type of fuel burned. The CO_2 adder costs were based upon a survey of publicly available studies on the impacts of climate change policy on the electric utility industry.

Q. Why have you included SO_2 emissions costs?

A. Title IV of the Clean Air Act Amendments of 1990 authorized the U.S. Environmental Protection Agency (EPA) to require electric utilities to reduce emissions of SO_2 in two phases. Phase I covers the period 1995 through 1999 and Phase II covers the period from 2000 onward. EPA implemented these reductions with a market-based cap-and-trade emission allowance mechanism. In Phase II, each electric utility plant over 25 megawatts is allocated a certain number of SO_2 emission allowances, each representing one ton of SO_2 emissions. Each utility plant must acquire enough SO_2 allowances to cover its actual emissions. If the utility has fewer or more SO_2 allowances than emissions, the utility can purchase or sell SO_2 allowances on the open market to cover the difference.

Q. How have you calculated SO_2 emission costs?

A. SO_2 adders are included in fuel prices in the GE MAPS runs. They are based on the actual SO_2 emission rate at each plant (expressed in pounds of SO_2 per million Btu) multiplied by the cost of SO_2 emission allowances measured in dollars per pound (see Exhibit JMS-3). In his analysis of plant valuation, Dr. Pifer nets the SO_2 emission allowances consumed at CG&E's plants (based on the GE MAPS output) against the allowances received by CG&E from the EPA under Phase I and Phase II of Title IV of the Clean Air Act Amendments of 1990.

Q. Why have you included NO_x emissions costs?

A. Additional control of NO_x from utility sources in the northeast U.S. is already occurring as a result of regional regulatory actions taken under the Clean Air Act Amendments of 1990. The first wave of additional controls began this May in the 12-state Ozone Transport Region (OTR), and were intended to reduce summertime NO_x

emissions by 55 - 65 percent from 1990 levels.[2] A second set of controls are likely to be implemented in a broader 22-state region beginning in 2003, and are designed to achieve an 85 percent reduction in NO_x emissions relative to 1990 levels.

Q. What allowance price did you use for the OTR ?

A. I assumed that allowance prices in the OTR for 2001 would be $3,000 per ton in 1997 dollars ($3,066 in 1999$). This is based on the conclusion that the volatile allowance prices experienced in 1999 – which peaked at over $7,000 per ton in the spring and fell to below $1,000 per ton by the end of the first ozone season (May 1 through September 30) – eventually will equilibrate with the marginal costs of seasonal NO_x controls at the OTR levels. Since the SIP Call requirements generally are tighter than the proposed OTR control levels for 2003 (about a 75% reduction from 1990 levels) I assume that the regional NO_x allowance price in the 22-state region (described below) prevails in the OTR in 2003 and beyond.

Q. What is the basis for the SIP Call requirements?

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2 The Ozone Transport Region (OTR) covers a twelve-state area and includes: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. The District of Columbia is also considered to be part of the OTR. Since CG&E does not own any units in the OTR, and since ECAR prices are only indirectly influenced by these regulations, I have omitted detailed explaination of their construction.

A. On September 24, 1998, the EPA finalized the Ozone Transport rule (the 22-state SIP Call) that has the effect of tightening the OTR MOU requirements and extending them to other states in 2003.[3] The emission targets contained in the SIP Call are based upon electric generating sources (over 25 MW) in each state attaining an average emission rate of 0.15 lb. NO_x per million Btu. The EPA also formulated a model allowance cap-and-trade system and allowance allocation methods in the final rule. Although states ostensibly can pursue a wide range of alternative NO_x reduction plans in order to attain the statewide emission caps in the rule, I assume that most states ultimately will enact rules that mirror the EPA model allowance scheme in order to gain EPA approval of the SIP. Pennsylvania, for example, has proposed allowance allocation rules that are effectively identical to the EPA model rule. Some states, including Ohio, are prepared to offer less stringent control programs that clearly are not approvable under the final rule, which would allow EPA to substitute the proposed Federal

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3 Published in the Federal Register on October 27, 1998 at 63 FR 57356. The 22 states that are required to revise their State Implementation Plans (SIPs) under the "SIP call" rule are: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin. The District of Columbia is also included.

Implementation Plan (FIP) that incorporates the EPA model cap and trade system.[4]

Q. Aren't the SIP Call rules being challenged in court?

Yes, electric utilities and eight Midwestern and Southern states have challenged the validity of the SIP Call as promulgated by EPA, especially in light of legal uncertainty regarding the National Ambient Air Quality Standard for Ozone.

Q. If the SIP Call rules are being challenged in court, why are you assuming their implementation?

A. The lawsuits challenging the validity of the SIP Call were heard on November 9, 1999. On May 25, 1999, the U.S. Court of Appeals for the D.C. Circuit issued a stay that exempted states from submitting SIPs by the initial deadline in the final rule (September 30, 1999) pending the outcome of the legal case against the rule. While it is not possible to predict the outcome of the legal action, I believe that it is prudent to model the SIP call implementation in its current form for the purposes of projecting electricity prices and generation station operating costs.

Moreover, even if the SIP call is delayed or modified, EPA currently is pursuing a similar regulatory program under Section

4 "Federal Implementation Plans to Reduce the Regional Transport of Ozone; Proposed Rule. *Federal Register* October 21, 1998, pp. 56394-56427.

126 of the Clean Air Act. Under Section 126, downwind states can petition EPA to control sources in upwind states if they believe emissions from other states impedes their attainment of the ambient air quality standards. On April 30, 1999, EPA promulgated a final rule under the Section 126 affirming petitions from 8 states for additional NO_x controls in upwind states, but deferred implementation of the required emission reductions pending the submission of State Implementation Plans under the SIP call.[5] However, EPA issued an interim final rule on June 11, 1999 indicating its intent to move forward with the Section 126 requirements in light of the legal issues surrounding the SIP Call.[6] On October 29, 1999, a federal appeals court denied a motion by industry petitioners to stay the Section 126 final rules, clearing the way for their implementation.[7] Thus, I conclude that the best

5 "Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport; Final Rule" *Federal Register* May 25, 1999, pp. 28250-28328. The 8 petitioning states are Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Pennsylvania and Vermont.

6 "Interim Final Stay of Action on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport; Interim Final Rule" and "Findings of Significant Contribution and Rule-making on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport; Proposed Rule" *Federal Register* Volume 64, No. 121, Thursday, June 24, 1999 pp 33956-33967.

7 *Appalachian Power Co. v. EPA, D.C. Circuit 99-1200, 10/29/99*, as reported in "Federal Court Denies Industry Motion to Stay Section 126 Rule on NO_X Controls" *Daily Environment Report* No. 214 Friday, November 5, 1999, p. A-5.

available evidence shows that NO_x restrictions are going to be implemented.

Q. How would the Section 126 program work?

A. EPA initially is proposing to require utilities to reduce NO_x emissions in 12 states and the District of Columbia by May 1, 2003 in a manner identical to the recommended emission allowance system under the broader SIP Call.[8] The Section 126 program covers the electric generation sector in ECAR, MAAC, NYPP and part of SERC. Although the Section 126 program would affect fewer states, the impacts in the states surrounding CG&E's Ohio jurisdictional plants would be effectively identical to those I modeled under the SIP call.

Q. How did you model the impact of the SIP Call?

A. I analyzed all steam electric units in the 22-state region to estimate equilibrium NO_x allowance prices, regional emissions, unit-by-unit compliance choices, and unit emission rates. My analysis calculated the least cost compliance option for each unit – either control technology or allowance use – to meet the 22-state emission cap. I also calculated the increase in variable operating

[8] The 12 states that EPA determined to impair the petitioners' attainment under the current 1-hour ozone standard are Delaware, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia and West Virginia. Five of the 8 petitioning states also based their Section 126 petitions on the new 8-hour standard that has been remanded back to EPA ; EPA is not taking action on those petitions at this time. EPA also has received new petitions from Delaware, New Jersey and Maryland, and additional Section 126 petitions from other states based on the current 1-hour standard are expected.

costs for each affected unit, which is comprised of either allowances (if the plant remains uncontrolled) or the variable O&M of the compliance technology chosen plus the allowances consumed at the lower emission rate.

Q. What were the results of the SIP Call allowance market analysis?

A. A NO_x allowance price of $3,500 (in 1997 dollars, or $3,577 in $1999) induced enough control technology over the 22-state region to attain the emission cap in 2003. Allowance market prices will tend to equilibrate at the marginal cost of the "last" ton removed under a cap-and-trade program. Incidentally, the allowance price was very close to the EPA's own estimate of marginal cost of attaining the SIP Call emission target of $3,000 in 1990 dollars (roughly $3,680 in 1999 dollars).[9]

NO_x allowance prices in the SIP call region are assumed to remain constant in real terms. This is consistent with the observations that few old sources are retired in the modeling period and that new sources have negligible NO_x emissions that

9 *Regulatory Impact Analysis for the NO_X SIP Call, FIP and Section 126 Petitions Volume 1: Costs and Economic Impacts.* US EPA Office of Air and Radiation September 1998 (EPA-452/R-98-003), page 6-31.

will not put upward pressure on allowance prices. This is also consistent with EPA analysis of the final rule.

Q. How have you calculated NO_x emission costs?

A. NO_x emissions costs were included in the fuel price inputs into GE MAPS for the months of May through September, which is the period referred to as the "ozone season" in both the OTR and the 22-state SIP call. The NO_x adders are calculated first by multiplying the NO_x emissions rate (in pounds of NO_x per mmBtu) times the allowance price (expressed in \$/lb. of NO_x). For coal units, the emission costs will also include the variable O&M of any control technology installed on these units. For CG&E's units, the control technology, emission rates, and variable operating costs were furnished by CG&E and were inputted directly into the GE MAPS model.

Q. What allowance allocations did you assume?

A. For 2003 and later, I used the allowance allocation formulas outlined in the EPA SIP Call Final Rule to give the CG&E units allowances for the ozone season beginning in 2003 and thereafter.[10] For the ozone seasons 2003 to 2005, the formula gives each unit allowances equal to 0.15 lb. NO_x/mmBtu times the

[10] Subpart E §96.42- found at 63 FR 57524, October 27, 1998.

average of the highest two heat input totals (May-September) recorded in 1995, 1996 and 1997, multiplied by 0.95 (a factor EPA recommends states apply to existing plants to retain 5% of the aggregate allowance allocation for new sources in the early years). For ozone seasons beginning in 2006, the formula gives allowances to each unit equal to 0.15 lb. NO_x per mmBtu times the heat input recorded at the unit during the ozone season four years earlier, times 0.98 (the new source reserve factor for years beginning in 2006). Therefore, units that retire continue to receive allowances for four years after retirement, but none thereafter.

In his analysis of plant valuation, Dr. Pifer nets the NO_x emission allowances consumed at CG&E plants (based on the GE MAPS output) against the allowances expected to be received by CG&E from regulatory agencies.

Q. Why have you included CO_2 costs in your analysis?

A. Costs for controlling CO_2 emissions are expected to be incurred sometime before 2010 as a result of the United States participating in the United Nations Framework Convention on Climate Change[11] and the Kyoto Protocol to the Convention signed December 10,

[11] United Nations Intergovernmental Negotiating Committee for a Framework Convention on Climate Change, *United Nations Framework on Climate Change*, May 1992.

1997.[12] The United Nations Framework Convention on Climate Change is an international agreement with an ultimate objective to achieve "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[13] The Kyoto Protocol requires the U.S. to reduce greenhouse gas emissions to a level 7 percent below 1990 levels by the 2008-2012 period. The Protocol includes several provisions that could give countries flexibility in achieving reductions domestically or acquiring emission offsets from other countries. Carbon dioxide is the dominant greenhouse gas, and fossil-fuel fired electricity generation is a major source of CO_2 emissions.

The CO_2 related costs in my analysis includes a conservative estimate of the economic impact of domestic climate change policies responding to the Kyoto Protocol, one which results in higher fuel costs and electricity prices through the imposition of a marketable permit system for CO_2 emissions. It is based upon my analysis of the Kyoto Protocol, review of numerous economic studies of CO_2 reduction policy, as well as my view of the likely

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12 United Nations Framework Convention on Climate Change, *Kyoto Protocol to the United Nations Framework Convention on Climate Change*, December 10, 1997.

13 *Framework Convention on Climate Change*, Article 2.

form of U.S. domestic policy and evolution of international policy in the climate change area.

Q. What climate change policy was assumed in your analysis of the most likely environmental scenario?

A. I assumed that by 2010, a policy would be implemented that would subject utilities to a \$10 cost per each ton of CO_2 emitted (1997 dollars). The policy assumes that CO_2 allowances are either given or auctioned to fuel suppliers, or, equivalently, that utilities would have to purchase allowances in order to emit CO_2.

Carbon factors published by the EIA show that coal averages 207.9 pounds of CO_2 per mmBtu, distillate fuel emits 161.3 pounds of CO_2 per mmBtu, and natural gas contains 117.0 pounds of CO_2 per mmBtu. A \$10 per ton of CO_2 adder translates into a generation cost increase of \$9.87 per MWh for a coal plant with an average heat rate of 9,500 Btu/kWh, but only an additional \$3.86 per MWh in costs for new natural gas combined cycle plants with an average heat rate of 6,600 Btu/kWh.

Q. Why do you assume that utilities would not receive emission allowances under a CO_2 control policy?

A. There is general recognition that the CO_2 issue is qualitatively different than the SO_2 or NO_x programs, which involve a few hundred to at most two thousand major sources. A viable CO_2

control program would be national in scope and involve all major fuel consuming sectors. The difficulty of assigning CO_2 allowances to hundreds of thousands of combustion sources means that an allocation to direct emitters is impractical. This reasoning is explained in a recent proposal for a domestic CO_2 allowance program by policy analysts at Resources for the Future:

> We propose that the program be administered "upstream" to obtain the broadest possible coverage. Broad coverage guarantees that all sources of carbon dioxide face the same incentive to cut back and therefore aggregate reductions are obtained at the lowest possible cost. This should be true regardless of whether those reductions occur among electric utilities, in the transportation sector, or elsewhere. In an upstream program, we focus on domestic energy producers (and importers) in order to obtain this broad coverage at the lowest possible administration and monitoring cost.
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> In particular, we would require energy producers to obtain permits equivalent to the volume of carbon dioxide eventually released by the fuels they sell. By collecting permits at the mine mouth for coal, the refinery gate for crude oil, and at the initial point of distribution for natural gas, virtually all domestic emissions are covered by roughly two thousand

collection points. This is then augmented by a permit requirement on imported fuels along with exemptions for non-combustion use or export. The key point is that this approach provides the same incentives as a more complex, more expensive, and less comprehensive downstream program focused on end-users.[14]

It is also important to point out that most economic analyses of climate change policy assume that allowances are either auctioned to emitters or primary fuel providers, or that CO_2 emissions are taxed through the carbon content of fuel.[15] Both cases are equivalent from the perspective of a utility fuel buyer to an upstream allocation of permits.

Q. How did you choose $10 per ton of CO_2 as an emission price?

A. The $10 per ton of CO_2 allowance price represents a very conservative figure compared with most estimates of the impact of policies to implement the Kyoto protocol. However, it is consistent with two plausible scenarios of policy implementation. Under one scenario, the successful development of international trading

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14 "A Proposal for Credible Early Action in U.S. Climate Policy" by Raymond Kopp, Richard Morgenstern, William Pizer and Michael Toman, Resources for the Future, February, 1999.

institutions allows the U.S. to meet its commitment under the Kyoto Protocol mainly by purchasing large quantities of greenhouse gas emission reduction credits from other countries at relatively low cost. Under another possible scenario, the international emission trading mechanisms outlined in the Kyoto Protocol do not evolve as rapidly, but industrialized countries, including the U.S., renegotiate far less stringent emission reduction targets for the 2010 timeframe.

Many economic studies of policies that reduce emissions to the levels envisioned in the Kyoto protocol show high costs – reaching \$90 per ton of CO_2 reduced – but do not in general assume that the U.S. is able to purchase cost-effective emission offsets from other countries as allowed under the Kyoto Protocol.[16] However, analyses that incorporate options to acquire emission offsets indicate significant cost savings, usually 50% or more. Even when analysts assume perfect international trading, carbon permit prices typically exceed \$10 per ton of CO_2. My \$10/ton

[15] *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* Energy Information Administration, October 1998 (SR/OIAF/98-03), pp.11-12 and p. 120.

[16] See *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (Energy Information Administration, October 1998) Table 30 for comparisons of studies that show allowance costs of \$221 to \$348 per metric ton of carbon. Analyses of climate change policy impacts use different measures to report results. A molecule of CO_2 is 3.67 times heavier than its carbon atom. A metric ton is 1,000 kilograms, 2,205 pounds, or 1.1 short tons. Therefore, \$10 per short ton of CO_2 is equal to \$36.67 per short ton of carbon, and \$40.33 per metric ton of carbon.

assumption, therefore, is a conservative estimate of the implementation of policies to address climate change, and higher costs are certainly possible in the time period considered.

Q. Why include climate change policy costs given the uncertainties surrounding the ratification of the Kyoto Protocol?

A. While the Kyoto Protocol, in its current form, will not be ratified by the U.S. Senate in the current session, I believe that domestic climate policy steps are very likely over the next decade. This judgment is shared by many in the energy industry. In a recent survey of U.S. and Canadian utility industry executives, 60 percent of the respondents said that they expect requirements to invest in greenhouse gas reductions, with 78 percent of utility executives from the coal-dependent Midwest expecting to incur costs from compliance with the Kyoto Protocol. Only 11 percent believed that no investments would be required.[17] Several bills have been introduced in the U.S. Congress that would enable companies making greenhouse gas reductions before January 1, 2008 to earn

[17] *1999 Energy Industry Outlook*, Washington International Energy Group, 1999, p 35-36.

credit against eventual CO_2 requirements.[18] These bills have garnered support in the energy sector, indicating that many market participants anticipate the adoption of emission control measures over the next decade (since the credits would only have market value if controls are adopted).

Q. Are there other environmental policies that would adversely affect coal-fired generation that are not taken into account in your analysis?

A. Yes. There are several proposals arising from the Clean Air Act that, when implemented, would adversely impact coal-fired generation in ways that could be similar to the CO_2 adder. The two most prominent are new National Ambient Air Quality Standard (NAAQS) for fine particulates (particles with diameters less than 2.5 microns, or $PM_{2.5}$) that will result in substantial additional SO_2 reductions and possible regulatory requirements on mercury from coal-fired generation. In each case, EPA estimates that compliance in the electricity sector with these likely policies run into the billions of

[18] Most recently, see Credit for Voluntary Reductions Act (S. 547) introduced by Senator Chafee (R-RI), et. al on March 4, 1999 and Credit for Voluntary Actions Act (H.R. 2520) introduced by Representatives Lazio (R-NY) and Dooley (D-CA) on July 14, 1999.

dollars per year, incurred almost exclusively on coal-fired generation.[19]

Q. What is the current status of these environmental proposals?

A. The fine particulate NAAQS was finalized in 1997.[20] Although currently the standard has been remanded to EPA, I assume that the issues will be resolved and the new standard will apply in the 2010 timeframe.[21]

EPA now is conducting a monitoring program to determine which regions do not attain the new fine particulate standard. It is expected that many areas in the eastern U.S. will be designated as non-attainment areas, requiring states to implement tough new controls on fine particulate precursors such as SO_2 and to a lesser extent, NO_x. The EPA regulatory impact analysis indicates that

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19 EPA estimates that the "National PM 2.5 Strategy" would cost $2.6 billion per year in 2010 (1990 dollars). See *The New Environmental Drivers: Challenges to Fossil Generation Planning and Investment* (EPRI, 1998), pp. 4-18 – 4-19. In the *Mercury Study Report to Congress* (December 1997), EPA estimates that mercury controls could cost coal-fired utility boilers $5 billion per year. See Table 4-2 in *Volume I: Executive Summary*, p. 4-10. In a more recent study that examined combined emission control strategies, EPA estimated that a 50 percent reduction in SO_2 emissions would cost $2.5 billion per year (1990$) and a 70 percent reduction in mercury would cost $1.8 billion per year (1990$) by 2010 when implemented together. See *Analysis of Emission Reduction Options for the Electric Power Industry* (EPA Office of Air and Radiation), March 1999, Exhibits 3-19, 4-4 and 4-9.

20 *National Ambient Air Quality Standard for Particulate Matter; Final Rule.* 40 CFR Part 50, Federal Register, Vol. 62, No. 138, July 18,1997.

21 On May 14, 1999, the D.C. Circuit Court issued an opinion questioning the constitutionality of the Clean Air Act Authority to review and revise the NAAQS, and remanded the standard back to EPA. Under the court decision, EPA must construct a more determinate principle for promulgating new NAAQS, a burden that EPA may meet. On October 29,1999, EPA lost an appeal to the Circuit Court but is likely to take the case to the U.S. Supreme Court. This decision also remanded the new eight-

roughly 61,000 MW of coal-fired capacity will have to retrofit with scrubbers in the 2005 to 2010 time period to achieve the standard, with almost 35,000 MW installing scrubbers by 2005.[22] Exhibit JMS-4 shows recent estimates of retrofit scrubber costs from EPA and EIA. In terms of levelized costs, scrubbers add between \$5.45/MWh to \$9.07/MWh (\$1999) on a 500 MW plant.[23]

The mercury issue currently is under consideration for regulatory action, with a regulatory determination due in late 2000. Should EPA conclude that regulation is warranted, EPA probably will impose technology requirements on coal-fired boilers. Control technologies such as activated carbon injection and carbon filter beds can remove up to 90 percent of mercury emissions, but estimates of the costs of these emerging technologies vary widely. Exhibit JMS-5 shows levelized costs of selected mercury controls on coal-fired power plants, ranging from \$0.45/MWh to \$6.27/MWh (1999 dollars).

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hour ozone standard. However, the SIP Call and Section 126 petitions cited earlier are based primarily on the current one-hour ozone standard.

22 *Regulatory Impact Analysis for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule*. EPA (July 1997), Appendix H, "Economic Impact Analysis Supporting Information," Table H-3, Section 10.

23 Cost figures cited are direct costs only, and do not reflect savings in SO_2 allowance costs or potential fuel cost savings. Implementation of a $PM_{2.5}$ program could decrease the market price of allowances (if EPA mandates scrubbers on specific units) or could raise allowance prices (if EPA tightens the Phase II allowance "cap").

Exhibit JMS-6 compares illustrative cost impacts of fine particulate and mercury regulations to the \$10/ton CO_2 allowance price. Several points are worth noting. First, some coal-fired plants could incur higher levelized costs under a scenario of SO_2 fine particulate and mercury controls than under my assumed CO_2 adder. Second, the dispatch price of coal, oil and natural gas units would increase by the full amount of the assumed CO_2 adder, thereby increasing electricity prices. In contrast, the fine particulate and mercury requirements would have no impact on the cost of natural gas generation, and only the variable control costs of coal units would be included in the dispatch prices. As a consequence, in some cases, coal-fired power plants could be worse off under the additional fine particulate and mercury controls than under the assumed CO_2 policy.

Q. Are there other potential environmental programs?

A. Yes. Rules to address visibility (regional haze),[24] additional pressure to reduce SO_2 arising from acid rain concerns[25] and a lawsuit challenging EPA to tighten the current health-based National

[24] Final Rule Issued April 22, 1999, published in the Federal Register on July 1, 1999, at 64 FR 35714.

[25] Most recently, on February 9, 1999, Representative Sweeny introduced H.R. 657, the "Acid Deposition Control Act" that would cut the Phase II SO_2 allowance allocation by half in 2005. This is identical to provisions in H.R. 25, introduced by Representative Boehlert on January 6, 1999, and S. 172 introduced by Senators Moynihan, Schumer and Lieberman on January 19, 1999. See "Congress Takes New Interest in Passing Acid Rain Legislation," *Inside EPA*, May 28, 1999.

Ambient Air Quality Standard for SO_2 also add impetus for additional controls in the 2005 to 2010 timeframe.[26] EPA also has pursued a strategy to change the rules by which utilities would be subject to "New Source Review" (NSR) when undertaking investments to maintain and upgrade existing coal-fired plants. Beginning with a proposed rulemaking issued in 1996, through a series of discussions with several utilities over the past year, EPA is attempting to impose strict air pollution control requirements on older plants when they undergo certain types of modifications. Plants subject to the requirements would have to retrofit equipment to control emissions of NO_x, SO_2 and particulate matter. In addition to the NSR negotiations, EPA initiated enforcement actions against seven major Midwestern and Southeastern utilities and the Tennessee Valley Authority on November 3, 1999, for alleged past violations of the existing NSR policy. These enforcement actions reinforce my conclusion that EPA has targeted existing coal-fired generation for additional regulatory action.

Q. What is likely to be the overall impact of future environmental regulations?

[26] "National Ambient Air Quality Standards for Sulfur Oxides (Sulfur Dioxide); Intervention Level Program," *Federal Register*, Volume 63, No. 86 (May 5, 1998), pp. 24782-24784. See also *Electricity Daily*, June 11, 1998, "EPA Looks at New SO_2 Ambient Air Standards," p. 1-2.

A. It is uncertain how these environmental programs will be implemented, but it certainly is likely, and reasonable to assume, that some combination of new environmental controls will be required in the next decade. I believe that the most plausible case includes the SIP Call proposal for NO_x and other environmental requirements at least equivalent in cost to a $10 per ton price on CO_2 emissions. I conclude that my assumption to include the impact of CO2 controls using a $10/ton CO2 adder serves as a conservative estimate of the impact of a potential range of further environmental regulations on CG&E's coal-fired plants.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

JAMES M. SPEYER **Senior Vice President**

SUMMARY

James M. Speyer is the head of PHB Hagler Bailly's electric utility practice and an expert in the strategic analysis of energy and environmental issues, particularly those affecting the coal and electric utility industries. Mr. Speyer has provided expert testimony before Congress, state public utility commissions and state and federal courts on energy, economic and environmental issues.

Mr. Speyer's current work involves consulting to electric utility senior management on issues relating to the restructuring of the U.S. electric utility industry. Mr. Speyer also has been involved in the evaluation of the economic impact of the Clean Air Act on the coal and electric utility industries since the early 1970s, and has worked with a number of utilities to develop their acid rain compliance plans to meet the Clean Air Act Amendments of 1990. In addition, Mr. Speyer has provided strategic and economic advice to firms involved in the independent power markets. These assignments have included evaluation of potential market opportunities as well as evaluation of power purchase contracts and expert testimony.

ELECTRIC UTILITY AND OTHER ENERGY

Mr. Speyer's electric utility work spans all the interrelated facets of strategic planning, electric utility fuel price forecasting, supply planning and environmental control.

- For electric utilities, advised senior management on alternative strategies, including mergers and acquisitions, to adapt to the ongoing restructuring of the U.S. electric utility industry.
- For electric utilities, analyzed the financial and economic impacts of alternative strategies for nuclear power plants.
- For an electric utility, testified before the Pennsylvania PUC and West Virginia PSC, and submitted testimony to the Maryland PSC on projected fuel prices and costs to comply with environmental regulations.
- In arbitration regarding damages for alleged breach of contract between Bonneville Power Administration and Tenaska Washington Partners, Inc., provided expert testimony concerning key aspects of the damages claim. Analysis included forecasts of electricity and gas prices, valuation of a potential renegotiated gas contract and

valuation of the project after expiration of the power purchase agreement.

- For Bonneville Power Administration, assessed the potential stranded cost due to restructuring of the electric utility industry.
- For a nuclear industry liability case, prepared expert report and served as the expert on damages.
- For electric utilities, evaluated the economics of life extending coal-fired boilers versus alternative strategies, including converting to natural gas.
- For an electric utility, testified before the Indiana PUC on the issue of reasonableness of the fuel prices used by Public Service of Indiana in its acid rain compliance plan.
- For an electric utility, analyzed the impact of acid rain legislation on the economics of nuclear versus coal-fired power plants.

INDEPENDENT POWER MARKETS

Mr. Speyer's work in the independent power market includes strategic and economic advice to non-utility generation firms. Mr. Speyer has been retained by both defendants and plaintiffs to provide expert testimony on economic damages and other issues in litigation cases related to the non-utility generation industry. He also has assisted law firms in litigation concerning non-utility power plants that were already constructed and in operation as well as power plants that never were completed.

- On behalf of two non-utility generators in an antitrust suit against a large electric utility, provided an expert report on the manner in which the utility calculated its avoided costs, mitigation issues and the calculation of damages.
- For a potential cogeneration project host and steam user in a breach of contract suit against the project developer, presented testimony as a damages expert during trial.
- During regulatory proceedings related to the efforts of an independent power company to negotiate a power sales contract with the utility, testified on projected prices for low-sulfur coal.
- For an international independent power company, analyzed the financial feasibility of constructing and operating coal and wind power plants in the United States and several countries, including India.
- For an IPP, evaluated future electricity prices in the Northeast.

COAL

Mr. Speyer has been an important contributor to numerous projects involving detailed examination of coal supply and demand. This work has included acquisition and investment opportunities, marketing studies, fuel procurement studies, contract litigation and analyses of the economic and financial impacts of energy and environmental regulations.

- For coal producers, estimated coal prices for low- and high-sulfur coal and assessed the market potential for specific coal properties.
- For coal consumers, developed procurement strategies (including negotiation of coal contracts), developed coal price forecasts and estimated the sensitivity of these prices to economic and policy uncertainties.
- For both coal companies and utilities, assisted in calculation of damages related to coal contract disputes.
- For a client analyzing coal export markets, examined steam and metallurgical coal demand in the major consuming countries and production possibilities in the major exporting countries.

ENVIRONMENTAL ISSUES

- For a number of electric utilities, developed least-cost strategies to comply with the Clean Air Act's acid rain provisions, including development of clean coal technologies and the purchase and/or sale of emission allowances for sulfur dioxide.
- For an association of industrial companies and trade associations, analyzed the economic and environmental effects of alternative climate change policies.
- For industrial companies, developed strategies to capitalize on market opportunities related to the Clean Air Act's acid rain provisions, including development of clean coal technologies and the purchase and/or sale of emission allowances for sulfur dioxide.
- For the federal government, analyzed the financial and environmental impacts of energy and environmental regulations on the electric utility and coal industries.

WORK EXPERIENCE PRIOR TO PHB

Before joining PHB, Mr. Speyer was a principal with ICF, Incorporated. He also served as a senior member on President Carter's White House Energy Staff and was involved in the preparation and analysis of the National Energy Plan of 1977. He has held the positions of Director of Coal and Utility Policy at the U.S. Department of Energy and Director of Energy Policy at the U.S. Environmental Protection Agency. From 1968 to 1970, Mr. Speyer was a Peace Corps volunteer, working on sanitation issues in Venezuela.

EDUCATION, HONORS AND AWARDS

Mr. Speyer received a B.S. degree in Industrial Engineering from the University of Michigan in 1967, and an M.P.A. degree in Economics and Public Policy from Princeton University in 1972.

Mr. Speyer has also co-authored several articles and studies on energy and environmental topics, and has received awards for superior service from the Environmental Protection Agency.

EXHIBIT JMS-2
DELIVERED FUEL PRICE ASSUMPTIONS

COAL

First Table of Exhibit JMS-2 filed under seal.

NATURAL GAS

Monthly ECAR Natural Gas Prices ($99/mmBtu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001	2.89	3.09	2.53	2.24	2.22	2.27	2.12	1.94	1.99	2.24	2.40	3.01
2003	2.92	3.13	2.56	2.27	2.25	2.30	2.15	1.97	2.01	2.27	2.43	3.05
2008	3.11	3.32	2.72	2.41	2.39	2.44	2.28	2.09	2.14	2.41	2.58	3.24
2010	3.21	3.43	2.81	2.49	2.47	2.52	2.35	2.16	2.21	2.49	2.67	3.34

Annual Average Natural Gas Prices by Year and Region ($99/mmBtu)

Year	ECAR	MAIN	MAPP	NEPOOL	NYPP	PJM	SERC	SPP
2001	2.41	2.41	2.31	2.74	2.66	2.66	2.45	2.24
2003	2.44	2.44	2.34	2.77	2.69	2.69	2.48	2.27
2008	2.60	2.60	2.49	2.93	2.84	2.84	2.63	2.43
2010	2.68	2.68	2.57	3.01	2.93	2.93	2.72	2.51

FUEL OIL

Delivered No. 2 Fuel Oil Prices by Year and Region ($99/mmBtu)

Year	ECAR	MAIN	MAPP	NEPOOL	NYPP	PJM	SERC	SPP
2001	3.67	3.65	3.80	3.53	4.23	3.59	3.71	3.65
2003	3.92	3.89	4.07	3.79	4.49	3.83	3.95	3.91
2008	4.41	4.36	4.58	4.29	4.99	4.31	4.43	4.40
2010	4.56	4.51	4.74	4.45	5.14	4.46	4.58	4.55

Delivered No. 6 Fuel Oil Prices by Year and Region ($99/mmBtu)

Year	ECAR	MAIN	MAPP	NEPOOL	NYPP	PJM	SERC	SPP
2001	2.14	2.37	2.42	2.28	2.81	2.35	2.06	1.51
2003	2.30	2.53	2.57	2.44	2.97	2.51	2.22	1.66
2008	2.61	2.84	2.88	2.75	3.28	2.81	2.53	1.97
2010	2.70	2.93	2.98	2.84	3.37	2.91	2.62	2.07

EXHIBIT JMS-3
ASSUMPTIONS ON ENVIRONMENTAL COMPLIANCE COSTS

SO_2 and NO_X Environmental Adders

The following SO_2 and NO_X allowance prices were added to fuel prices in the most plausible scenario:

Allowance Prices (1999$/Ton)

Year	$/Ton SO_2	$/Ton NO_X	
		OTR Region	22-State SIP Call Region (Non-OTR)
2001	201	3,066	--
2003	236	3,577	3,577
2008	346	3,577	3,577
2010	402	3,577	3,577

CO_2 Fuel Adders under the $10/ton CO_2 Policy

The following costs were added to fossil fuels consumed in electric generation in the $10/ton CO_2 policy case:

Cost Adders for $10/ton CO_2

Fuel Type	Cost Adder (1999$/mmBtu)
Coal	1.06
Gas	0.59
Distillate Oil	0.83
Residual Oil	0.89

EXHIBIT JMS-4
REPRESENTATIVE SCRUBBER COSTS

Retrofit Scrubber Costs for 500 MW Unit[1] ($1999)			
	Levelized Capital & Fixed O&M ($/MWh)	Variable O&M ($/MWh)	Total Levelized Cost ($/MWh)[4]
EPA Low Estimate[2]	3.89	1.56	5.45
EPA High Estimate[2]	4.87	2.17	7.04
EIA Estimate[3]	6.70	2.37	9.07
AVERAGE	5.15	2.04	7.19

NOTES

[1] These estimates use a 11.9% fixed charge rate to annualize capital expenditures. Capital and Fixed O&M are levelized using an 80% capacity factor. Variable O&M includes a 2.1% energy penalty assessed at $25/MWh.

[2] EPA estimates derived from cost and performance parameters found in "Analyzing Electric Power Generation under the CAAA" (EPA , March 1998) Appendix A, p 8-9. Retrofit penalty of 1.1 is assessed on capital costs.

[3] EIA estimates are derived from *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990* (EIA, March 1994) Appendix D. Costs in 1992 dollars are converted to 1999 by GDP deflator factor of 1.149.

[4] Direct scrubber costs only. These figures do not reflect cost savings from the sale of SO_2 allowances or potential savings in fuel costs from the ability to substitute cheaper coal.

EXHIBIT JMS-5
REPRESENTATIVE MERCURY CONTROL COSTS

Cost of Mercury Controls[1] (1999$)			
Mercury Controls	**Existing Controls on Unit**	**Estimate Source**	**Total Cost ($/MWh)**
Activated Carbon (AC) Injection	Low Sulfur Coal ESP	EPA	2.05
		DOE	6.27
AC Injection, Spray Cooler	Low Sulfur Coal ESP	EPA	0.45
		DOE	2.46
AC Injection, Spray Cooler, Fabric Filter	Low Sulfur Coal ESP	EPA	1.61
		DOE	2.36
Carbon Filter Bed	Low Sulfur Coal ESP	EPA	3.02
Carbon Filter Bed	High Sulfur Coal ESP/FGD	EPA	3.50

NOTES

[1] Adapted from Tables B-14 and B-15 in *Mercury Study Report to Congress Volume VIII: An Evaluation of Mercury Control Technologies and Costs* (EPA-542/R-97-010, December 1997). These costs are for a 975 MW unit, and were reported in 1993 dollars which have been converted to 1999 dollars using the GDP deflator factor of 1.124.

EXHIBIT JMS-6
COMPARISON OF FINE PARTICULATE, MERCURY AND CO_2 CONTROL COSTS

Fine Particulate and Mercury Control Costs for Coal Units Compared with CO_2 Costs for Coal and Gas Units ($1999)	
CONTROL COST	**Total Cost ($/MWh)**
Fine Particulate Cost[1]	7.19
Mercury Control Cost[2]	3.50
Combined Fine Particulate and Mercury Cost[3]	10.69
$10/ton CO_2 Costs: Coal[4]	10.09
$10/ton CO_2 Costs: CCGT[5]	3.94

NOTES

1 Average scrubber costs from Exhibit JMS-4.

2 Carbon Filter Bed on high sulfur coal unit with ESP/FGD from Exhibit JMS-5. Figures were converted from 1993 dollars to 1999 dollars using 1.124 GDPdeflator.

3 Fine Particulate Cost plus Mercury Control Costs.

4 Assumed 9,500 Btu/kWh heat rate for existing coal plant. Assumed $10/ton adder in $1997 equals $10.22/ton in $1999.

5 Assumed 6,600 Btu/kWh heat rate for new natural gas-fired combined cycle plant. Assumed $10/ton adder in $1997 equals $10.22/ton in $1999.

CG&E EXHIBIT 19

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION	)	
OF THE CINCINNATI GAS & ELECTRIC	)	
COMPANY FOR APPROVAL OF ITS	)	CASE NO. 99-1658-EL ETP
ELECTRIC TRANSITION PLAN	)	

DIRECT TESTIMONY OF

DR. KENNETH GORDON

ON BEHALF OF

THE CINCINNATI GAS & ELECTRIC COMPANY

DIRECT TESTIMONY OF DR. KENNETH GORDON

QUALIFICATIONS, SUMMARY AND CONCLUSIONS

Q. Please state your name and business address.

A. My name is Dr. Kenneth Gordon. My business address is One Main Street, Cambridge, Massachusetts 02142.

Q. What is your current position?

A. I am a Senior Vice President of National Economic Research Associates, Inc. (NERA)

Q. Will you please summarize your education and professional qualifications?

A. I am an economist and former Chairman of the Maine Public Utilities Commission (Maine Commission) and the Massachusetts Department of Public Utilities (Mass. DPU). (The Mass. DPU is now known as the Massachusetts Department of Telecommunications and Energy.) A copy of my curriculum vitae is attached as Exhibit KG-1. I have been an economist since 1965, and I have been directly involved with developing and establishing regulatory policy at the federal and state levels since 1980, when I became an industry economist at the Federal Communications Commission (FCC).

I received my A.B. degree from Dartmouth College in 1960. I received my M.A. degree in 1963 and my Ph.D degree in 1973, both in economics, from the University of Chicago. I have taught applied microeconomics, industrial organization, and regulation (as well as other subjects) at Georgetown University, Northwestern University, University of Massachusetts at Amherst, and Smith College.

From 1980 to 1988, I was an industry economist at the FCC's Office of Plans and Policy, where I worked on a full range of regulatory issues, including telecommunications, cable, broadcast, and intellectual property rights. At the FCC, one of the major focuses of my work was activity aimed at introducing competition into communications markets.

Prior to joining NERA in November 1995, I chaired the Maine Commission (1988 to December 1992) and the Mass. DPU (January 1993 to October 1995). During my term as Chairman of the Mass. DPU, the DPU investigated and approved a price cap incentive regulation plan for NYNEX and also undertook a proceeding to examine interconnection and other issues related to the development of competition at all levels of telecommunications, including basic local service.

While I was its Chairman, the Mass. DPU issued a series of orders aimed at the reform of electric rate regulation, including revisions to integrated resource management procedures, the introduction of incentive regulation, the treatment of acquisition premiums in mergers and acquisitions, and the design of electric industry restructuring. I was very heavily involved in developing Massachusetts' plan to introduce competition in retail electric markets in that state and the concurrent efforts to establish practical policies to address stranded costs and other transitional issues that arise in restructuring the electric utility industry. While in Massachusetts, I co-chaired the Governor's task force on electricity competition.

While a regulator, I was active in the National Association of Regulatory Utility Commissioners (NARUC), serving on its Communications and Executive Committees. In 1992, I served as President of NARUC. I was also Chairman of the BellCore Advisory Committee and the New England Governor's Conference Power Planning Committee.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an independent evaluation, as an economist and former Chairman of two state regulatory agencies, of whether the Transition Plan, as proposed by The Cincinnati Gas & Electric Company (CG&E), viewed as a comprehensive whole, can: (a) lead to efficient competition where competitors compete based on forward-looking economic costs while also accommodating the legislature's shopping incentive target; and (b) address the legitimate market power issues that arise in implementing electric restructuring. I conclude that

CG&E's Transition Plan achieves these objectives in a satisfactory manner, given the constraints and challenges CG&E faces in implementing retail competition.

In addition, my testimony addresses an issue regarding the appropriate ratemaking treatment of the Gross Receipts Tax.

Q. What have you done to prepare this testimony?

A. I have reviewed Ohio's recently enacted electric restructuring bill. I have reviewed the Public Utility Commission of Ohio's (Commission's) rules on electric restructuring issues, CG&E's Transition Plan, and testimony of various CG&E witnesses (including, in some cases, supporting materials sponsored by those witnesses). More generally, I have reviewed recent developments on electric restructuring issues, such as trends in switching rates, in a number of states and countries. In surveying trends in other states and countries with respect to switching by customers, I have relied upon the studies and reports, usually from official publicly-available sources, that I found most useful, authoritative, and reliable.

In addition to the above, I attempt to remain current with writings and significant regulatory and legislative developments and issues relating to electric restructuring. In preparing the policy recommendations that I support in my testimony, I have relied upon, and cited in my testimony, those treatises, studies, and reports that I believe are the most useful, authoritative, and reliable.

Q. Please summarize the conclusions that you have drawn, based upon your review of CG&E's Transition Plan.

A. I have drawn the following primary conclusions:

1. From an economic standpoint, it is very important that restructuring policies be implemented in ways that lead to efficient competition. CG&E should therefore have the opportunity to meet the legislation's 20% switching rate target (by customer class) without the introduction of policy or pricing schemes that artificially tilt the competitive playing field. Shopping incentives should not be used, at least initially, to artificially boost electricity users' incentive to switch. Trends in other jurisdictions and the specific circumstances in Ohio, including consumers' expressed willingness to switch, the availability of aggregation in Ohio, experience with retail competition in natural gas, and the desire for green power and other value-added services support the conclusion that shopping incentives are not needed. The failure to achieve efficient competition as a result of the imposition of shopping incentives is likely to be costly to consumers.

2. The safeguards and structures provided in CG&E's Transition Plan are more than sufficient to prevent CG&E from being able to exercise market power.

Q. Please describe how your testimony will be organized.

A. My testimony will:

1. Describe the economic and public policy principles that I rely upon in evaluating CG&E's Transition Plan.
2. Explain why the Transition Plan must provide a level playing field that allows competitors to compete efficiently, based on forward-looking economic costs.
3. Evaluate whether or not the legislature's switching target, as set forth in The Electric Restructuring Bill, R. C. 4928.40, can be met without the use of shopping incentives.
4. Evaluate whether or not CG&E will be able to exploit market power if the Transition Plan is approved.
5. Discuss an additional tax and ratemaking issue concerning the ratemaking treatment of the Gross Receipts Tax.

PUBLIC POLICY ISSUES IN IMPLEMENTING ELECTRIC RESTRUCTURING

Q. Why is efficient competition needed in retail electricity markets?

A. Electric restructuring, undertaken in order to promote a more efficient electricity industry, should be implemented in ways that lead to efficient competition. Efficient competition is present when all competitors are free to succeed or fail in the marketplace on the basis of their relative efficiencies and advantages in serving consumers. Reliance on competitive markets is based on the principle that firms that can produce most efficiently, based on forward-looking costs, and bring the most value to consumers, should (and will) prevail. Efficient competition leads to production at the lowest achievable costs, which is a socially desirable outcome that results in an efficient use of society's resources and provides consumers with the products they desire at the lowest possible prices.

Efficient—and dynamic—competition in many branches of the American economy has led to the evolution of new products to meet market demand, caused industries to emerge, expand, and contract, and allowed new and innovative technologies to develop to meet the needs of consumers and businesses. Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes and procedures—that meets market demand. Dynamic competition in electricity markets can play an important role in further enhancing consumer welfare and economic progress in an important sector of the American economy. Because competition in electric commodity markets can encourage economic efficiency, reduce costs to consumers, increase the quality of electricity service, and thereby increase consumer and social welfare, regulators are implementing restructuring of the electric industry to accommodate competition in electric generation commodity and retail markets. At the same time, regulators will continue to regulate the natural monopoly aspects of the transmission and distribution network.

Policy makers and regulators must develop an appropriate regulatory framework before retail competition unfolds. As retail competition is introduced, the competitive playing-field should be fully open to entry by potential competitors but should not be tilted in ways that artificially favor entry by less-efficient competitors. Just as Olympic athletes compete with each other in Olympic events, with the winner being the competitor with the best performance in that event, competitors in retail generation markets should compete based on forward-looking economic costs absent of artificial handicaps or special advantages. The competitive contest should not be designed to favor or disfavor any competitor in an artificial or distorted way.

Competitors will bring different skills and strengths to the market contest; so long as the market is open to competitors and customers have the ability to choose for themselves, there is nothing unfair or anti-competitive about this. There is simply no legitimate need to give special preferences or protections to new entrants in newly open electricity markets. (Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness* (East Lansing, Michigan: MSU Institute of Public Utilities and Network Industries, 1998), p. 20.)

The long-term danger of policies that accommodate—or even encourage—inefficient entry is that the new entrants—once they have entered a market—will have strong incentives to maintain the *status quo* in order to protect their economic interests. Once entry occurs, it will be difficult for policymakers to change the rules of the game to become more efficient. This outcome is a major reason why it is important to introduce retail competition at the outset in ways that are consistent with efficient competition. (Steven G. Breyer, "Antitrust, Deregulation, and the Newly Liberated Marketplace," 75 *California Law Review* 1005 (1987).)

GUIDING PRINCIPLES FOR EVALUATING ELECTRIC RESTRUCTURING TRANSITION PLANS

Q. What principles will you use to guide your evaluation of CG&E's Transition Plan?

A. The introduction of competition should be based on sound economic and public policy principles. I believe that the following principles should be followed when introducing retail competition:

1. *Consumer benefits should be the criterion.* The appropriate test for competition policies is whether or not they lead to benefits—such as lower prices to consumers, better quality and reliability, service innovations, etc.—to consumers. The focus should always be on whether or not consumers experience real economic benefits from a particular policy.

2. *Consumer sovereignty.* Transactions for the retail sale of electricity should be *voluntary*—consumers' ability to choose their providers of generation services should not be restricted by policy makers or regulators. Retail competition breaks the mandatory purchasing agent role of the electric utility by allowing all customers to select their own providers of generation commodity and retail sale services. There should be no mandatory agent-principal relationships in the generation and retail sale of electricity. Rather, consumers should be able to choose for themselves their providers of retail generation services.

3. *Provide openness and choice.* Electric restructuring, properly viewed, provides *open* entry into competitive markets and allows consumers to *choose* for themselves

their providers of retail generation services. This combination of open entry for suppliers and choice for customers provides the benefits of competitive markets (*e.g.*, efficient resource allocation, accurate price signals, and incentives for innovation) and would limit competitors' ability to exercise market power. Regulators should ensure that entry into competitive generation and retail commodity markets is open in order to provide choice for consumers. This does not mean that entry into markets will be costless or easy, but rather that all actual competitors, incumbents and new entrants alike, will have made (and potential competitors could make) the investments and commitments necessary for them to compete in the market.

4. *Competitive Neutrality.* For competition in generation commodity and retail sale markets to be competitively neutral (*i.e.*, comparable, and nondiscriminatory), competitors must be free to succeed or fail in the marketplace on the basis of their relative efficiency in serving the needs of consumers. The competitive marketplace should not be tilted to artificially support less efficient competitors. Doing so would contradict the basic purpose of substituting competition for regulation.

5. *Transmission and Distribution (T&D) service must accommodate efficient competition in generation commodity and retail sale markets.* T&D utilities must provide open, nondiscriminatory and comparable service to all electricity consumers and suppliers. Operation of the T&D system should be transparent—that is, access to information on the operation of the T&D systems should be available to competitors and consumers at low cost.

6. *Appropriately address transition issues.* Society has a responsibility to meet past regulatory commitments. Further, allowing recovery of legitimate and prudent transition costs can provide benefits to consumers by accelerating the pace of change to efficient competition. This can be achieved through the use of competitively neutral and unbypassable mechanisms.

7. *Maintain safety, adequacy and reliability.* Given the importance of electricity in modern life, the safety, adequacy and reliability of electricity service must not be compromised.

8. *Regulation of the T&D system should support efficient competition.* Regulation of the T&D providers should: (a) support efficient competition in competitive generation and retail sale markets; (b) accommodate innovation; (c) avoid

cross-subsidies between regulated and competitive products and services; (d) provide sufficient unbundling of electric products and services; and (e) support the efficient provision of T&D services through the use of ratemaking policies that provide the utility with incentives to improve its operating efficiency while also allowing it an opportunity to recover its costs (including the cost of capital).

9. *Recognize customer information and search costs without disrupting the market discovery process.* Policy makers can appropriately establish policies that recognize the transaction costs that end-use customers bear for searching for, selecting, and monitoring their electricity provider through: (a) reasonable disclosure requirements; (b) well-targeted and cost-effective consumer education and information programs; and (c) appropriate enforcement of consumer protection requirements. These public policy initiatives would have costs as well as benefits. While retail competitors and electricity users are likely to bear most of these costs, taxpayers and customers of the T&D utility will likely bear some of these costs as well. Regulators should carefully consider the allocation of these costs when implementing electric restructuring rules.

10. *The pricing of standard offer service should not artificially encourage or discourage customers to switch.* Because some consumers may prefer to reduce their search costs by taking a service that is comparable to traditional electric utility service, policy makers can ensure that some form of appropriately-priced standard offer service is available. Thus, it might be reasonable for policy makers to provide a standard offer service to customers that choose not to choose—but only if this service does not distort the competitive process in the market and unduly raise the administrative cost of regulation. Regulators, however, must take care to avoid unnecessary and inefficient distortions in the workings of competitive markets and inordinately high administrative costs.

These principles, if followed, can lead, over time, to the achievement of efficient retail competition, which will benefit consumers (through the provision of the electricity services that they desire at the lowest possible cost) and society generally (through the efficient allocation and use of society's scarce resources). Given the importance of electric utility infrastructure in modern-day American life, efficient competition in retail electricity markets could enhance the ability of Ohio consumers and businesses to thrive in the global marketplace.

Q. Are these guiding principles consistent with Ohio's retail electric competition policy?

A. Based upon my years of experience as an economist and as a former Chairman of utility regulatory agencies in two states, I conclude that these principles are consistent with the nine policy goals that are stated in the Electric Restructuring Bill, R. C. 4928.02. I would hasten to add, however, that I am not a lawyer and therefore cannot answer this question definitively from a legal standpoint.

OVERALL PERSPECTIVE AND THEMES

Q. Before reviewing CG&E's Transition Plan on an issue-by-issue basis, are there any overall observations that you would like to make?

A. Yes. I would like to emphasize four basic points that I believe are particularly important in evaluating transition plans.

First, it is important to introduce retail competition appropriately at the outset. Competition in generation commodity and retail markets is needed because competitive markets can more efficiently discover and meet the needs of consumers than can policy makers. Regulators must allow competitors to determine for themselves the products that they will offer to consumers and allow consumers to sift through those products and to choose for themselves. Only when the invisible hand provided by the market discovery process is allowed to operate naturally, can the competitive process provide the market information—and the necessary incentives—which consumers and suppliers need to make their individual decisions.

Regulators must focus on introducing *efficient* competition in retail electricity markets. If competition is efficient, competitors would compete based on relative efficiencies in meeting the needs of customers. Low-cost competitors that provide products that consumers value would thrive in this environment, while less efficient competitors would have strong incentives to search for ways to improve their efficiency and the value of their service offerings in order to be more competitive.

Second, once the basic institutional and regulatory structures and rules that are needed to support efficient competition in retail electricity markets have been put into place, regulators must, except for maintaining the basic structure, step back and let competitive markets do the job. The temptations to intervene in the workings of competitive markets will be substantial—unsuccessful competitors, in particular, will be quick to request that regulators relieve them from the rigors of competitive markets. In dealing with these requests, regulators will again need to continue to focus on supporting efficient competition in retail electricity markets.

Third, remember the rule of unintended consequences. In electric restructuring proceedings, many of the issues are interrelated and, therefore, it is important to ensure that a restructuring plan, as a comprehensive whole, is well integrated and balanced. In evaluating transition plans, regulators may find it helpful to consider Lincoln's admonition that "If we could first know *where* we are, and *whither* we are tending, we could then better judge *what* to do, and *how* to do it." (Garry Wills, *Lincoln at Gettysburg: The Words That Remade America* (New York: Simon and Schuster, 1992), p. 161.)

Distortions in one aspect of electric restructuring will inevitably have impacts on other areas. Therefore, in evaluating restructuring plans, it is important to keep an eye on identifying perverse and unintended consequences and then searching for, and correcting, the root cause. In short, any government agency that sets out to repair one defect must take care lest the repair cause serious damage elsewhere.

Fourth, efficiency and market power considerations must be balanced. In introducing electric restructuring, it is important, of course, that T&D operators provide open, nondiscriminatory, comparable, and competitively-neutral T&D services to all competitors in wholesale or retail electricity markets. In addressing market power issues, however, it is important that legitimate efficiencies of all competitors, including incumbents, be brought to the marketplace and not be foregone unnecessarily. Regulatory policies must protect retail consumers against the possible exercise of market power by a utility and its affiliate without giving up legitimate efficiencies that benefit consumers. Excessive restrictions on the ability of an incumbent utility or its affiliate to compete, could prevent the realization of efficiencies (*e.g.*, economies of scale and scope) that would benefit retail electricity consumers and society as a whole and could weaken competitive forces by limiting the ability of a potentially efficient competitor to compete in the market.

While electric restructuring undoubtedly raises a number of important and very challenging issues for regulators, these issues are manageable as long as regulatory decisions are solidly supported by sound economic and public policy principles. Electric restructuring re-shuffles the deck, but the basic economic principles that have been used in regulating utilities remain the same. These economic principles should guide regulators as they proceed to implement electric restructuring.

SHOPPING INCENTIVE PLAN

Q. What conclusions have you reached regarding the use of shopping incentives?

A. I recommend that no shopping incentive be used initially and, possibly, ever. Rather, regulators should set CG&E's unbundled rates based on correct economic principles. If the resulting prices result in some modest level of potential savings or added value being available to consumers who switch, sufficient customers could reasonably be expected to switch without a shopping incentive.

Industrial and commercial customers are generally well aware of their energy options, costs and opportunities and have relatively low transaction costs regarding switching. These customers are likely to be very responsive to taking advantage of customer choice. Therefore, these customers are not likely to need artificial incentives to shop. The available evidence strongly suggests that larger-volume customers do not need to be artificially induced to switch. Thus, the market itself is likely to provide industrial and commercial customers with sufficient inducements to seek out and consider alternatives to traditional utility service.

Residential customers may not have as strong an economic incentive to shop and likely have higher search, information, and other transaction costs that could tend to slow switching rates somewhat. But four considerations in Ohio suggest that shopping incentives may not be needed. First, significant opportunities are available in Ohio for aggregation and/or marketing programs that would tend to reduce residential customers' transaction costs and increase the potential benefits to consumers from switching. Voluntary municipal aggregation can provide a significant amount of switching by residential customers, in ways that could reduce customers' transaction costs and increase potential savings. Second, a significant percentage of residential consumers in CG&E's service territory have already indicated an interest in switching, so long as some modest level of savings or added value can be achieved. Third, the presence of natural gas competition in CG&E's service territory (since November 1997) will tend to provide opportunities for residential customers to switch to a single provider of gas and electricity retail services. Fourth, residential customers have expressed interest in green power, and there may be other value-added services that could be developed to appeal to residential customers. These considerations, along with the basic consideration that some residential customers will save money from switching simply because their costs to serve are lower than the average for their rate class, suggest that sufficient switching by residential customers could occur without the need for an artificial stimulus via shopping incentives.

I recommend that the prices of CG&E's unbundled rate components and the market price of generation (*i.e.*, the shopping credit) first be set based on correct economic principles. Then, during the initial period of competition, trends regarding marketing practices and switching rates can be monitored to determine whether new policy approaches are necessary in order to meet the 20 % switching target set by the legislature. During this period the Commission could focus on consumer information and education and other measures aimed at reducing customers' search, information, and other transaction costs. Allowing as many customers as possible to voluntarily switch without an artificial subsidy is critically important in order to reduce the economic wastefulness and distorting impact of the shopping incentive approach.

Q. Please summarize the Ohio Electric Restructuring Bill's switching target.

A. In Ohio, a legislative target (not a mandate) provides for "a twenty percent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003" (R. C. 4928.40). The Commission can establish shopping incentives by customer class to meet this target.

Q. As an economist and former regulator, please comment on this provision.

A. The switching target could result in inefficient competition by inducing entry by less efficient producers. If this result should prove to be the case, this target is likely to be wasteful of society's scarce resources and costly for consumers. I believe that when competition is introduced in industries that have previously been regulated as natural monopolies, regulators should strive to introduce full customer choice and efficient competition, where customers are confronted with the true alternatives in the market and where competitors compete based on forward-looking costs. Efficient competition, undistorted by regulation, improves the efficiency with which services are provided, by weeding high-cost firms out of the market and exerting pressures on the survivors, including pressures to improve the quality of their offerings and to be innovative in developing and offering new services and service combinations.

If less efficient producers enter the market as a result of the subsidy that a shopping incentive would provide, the incumbent provider would face less competitive pressure to lower its costs, which would reduce productive efficiency. Neither the higher-cost entrants nor the incumbent provider would operate at the minimum efficient scale that is required for competitive success in the (undistorted) marketplace. This would result in higher prices than would otherwise be the case, which would result in the loss of allocative efficiency. A shopping-incentive subsidy would thus result in a less efficient market environment, which would raise costs for consumers and misallocate society's resources.

Q. Do you believe that tilting the competitive playing field is appropriate?

A. No. Regulators should not attempt to artificially jump-start or manage the competitive process by tilting the competitive playing field (*e.g.*, by providing special benefits to new entrants or by handicapping the incumbent utility). Competitive markets should instead be allowed to develop based on evolving supply and demand conditions in the market, with government's role focusing primarily on facilitating open entry into these markets. This can be done primarily by ensuring that distribution delivery services are provided on an open, nondiscriminatory, comparable, and competitively neutral basis to all competitors in the competitive generation and retail sale markets.

While jump-starting the market could certainly provide tangible benefits to new entrants, there is reason to be skeptical about the benefits of such policies for consumers. First, such intervention is likely to actually *reduce* the effectiveness of competition, and thus would tend to raise the prices paid by consumers. Second, and most importantly, many of these plans are fundamentally inconsistent with the principle of competitive neutrality. Consumers (including residential and small commercial customers) should be able to choose their provider of retail electricity services for themselves, undistorted by subsidies that favor some competitors over others.

An infant industry rationale has sometimes been used to advocate the shackling of incumbents for the sake of promoting new entrants. However, economists who have studied infant industry policies are generally skeptical that they provide lasting benefits. (*Against the Tide: An Intellectual History of Free Trade,* Douglas A. Irwin, Princeton University Press, 1996, especially Chapter 8: "Mill and the Infant Industry Argument," pp. 116-137.) The danger always exists that any such entrants are inefficient and only viable as a result of such infant industry subsidies. The infants can refuse to grow up, as it were, relying on subsidies forever. In any case, many of the companies already active in markets in other states cannot plausibly be considered infants in any aspect of the energy industry.

Q. Despite your concerns, the legislature has established this switching target. How should the Commission go about meeting this target?

A. I strongly recommend that the Commission implement this requirement in ways that are as least wasteful and distortional as possible. To the greatest extent possible, the Commission should develop pricing rules that are consistent with the principles of competitive parity that should guide regulators as they strive to introduce efficient competition. (Alfred E. Kahn and William E. Taylor, "The Pricing of Inputs Sold to Competitors: A Comment," 11 *Yale J. on Reg.*, p. 225-240.) Subsidies, via shopping incentives, should only be imposed after actual experience indicates that the switching target is not likely to be met through voluntary switching by customers.

PRINCIPLES OF COMPETITIVE PARITY FOR EFFICIENT COMPETITION

Q. Please explain the approach that the Electric Restructuring Bill uses to establish prices for unbundled services.

A. Briefly, the Electric Restructuring Bill requires that unbundled rates for transmission, distribution, generation, and any other unbundled components be designed to reflect the "cost attributable to the particular service as reflected in the utility's schedule of rates and charges in effect on the effective date of this section." (R. C. 4928.34). The Legislation also requires that the total of all unbundled components in the rate unbundling plan be capped at the total level of all of the rates and charges that were in effect on the day prior to the effective date of the Legislation. To bridge these two requirements, the unbundled components for retail electric generation service (G) is treated as a residual or plug figure. G is made up of three components: (a) generation transition costs (GTC), which is designed to collect certain above-market generation-related transition costs; (b) regulatory transition costs (RTC), which is designed to collect generation-related regulatory assets; and (c) the market price of electricity. The GTC and the RTC would be recovered through a competitive transition charge (CTC), as set forth in CG&E's Application for Receipt of Transition Revenues.

The market price of electricity plays a critically important role in determining the retail generation credit. The retail generation credit is sometimes called a shopping credit. (Some observers view the term "shopping credit" as a pejorative term signaling a retail generation credit that has been set at an artificially high level in order to artificially induce customers to switch.) The term, retail generation credit, is a more neutral term. The retail generation credit that customers receive if they select a competitive retail electricity provider (and thus discontinue taking those services from the utility) should equal the market cost of electricity plus the incremental costs to the utility that are avoided as a result of no longer providing retailing services to those customers that switch to an alternative provider. From the standpoint of a departing customer, the retail generation credit would be viewed as providing a credit for electricity costs that the customer avoids by taking service from a competitive provider (including those incremental retailing costs that are avoided by the utility because it no longer provides retailing services to the customer). This credit would provide an assurance that the customer does not pay for some services twice. Under CG&E's approach, the retail generation credit would be updated on a quarterly basis, which would provide a sufficiently up-to-date retail generation credit.

Q. Can these requirements be implemented in ways that are consistent with efficient competition?

A. Yes, but it is clear that it will not be easy.

Correctly setting the level of the retail generation credit is critically important in order to provide efficient competition in Ohio's retail electricity market. From the standpoint of competitors in the retail market, the retail generation credit is the price that competitors will compete against. If this price is set in a way that provides competitive parity, there is a strong assurance that the outcome of the competition will be determined exclusively by the relative efficiency of the rivals in performing the retail functions that they are contesting. This can provide first-order productive efficiency—where production is distributed among the competitors such that total cost is minimized.

Because the retail generation credit is based primarily on the market price of electricity, it is very important that that market price be set in an economically appropriate manner. If that figure is set at an artificially high level, as has happened in some states, the result will be to limit CG&E's ability to recover its above-market transition costs and to distort the competitive process in the provision of retail electricity by providing a subsidy to new entrants. CG&E's approach addresses these issues by providing that the retail generation credit is up-dated on a quarterly basis.

Q. Will setting the retail generation credit in this way tend to lead to efficient entry in the competitive marketplace?

A. Yes. When the retail generation credit is based on the costs that the utility avoids as a result of no longer providing retail electric service to a customer, then the retail generation credit would promote efficient competition. The generation component of the retail generation credit would reflect the going-forward cost of generation in the market that the utility would avoid by taking service from another provider. Other retailers would incur the same sorts of costs to serve customers. Thus, if a competitive retailer can find cheaper sources for wholesale power than the utility or can contract more efficiently, it can offer lower-priced service. Similarly, the retail component of the retail generation credit would reflect the utility's efficiency in minimizing the overhead costs it incurs to provide retail service. If the utility is inefficient in managing these costs, relative to competitive retailers, retailers will be able to offer lower priced services because they do a better job at managing their margin.

The principles of competitive parity require the use of the utility's margin—the costs that the utility avoids by no longer providing retail services to customers that switch—because this is the cost that is avoided when a customer switches to a competitive provider. While economically correct, setting the retail generation credit in this way can present a competitive challenge for retailers. Some retailers may not be able to provide basic service to customers as cheaply as the incumbent utility. On the other hand, many of the new entrants into the competitive marketplace are national firms that will bring competitive strengths, and their own economies of scale and scope, to their business activities in the State of Ohio.

Q. Would retail competition be stifled if the utility emerges as the most efficient provider of basic electric service?

A. No, but pricing standard offer or default service at an artificially low price could have the effect of hindering the development of retail competition. As with any other competitive market, a retailer will have a role to play as the middleman between the wholesale market and end-use customers if it can provide a lower price or better service than customers could otherwise attain on their own. Retailers must provide something of value to warrant their position in the supply chain. But the standard offer or default service that they compete against must be priced at an appropriate level.

The role of efficient retail competition is to create benefits for end-use customers. Pricing standard service as I have suggested allows retailers to enter and profit in the market if and only if they are able to deliver benefits in at least one of two forms. The retailer must either: (a) be more efficient than the utility in the provision of retail electricity service and thus offer a lower price to gain market share; or (b) innovate to introduce value-added products and services that inspire switching because customers demand these products and are willing to pay a premium to receive them. In the first approach, the utility's *price* for standard service becomes the benchmark to beat. In the second retailer strategy, the utility's basic *service* sets the minimum standard to be improved upon.

Q. **What would be the effect of a too-high or a too-low retail generation credit?**

A. If the retail generation credit is set artificially high, the presence of the artificially high retail generation credit could act as a price umbrella that would tend to reduce pressure on other competitors to pass through reductions in electricity prices to end-use customers. This is the case in Pennsylvania, where the retail generation credit (commonly referred to as the "shopping credit" in that state) was set at levels that are much higher than economic efficiency would dictate. In Pennsylvania, in order to benefit from competition, a customer has to go out and find another supplier in order to receive the benefit of an artificially high shopping credit. High switching rates have been achieved but there is no basis for believing that this process has led to efficient competition.

In testimony before the New Jersey legislature, my colleague at NERA, Sally Hunt, argued that Pennsylvania "offered a shopping credit of perhaps 50% more than the correct amount" and that this subsidy to entrants is wasteful and unfair. (Sally S. Hunt, Testimony before the New Jersey Senate Assembly, Policy and Regulatory Oversight Committee, November 20, 1998.) New Jersey's electric restructuring legislation allows the New Jersey Board of Public Utilities (BPU) to set the shopping credit on a utility-by-utility basis. In approving a settlement for Public Service Electric & Gas Company in April 1999, the BPU rejected an alternative settlement offered by marketers that offered higher shopping credits.

On the other hand, if the retail generation credit is set too low, the low credit would make it artificially difficult for new entrants to compete in the market. In this case, consumers would have strong incentives to select the standard offer provider and competitors would have strong incentives to exit (or forego entry) into the market. This actually occurred in Massachusetts, where the standard offer price was set administratively based on forecasts. These prices rapidly became outdated as a result of closures of nuclear power plants and other changes in market conditions in New England. The standard offer became artificially cheap and consumers have been slow to switch. On March 1, 1998, the Massachusetts regulatory agency approved standard offer rates for each of the Massachusetts distribution companies equal to 2.8 cents per kWh. Shortly thereafter, significant changes in the availability of generation resources in the region (especially nuclear) occurred, which sharply changed market conditions. The rate for each of the companies remained at 2.8 cents/kWh for the remainder of 1998, with two exceptions: (a) Boston Edison increased its Standard Offer rate to 3.2 cents/kWh on June 1, 1998, concurrent with the completion of the divestiture of its non-nuclear generating units; and (b)

Massachusetts Electric Company increased its Standard Offer rate to 3.2 cents/kWh on September 1, 1998, concurrent with the completion of the divestiture of New England Power Company's non-nuclear generating units. As a result, the standard offer price became too low and competitors found that they could not compete against this standard offer price. More recently, settlements have led to further increases in Standard Offer rates in Massachusetts. (see:http://www.state.ma.us/dpu/restruct/competition/standardoffer.htm)

In either case, an artificially high or low retail generation credit distorts competitive pressure in the retail electricity marketplace thereby tilting the competitive playing field such that the market share of less efficient producers could be higher than would be the case if the retail generation credit was set in an economically efficient manner.

CUSTOMER SWITCHING IN NEWLY COMPETITIVE ELECTRICITY MARKETS

Q. What information have you reviewed on customer switching in newly competitive markets?

A. I have reviewed four broad categories of information. First, I have reviewed the available empirical evidence on the levels of actual switching that have occurred following the introduction of retail competition in a number of jurisdictions both in the U.S. and abroad. Second, I have reviewed, to the extent that this information is available, the level of savings (or added value) that has been available for customers in markets that have opened up; as one would expect, all things being equal, the higher the level of benefits that are available to the customer, the greater the level of switching. Third, I have reviewed research studies, such as surveys of consumers, that explore the role of price and non-price attributes in determining switch rates. Fourth, I have reviewed additional information on: (a) the potentially important role that voluntary aggregation programs could play in Ohio; (b) the potential impact of retail competition in the marketing of natural gas in Ohio on Ohio consumers' switching rates in retail electricity markets; and (c) consumer demand for value-added electricity services (such as green power).

Q **What conclusions have you drawn based on this review?**

A. I have drawn three primary conclusions as follows:

1. Industrial customers are responsive to choice. My review of the available data suggests that a significant percentage of industrial and commercial customers have switched if they could achieve some relatively small level of savings (or can gain added value) from doing so. Thus, subsidies will not

be needed to induce industrial and commercial customers to switch.

2. For residential customers, the evidence from other states and countries is somewhat less encouraging. The evidence suggests that residential customers are less prone to switch.

3. In Ohio, however, the potential for customer switching in the residential market is more robust. Ohio consumers could choose to join aggregation programs (which offer an opportunity to switch in a way that reduces the consumers' search and other transaction costs regarding switching), are already experienced with competition in natural gas markets, and could switch in order to use value-added products and services, such as green power. Given these considerations, shopping incentives are not likely to be needed in Ohio.

Given the potential benefits to consumers that retail competition could provide, there is no reason, at this time, to provide an artificial boost to new entrants via shopping incentives. Rather, the Commission should allow markets to develop naturally, with consumers switching if they see the opportunity of benefits from doing so. After all, if there is no savings to be had from switching or other benefits from switching, where entry is open and choice is available, switching would add no value whatsoever to the economy.

COMMERCIAL AND INDUSTRIAL LOAD SWITCHING

Q. Does the available evidence suggest that shopping incentives will be needed in order to induce industrial and commercial customers to shop?

A. No. The economics of electricity consumption for large volume customers, such as industrial customers and most commercial customers, create significant incentives for these customers to search out competitive alternatives. The evidence that I have reviewed from other jurisdictions suggests that shopping incentives will not be needed to artificially induce switching by CG&E's industrial and commercial customers. Substantial numbers of industrial and commercial customers will switch if they anticipate achieving at least some modest level of savings or added value in doing so.

Q. Please provide an overview of the economics of switching for industrial and commercial customers.

A. The economics of electricity consumption for large volume customers creates significant incentives for these customers to search out alternatives to utility service.

Switching is economically attractive to large commercial and industrial (C&I) customers for a number of reasons. First, on a $/kWh basis, the transaction costs of evaluating and selecting competing offers are likely to be relatively small compared to the potential benefits of doing so. The average industrial customer's load is likely to be large enough to provide savings net of transaction costs.

Second, small decreases in electricity costs can have a large impact on operating expenses for industrial and commercial users of electricity. Electricity expenditures often comprise a significant portion of C&I customer's operating costs. Thus, if the retailer is able to provide a discount of several mills relative to utility service, these small changes in the cost of electricity can have a significant impact on the company's bottom line.

Third, investments in value-added services may increase commodity savings. Retailers can provide services that are customized to meet specific client needs. Examples of these services include complex tariffs, load interruption programs that are more closely aligned to the needs of the company (vs. a one-size-fits-all program), energy efficiency or process reengineering services, and enhanced billing features (*e.g.*, the ability of a national retailer to serve customer load across numerous jurisdictions and provide a single, consolidated bill for all customer sites, or the ability to utilize the Internet to view and download hourly energy charges by site). While these services are often referred to as value-added, they are chosen by the C&I customer for their potential to deliver savings, relative to traditional service. Thus, the value-added services a retailer may offer can lower the costs of doing business by: (a) reducing transaction costs (*e.g.*, superior bill formats streamline the customer service relationship); (b) increasing the customer's understanding of the nature of its electricity usage and the costs of its consumption patterns (*e.g.*, access to demand data, detailed billing); and (c) lowering the customer's electricity costs (*e.g.*, specialized tariffs or load interruption or energy efficiency programs).

Fourth, large volume customers are attractive prospects to retailers and tend to be aggressively courted by new entrants. Even in states where savings from switching are limited for the typical electricity user, sufficient savings could potentially be available for large customers with attractive load characteristics.

Q. Please summarize the available evidence on switching by industrial customers in jurisdictions that have already introduced retail competition.

A. There is considerable empirical evidence that switching by industrial and large commercial customers tends to be sizable and rapid following the introduction of retail competition. Based on the available evidence, the trend is clear—over 20% of industrial and commercial customers (C&I) have typically switched in the first year or two after retail competition was introduced.

Newly competitive electricity markets in the U.S. and abroad offer some of the strongest evidence regarding the number of C&I customers that will leave the incumbent utility after the retail market is opened to competition. I will briefly summarize this market evidence:

- *England.* Since 1990, customers with a maximum demand over 1 MW in England and Wales have been able to take electricity from their local Public Electricity Supplier (PES) or from a competitive supplier. In the first year of competition, over 20% of the industrial customers left the PES in England and Wales. According to data supplied by the regulator for England and Wales, OFFER, at the end of the first year of competition, the percentage of sites over one MW that were served by a competitive supplier was 28%. These sites account for 39% of total load served in this class. These switch rates have tended to increase over time. Today, after nine years of retail competition, the total number of sites served by a competitive provider is 67%, accounting for 80% of all load in this class. (Office of Electricity Regulation, Annual Report, 1998, p. 31.) In

April 1994, retail competition was phased in for customers with a maximum demand over 100 kW. In 1994-1995, 25% of all customer sites in the 100 kW to 1 MW class switched to an alternative provider. This switching accounted for 30% of load. Today, 48% of all customer sites in this size class have left the PES, accounting for 61% of load.

- Victoria, Australia. Retail choice began in 1994 when 500 of the region's largest customers (hourly peak demand over 1 MW) were able to choose their supplier. A second phase-in of about 2,000 large industrial and commercial customers (annual loads exceed 750 MWh) followed in July 1996. Victoria does not keep public switching statistics for large volume customers. However, in August 1996 the Australian Chamber of Manufacturers (ACM) surveyed eligible customers (above 750 MWh per annum) to determine how many customers had switched. The study found that 35% of respondents reported selecting a new electricity supplier as of August 1996. (Australian Chamber of Manufacturers, Customer Feedback on Victoria's Competitive Electricity Market: A Report on the ACM Survey of Contestable Electricity Customers, November 1996.

- *Massachusetts* launched retail competition in March 1998, one month before the inception of the California market. In Massachusetts, competitive suppliers provided about 1.30% of distribution company retail electricity sales to industrial and commercial customers by the first quarter of 1999. (Commonwealth of Massachusetts Division of Energy Resources, DOER Report: 1998 Market Monitor, September 1999, p. *iv.*) This results from standard offer rates that were lower than the wholesale costs of electricity because of changes in market conditions. In many cases, suppliers captured these customers through aggregation groups such as the Health and Educational Facilities Authority, the Massachusetts Municipal Association, and chambers of commerce.
- *California.* The California market has been open since April 1998. As of October 31, 1999, competitive providers are serving 31.3% of industrial customers' load and 5.7 % of commercial customers' (20–500 kW) load.
- *Pennsylvania* introduced retail competition in 1999 (although some pilot programs were in place before 1999); the specifics on the timing of the introduction of retail competition vary on a utility-by-utility basis. For most utilities, up to two-thirds of their electric customers were

able to participate in retail competition beginning on January 1, 1999. Some utilities have not had a phase-in. For example, GPU Energy and Pennsylvania Power & Light agreed to provide residential customers with retail access by January 1999. In PECO Energy's service territory, all customers were given access to the retail market by January 2, 1999. As of October 1, 1999 (nine months into the market), the range of switch rates for industrial customers, based on percent of load served, varies from a high of about 73% for GPU Energy to a low of about 11.6% for Allegheny Power. For commercial customers, based on percent of load served, the range of switch rates varies from a high of about 52% for GPU Energy to a low of about 17% for Penn Power.

Q. Please discuss the role that the amount of savings plays in determining whether C&I customers switch.

A. It seems likely that the variation in the levels of switch rates seen in the markets discussed above can be explained largely by differences in the level of savings (or added value) that are available to customers; limited information is available on the level of savings that can be gained by switching. Generally speaking, all else being equal, the higher the level of savings available to the C&I customer, the larger the level of switching that would be expected. Although information is limited, this relationship appears to be generally borne out in the markets that have already introduced retail competition (*e.g.*, because of a low standard offer price, little switching has occurred in Massachusetts).

Q. What conclusions can you draw from your review of customer switch rates and savings for industrial and commercial customers?

A. There are several useful conclusions that can be drawn from research and market experience. First, C&I customers have tended to rapidly exercise their option to choose an Certified Supplier. This suggests that intervention in the retail market is not necessary to induce large volume customers to leave the utility in favor of competitive suppliers. Large volume customers seek out their opportunities shortly after the inception of retail competition.

Second, the level of switching is related to the level of savings offered in the market. This pattern is similar to that found in many other types of competitive markets. These savings stem from not only price discounts (relative to the cost of generation under traditional service), but also the opportunity to achieve additional savings through energy efficiency or load aggregation programs. As long as retailers are able to offer C&I

customers some opportunity to save, these customers are likely to switch.

Large volume customers will be pulled into the competitive marketplace by retailer offers at levels that meet or exceed the targets established by the legislature. Therefore, shopping incentives are not likely to be needed to artificially induce shopping by industrial and commercial customers.

RESIDENTIAL LOAD SWITCHING

Q. Please evaluate the prospects for switching by residential customers.

A. Experience provided to date in retail markets that have opened up, as well as research that examines the factors that motivate small volume customers, both suggest that residential customers are not as likely to switch to a new retail provider, at least in the short run. Generally speaking, switch rates are lower for residential customers than for C&I customers. In Ohio, however, factors such as the availability of aggregation and experience with retail competition in natural gas, should sufficiently increase the attractiveness of switching for residential customers.

Q. Please describe the economics of switching for residential customers.

A. The economics of electricity shopping and switching for small volume customers are not as favorable as they are for industrial and commercial customers. Search, information, and other transaction costs can be high for residential customers and many of these customers have limited opportunities to achieve substantial savings from switching. Most importantly, electricity purchases comprise a relatively low portion of residential household expenses (especially for the portion of the electric bill that is becoming competitive).

Q. For retail competition to benefit residential customers, must a significant number of these customers actually switch providers?

A. No, simply having the option to choose provides benefits to consumers. While it is important that markets be open to entry by competitors and that customers be able to choose providers for themselves, residential customers do not necessarily have to switch to benefit from competition. The combination of open entry for suppliers and choice for customers can provide the affirmative benefits of competitive markets (*e.g.*, efficient resource allocation, accurate price signals, and incentives for innovation, etc.) while also avoiding many of the negative attributes of the former regulated system. Residential customers would only switch if they perceived that they would gain additional benefits, over and above the value provided by standard offer or default service.

If policy makers focus primarily on providing openness of entry into markets and choice for consumers, markets would be used to discover consumer preferences and wants, as well as the best way of organizing the industry and the firms in it. Regulators should permit market structures some time to evolve through customers' demands and firms' responses to them, not by regulatory planning and design. Clifford Winston insightfully points out that:

> Economic deregulation does not happen overnight. It takes time for lawmakers and regulators to dismantle regulatory regimes, and then it takes more time for the deregulated industries to adjust to their new competitive environment. ... Deregulation is a long-term process from which society will continue to reap benefits as firms continue to adjust to free market competition and as more industries are more fully deregulated (Clifford Winston, "U.S. Industry Adjustment to Economic Deregulation," *Journal of Economic Perspectives*, Summer 1998, pp. 89-110).

If regulators succeed in creating an effective open access competitive environment, then those firms that are most efficient at attracting and meeting the needs of consumers will be successful. Even more importantly, consumers will be able get what they want at favorable prices.

Q. Please summarize the available evidence on switching by residential customers in jurisdictions that have already introduced competition.

A. All of the regions that were discussed above, with the exception of Australia, have introduced retail choice for residential customers (as well as for C&I customers).

In the case of England & Wales, choice has been phased in for customers under 100 kW (this class includes both residential and small commercial classes) based on individual schedules established in each of the 14 Public Electric Suppliers (PES) areas. In each region, phase-in has begun during September and December 1998. In Phase 1, 10% of all customers are permitted to choose (based on postal code). In Phase II, which followed about 13 weeks after Phase I, an additional 30% of customers were phased in. Finally, in Phase III, also occurring about 13 weeks later, the remaining eligible customers were given choice. By May 24, 1999 all PES had completed the phase-in. Therefore, since this date all of the country's customers under 100 kW could choose a competitive retailer, and in some regions full access for all customers came sooner. Data provided by the regulator in England, OFFER, indicates that as of September 1999, about

10% of the country's 26 million eligible customers under 100 kW are currently served by a retailer. This is about 2.7 million customers. Another three million customers are registered to change suppliers and are in the process of being switched. Considering those who switched and who are likely to be switched in the near future, the total rate is nearly 22%. Load data for these customers is not available.

Information provided by the Massachusetts Department of Telecommunications and Energy suggests that switch rates for residential customers are very low, which is likely due to the relatively low standard offer rates that have been in effect in the state.

In California, as of October 31, 1999, 1.9% of residential customers' load is served by competitive providers. As of June 1999, this figure stood at about 1.1%. For small commercial customers (under 20 kW), competitive providers serve 4.1% of load.

In Pennsylvania, residential switch rates vary by utility region and range from a low of 1.5% of residential customers' load for Allegheny Power and a high of 17.8% for Duquesne Light.

Q. **Is the potential for savings an important consideration for residential consumers?**

A. Yes. Like commercial and industrial customers, residential customers would tend to switch when they expect to save money by doing so. While public information is limited, the relatively low switch rates in Massachusetts likely result, in large part, because significant savings have not been available to consumers because of the low-priced standard offer service that has been available in that state.

Q. Are there additional considerations in Ohio that could affect switching rates by residential consumers?

A. Yes. I would emphasize four considerations.

1. *Aggregation.* The municipal aggregation provisions of Ohio's Electric Restructuring Bill provide a low transaction cost opportunity for residential customers to save by joining an aggregation pool. So long as a residential customer affirmatively and voluntarily chooses to enter an aggregation pool, aggregation can be a very appropriate tool to provide benefits to consumers.

2. *Consumer surveys.* In surveys, a substantial percentage of consumers have expressed a willingness to switch suppliers so long as some minimal (*i.e.*, 2%) level of savings is available from switching.

3. *Competition in natural gas.* Competition in natural gas marketing has been present in CG&E's service territory

since October 1997. This provides an opportunity for marketers to provide two products, natural gas and electricity, to residential customers. Thus, residential customers could select a competitive provider for both natural gas and electricity, which might provide them with additional savings.

4. *Green power and other value-added services.* While price is the predominant consideration for smaller customers, it is generally accepted that non-price attributes of service enter into the customer's decision making process. Some residential customers, for example, have expressed interest in renewable energy and have indicated a willingness to pay a premium (relative to utility service) to receive green power from a retailer.

Q. Please discuss the potential impact that aggregation could have on switching by residential customers in Ohio.

A. The aggregation provisions of Ohio's legislation provide a low transaction cost opportunity for residential customers to save by joining an aggregation pool. As a result of these provisions, it is much more likely that the 20% switching target can be met without resorting to subsidies to induce residential customers to switch.

Voluntary load aggregation refers to the uncompelled organization of consumers, either on their own, or as the result of some seller's initiative, into groups that purchase electricity at competitive prices. So long as a residential customer affirmatively and voluntarily chooses to enter an aggregation pool, aggregation can be a very appropriate tool to provide benefits to consumers. Aggregation provides a significant opportunity to increase residential switching rates in an efficient way. Load aggregation could provide a vehicle that would allow consumers (especially residential and small business customers) to be served at lower prices (*e.g.*, closer to the wholesale price of electricity). By grouping together, the buying power of the group could increase; in particular, the economies of scale and scope that are provided by aggregating could be supplemented if there are opportunities to achieve additional efficiencies by creating more attractive load characteristics. Aggregation via affinity groups can be viewed as merely a marketing ploy by retailers and not necessarily the most efficient way to provide retail electricity service to consumers. Over time, however, the competitive market will determine what works and what does not.

Load aggregation could occur in a number of ways. For example, municipalities could aggregate the load of residents that voluntarily opt in. (The municipality would need to be properly authorized to perform these services for the municipality's citizens and businesses.) This could be particularly important in Ohio given the features of the Ohio legislation that facilitate municipal aggregation. Municipalities will be able to aggregate their load in ways that present an attractive market for wholesale suppliers and markets. If only two or three municipalities in CG&E's service territory develop aggregation programs, a sufficient number of residential customers could switch, thereby meeting the switching target without the need for subsidies via shopping incentives.

In addition, trade organizations could aggregate load for their members. Electricity users could organize into buyer cooperatives, or aggregation programs could be developed for low-income customers. In these many possible ways that could evolve as markets develop, residential consumers and small businesses who might not otherwise be attractive to energy marketers could band together (similar to group insurance or affinity-group credit cards) to economize on their electricity costs.

Q. Please discuss the information provided by surveys of CG&E's consumers.

A. Switch rate differences can be explained primarily by differences in the level of savings and other benefits that are available to customers. The impact that these factors have on switch rates has been investigated.

In a recent survey, for example, about 38% of CG&E's consumers expressed a willingness to switch suppliers so long as some minimal (*i.e.*, 2%) level of savings is available from switching. This was an increase from about 35% in 1998. The likelihood of switching increases if a 5% savings is assumed to be available. The testimony of CG&E witness Richard Stevie provides a more detailed discussion of this survey.

The lessons learned from forecasting efforts are that smaller-volume customers tend to switch in somewhat smaller numbers, relative to large industrial and commercial customers. CG&E's residential customers have clearly indicated a substantial willingness to switch to obtain relatively small savings.

Q. **Please discuss the potential impact on switching provided by competition in natural gas.**

A. Competition in natural gas marketing has been present in CG&E's service territory since October 1997. While a number of states have begun, or are beginning, customer choice programs, Ohio is one of the first states to have competition in both its retail electricity and natural gas markets. (New York is another state that has retail competition in both gas and electricity. New York has had natural gas competition since March 1996 and retail electric competition began in mid-1998 for most investor-owned electric utilities.) The presence of retail competition in both natural gas and electricity markets in Ohio provides a significant opportunity for marketers to provide two products, natural gas and electricity, to residential customers. As a result, residential customers would be more likely to switch electricity providers.

Marketers that offer both gas and electricity could conserve on the marketing costs associated with attracting new customers, thereby increasing the potential for benefits that can be passed on to consumers. A retailer's ability to earn economic profits will depend upon whether the prices that it is able to charge its customers are sufficiently in excess of the sum of the wholesale cost of electricity and the other costs (*e.g.*, customer acquisition costs, back office costs, etc.) which it incurs to provide retail services. Customer acquisition costs will be a particular challenge. To the extent that margins are tight, and customers that have switched have a tendency to switch again, marketers may find it difficult to recover the costs of seeking and attracting additional customers. The margins that are available to retailers in markets where retail competition has been introduced are reported to be tight. The economies of scale and scope and reduced transaction costs that are provided by one-stop shopping of gas, electric and other services could potentially provide efficiencies that allow the retailer to efficiently provide service to consumers who, at first glance, do not appear to be particularly attractive. After all, retail markets meet a wide variety of consumer demands.

For consumers, the search, information, and other transaction costs that residential consumers bear when selecting a competitive provider can be reduced, which would reduce an economic barrier that residential customers face when considering switching providers. For example, residential customers could select a competitive provider for both natural gas and electricity, which might provide them with additional savings. Retailers that provide both gas and electric retail services may be better able to use technology to provide information to their customers efficiently, which would serve to reduce the transaction costs borne by customers in searching for a competitive provider of retail electricity services. By providing both gas and electric service, the retailer might be able to develop a relationship that the customer values, because the retailer has a better understanding of the customer's needs relative to alternative providers.

Q. Please discuss the potential impact of green power and other value-added services on residential switching rates.

A. Non-price considerations can be an important factor in providing residential customers with incentives to switch. While price is likely to be the predominant driver for residential customers (and for C&I customers as well), non-price attributes of service enter into the customer's decision making process. Some residential customers, for example, have expressed interest in renewable energy and have indicated a willingness to pay a premium (relative to utility service) to receive green power from a retailer.

A study, which was recently released by the National Renewable Energy Laboratory, found that 70% of residential customers would be willing to pay at least $5 more for renewable energy, 38% would be willing to pay at least $10 per month more, and about 21% would be willing to pay $15 per month more. (Barbara C. Farhar, "Willingness to Pay for Electricity from Renewable Resources: A Review of Utility Market Research," National Renewable Energy Laboratory (NREL/TP.550.26148), July 1999, p. *v*.) All else being equal, the availability of green power in a market would tend to increase residential switch rates because some portion, perhaps significant, of the residential market is interested in these offers.

Q. Why is it important to get some actual experience before providing a switching subsidy?

A. Actual experience will be needed before the Commission will have the information it will need to determine whether a shopping incentive is needed to meet the switching target. Then, if needed, a decision on where and how that subsidy could best be provided, and the terms on which it would be needed, would be necessary.

It would clearly be premature to set shopping incentives now, before sellers have even begun to approach potential customers with their offers. First, prices must be unbundled and set at economically appropriate levels. Then, trends in switching by industrial, commercial, and residential customers can be tracked for one or two years. If sufficient savings or other benefits are not available to pull (or induce) people to switch or if there are impediments to switching that cannot be overcome in ways that are economically more efficient, then additional targeted subsidies could be developed. (I would, however, emphasize yet again that artificially inducing such switching would not benefit consumers if inefficient competitors' market shares increase at the expense of more efficient competitors). It is very important, however, that the Commission first allow market forces to operate as naturally as possible at the retail level so that any additional subsidy to encourage switching, such as a shopping incentive, can be targeted and designed to be as least-wasteful and distorting as possible.

Q. Do you have any suggested steps that the Commission could take to avoid the need for inefficient shopping incentives?

A. Yes. The Commission should consider measures to reduce the search, information, and other transaction costs of smaller users of electricity, while taking care to avoid unduly disrupting the market discovery process, through well-targeted consumer education programs. Importantly, the Commission could provide training and other support in order to encourage efforts that encourage voluntary aggregation programs for smaller energy consumers. CG&E's Consumer Education Plan already anticipates training alternative suppliers on new customer choice procedures. Training potential aggregators as part of this program could be a cost-effective way to increase voluntary aggregation without subsidizing switching. These efforts may be beneficial in introducing retail competition and are likely to be more cost effective than shopping incentives would be.

Q. If shopping incentives are eventually used, should they be implemented in the least wasteful and distorting manner possible?

A. Yes. To the extent that a switching subsidy is needed to meet the 20% requirement for residential customers, the Commission could:

1. Forego the 5% decrease in the unbundled generation component in order to avoid unduly discouraging entry by competitive suppliers. (R. C. 4928.40(C))
2. Make any shopping incentive subsidy as explicit as possible.
3. Target subsidies to only those customer classes that need a subsidy (*e.g.*, residential customers) in order to meet the legislative switching target.
4. Carefully design the subsidies to reduce the risk that inefficient subsidies will continue in effect beyond the time necessary to achieve the 20% target.

Q. If actual experience suggests that customers are slow to switch, what should the Commission do first?

A. If, after a period of actual experience, the Commission concludes that the rate of switching is too low, the Commission should first consider foregoing the 5% decrease in the unbundled generation component because this rate decrease clearly tends to discourage entry by competitive suppliers and creates inertia because customers have already obtained savings. (R. C. 4928.40C) Further, the rate decrease has no apparent economic basis and the legislature expressly left open the option of eliminating this rate decrease if it discouraged switching by customers. In order to efficiently introduce retail competition, the Commission can terminate this rate reduction if it is unduly discouraging market entry, which would lead to the need for additional switching incentives.

Given the obvious benefits of a 5% rate decrease to consumers, if this rate decrease is terminated or limited, the Commission must ensure that consumers receive an equivalent benefit. Most importantly, this would occur automatically under Ohio law because the transition cost recovery will be automatically shortened if the 5% rate cut is eliminated. This approach would provide a significant benefit to consumers—while avoiding distortions in the development of competition that could harm consumers in Ohio.

To the extent that the standard offer is priced at an artificially low level, much larger shopping incentives would be needed to encourage customers to switch. A better solution would be to allow the standard offer price to be at a level that reflects underlying market conditions but to use the revenues that result from this higher price to shorten the stranded transition cost recovery period, which would provide benefits to consumers without distorting incentives to switch.

Q. What should the Commission do if, after a period of actual experience, sufficient numbers of customers have not voluntarily chosen to switch?

A. Depending on the actual marketing and switching experience, additional information programs or even targeted incentives to induce additional switching (*e.g.*, a 2% shopping incentive for residential customers) might be considered in order to meet the legislature's switching target—assuming that the legislature does not change or eliminate this target.

After a suitable period of practical experience, regulators could develop targeted subsidy payments, if necessary, in order to induce additional switching by residential customers. It will take some time for some customers, especially smaller-volume residential and commercial customers, to evaluate the benefits of competitive service and, where appropriate, make the commitment to switch providers. On the supply side of the market, it will take product innovation and entrepreneurial investment to develop a marketing strategy that offers smaller volume customers benefits that outweigh the transaction costs of switching.

To the extent that subsidies are clearly shown to be needed in order to induce 20% of a customer class to switch, even the best implementation of the customer switching target would be economically wasteful. The Commission should nevertheless at least strive to make the best of a conflicted situation.

Q. Please explain why any shopping incentive should be as explicit as possible.

A. To the extent that shopping incentives are needed to induce switching at rates sufficient to meet the legislature's 20% requirement, it is very important that these charges be as explicit as possible. The switching subsidy should not be rolled into the price of generation (because it does not reflect the true price of generation) but should instead appear as a separate credit or line item on the customer's bill.

In any competitive market, price transparency is fundamental to achieving economic efficiency. The price provides consumers with a measure of the product's scarcity. By lumping a shopping incentive into the standard cost of service, the price signal is muddied. A subsidy should be explicit and consumers should be aware that they are being provided with an incentive to switch.

Q. Please explain why subsidies should be targeted to only those customer classes that need a subsidy.

A. Targeting subsidies to only those customer classes that need a subsidy (*e.g.*, residential customers) in order to meet the legislative switching target is likely to be less wasteful of society's resources. Where the legislature's 20% switching target is achieved in the market, no additional regulatory action is necessary or warranted.

Q. **Why should subsidies be designed to not continue in effect beyond the time necessary to achieve the 20% target?**

A. Switching subsidies should be designed to reduce the risk that inefficient subsidies will continue into effect beyond the time necessary to achieve the 20% target. To leave the subsidy in effect indefinitely would go beyond the goals of giving purportedly infant firms a boost and virtually guarantees the survival of inefficient competitors. This would raise, not lower, the overall cost of electricity. Thus, any switching subsidy should end once the 20% target has been reached.

Q. **Please comment on CG&E's sliding-scale shopping incentive scheme.**

A. CG&E has proposed the following scheme if sufficient numbers of residential customers do not affirmatively choose to shop to meet the 20% shopping incentive target. After one and one-half years of practical experience has been gained, and the level of switching is found to be below 10%, a 2% shopping incentive (as a percentage of the unbundled generation rate) would become available in July 2002, in order to provide an additional incentive for customers to switch to a competitive provider. At the same time, the 5% rate decrease would end; instead, customers would benefit from a more-rapid recovery of transition costs, which could allow an earlier end to the market development period for the recovery of transition (stranded) costs. Finally, if the Commission determines that some additional incentive is desirable if switching has not reached the 15% level by January 2003, some additional shopping incentive (*e.g.*, 5% of the unbundled generation rate) could become available at that time. A 5% shopping incentive would provide customers' with value, as a percentage of their total bill, of about 2%. As discussed earlier, CG&E's survey of customers indicates that this amount of savings would be sufficient, over time, to induce over 20% of customers to switch. Such steps may be viewed as necessary in the context of the switching target (which is not a mandate) that has been placed on the Commission.

Nevertheless, although these steps to encourage switching are laid out quite cautiously, I continue to have severe concerns about the use of shopping incentives to provide a subsidy to artificially induce switching by customers. Attempts to jump-start or manage the formation of specific retail markets, which is supposedly justified in order to move more quickly to competitive markets, is in fundamental conflict with reliance on open entry and consumer choice to develop a competitive electricity market. In particular, shopping incentives would tend to subvert the process of allowing commercial success for competitors to flow from offering the lowest price service and or delivering the highest value.

Having said this, however, I can, as a former regulator, appreciate that regulators must strive to meet the legislature's switching target. CG&E's proposal would provide a clear path to follow if a sufficient level of customer switching does not occur through voluntary and affirmative actions by consumers. Importantly, any artificial shopping that is provided by regulators should be targeted to only those customer classes that need a subsidy and should sunset once the switching target has been achieved.

MARKET POWER ISSUES ARE ADEQUATELY ADDRESSED IN CG&E'S TRANSITION PLAN

Q. Based on your review of CG&E's Transition Plan, what conclusions have you drawn with respect to market power issues?

A. My basic conclusion is that CG&E has developed, in their Transition Plan, an approach that effectively addresses the legitimate market power issues that arise when restructuring the electric utility industry. CG&E's Transition Plan—viewed as a comprehensive whole—more than adequately addresses the potential vertical market power issues that arise in restructuring the electric utility industry (unfortunately, however, this is accomplished, in part, by foregoing the potential realization of economies of scale and scope). Further, CG&E will not be able to exercise horizontal market power in the newly competitive retail electricity market.

Q. What is market power?

A. Most economists define market power as the ability to profitably raise prices significantly above competitive levels for a sustained period of time and/or to exclude potential competitors from the market.

Q. Is market power a legitimate concern in restructuring the electric utility industry?

A. Yes. Regulators in this industry are properly concerned that utilities wishing to operate in newly competitive markets not be able to exercise market power, regardless of how it arises. For efficient competition policies to prevail, it is critical to understand precisely what market power is, and just as importantly, what it is not.

The fundamental cause for concern about market power is the effects that it can have on consumers—not the effects on competitors. Regardless of precisely how the market power is gained, the focus of concern should be on the consumer. If a firm is unable to raise prices and restrict output, there is no market power problem even if the firm has lower costs relative to some of its competitors, has profitable operations, or has a significant market share. Importantly, the degree of success or lack of success of the firm's competitors plays no role in the definition of market power. Rather, the most important consideration is that the market be open to entry by competitors, so that consumers have choices available to them.

Q. Are there different types or classifications of market power?

A. Yes. There are two classifications of market power: vertical and horizontal.

Q. What is vertical market power?

A. Vertical market power refers to the possibility that a firm may be able to use its market power at one stage of the production process, such as transmission or distribution, to influence price and output at another stage, such as generation, retail sales, or new, less closely related markets. This assumes, of course, that entry or the threat of entry by new competitors will not be able to sufficiently police price increasing behavior in those markets. The principal vertical market power concern in the industry to this point has been that integrated transmission owners could use their control of bottleneck transmission facilities to favor sales of their own generation over sales by their competitors. At the federal level this concern has been addressed by FERC Order

Nos. 888 and 889, as well as by the continuing formation of Independent Transmission System Operators (ISOs) and other transmission institutions, such as private, profit-oriented Independent Transmission Companies (Transcos).

As retail competition unfolds, a similar concern arises over the use of the distribution system. The practical reality is that the transmission and distribution wires portion of the business (a bottleneck for all competitors who wish to enter the market) will likely remain a natural monopoly for some period of time, and this poses special problems. Emerging vertical market power concerns for retail access regimes primarily involve whether entities that own both wires and retailing affiliates can use their control of the wires to favor their own retail affiliates.

Q. What is horizontal market power?

A. Horizontal market power concerns may arise in an unregulated market when a few firms hold a large fraction of the market at some stage of production in an industry and where the threat of entry by new firms is insufficient to limit the incumbents' ability to restrict output and raise price at that stage. In the newly competitive generation commodity and retail sale markets that are being opened to entry by competitors, it is important to recognize that market share is not the same as market power. So long as entry into the market is open and consumers have the ability to choose for themselves, utility providers of default or standard offer services will not be able to exercise horizontal market power in these markets. Further competition by utility affiliates in the newly competitive generation and retail markets is more likely to improve the robustness of competition rather than be somehow anti-competitive.

VERTICAL MARKET POWER

Q. Please explain how the Ohio legislation addresses vertical market power issues.

A. The Electric Restructuring Bill fundamentally transforms the role of distribution utilities in the state in order to accommodate retail competition. Distribution utilities will provide unbundled, open, nondiscriminatory, competitively neutral and comparable service to their distribution customers. Retail electricity sale markets will be opened to entry.

Q. Please summarize the components of CG&E's plan with an emphasis on how the components relate to legitimate vertical market power concerns.

A. CG&E's Transition Plan addresses vertical market power issues primarily through the requirements of its Corporate Separation Plan. Instead of a vertically integrated utility that provides generation, transmission, distribution, and aggregation services on a bundled basis, CG&E's Corporate Separation Plan requires that: (a) CG&E become a T&D utility and provide standard offer and default service to customers that do not affirmatively select a competitive provider; (b) generation be transferred to a separate subsidiary, with a power purchase agreement that provides CG&E with sufficient power to meet its obligation to provide standard offer and default service; (c) the Midwest ISO will control CG&E's transmission assets; (d) CG&E will maintain its accounting for affiliate transactions in compliance with PUHCA; and (e) the Commission has adopted strict affiliate code of conduct rules in order to prevent behaviors that could be considered to be anti-competitive. Retail energy marketing activities, if CG&E eventually decides to enter this business, would be provided in a separate subsidiary.

In addition, the Independent Transmission Plan, the Rate Unbundling Plan, and the Operational Support Plan play important supporting roles in providing an assurance that generation commodity and retail markets are open to entry. I will not address the other components of the plan, which have less relevance to vertical market power issues.

THE CORPORATE SEPARATION PLAN

Q. What is the purpose of this section of your testimony?

A. In order to provide a broad perspective on the subject, I discuss the legitimate need for some form of corporate separation to address vertical market power issues, including the role of codes of conduct in governing utilities' interactions with their electricity generation and marketing affiliates.

Q. **How does the Corporate Separation Plan address vertical market power?**

A. The corporate separation plan presents a very major break with the past structure of the utility industry. CG&E's Corporate Separation Plan sets forth a market structure that fundamentally transforms its operations. Rather than provide bundled generation, transmission, distribution, and retail sale services for all of its customers, the vertically integrated investor-owned utilities are fundamentally restructured. Generation is transferred to a utility affiliate. An independent transmission entity operates the transmission system on behalf of all suppliers in an open, nondiscriminatory, and comparable manner. The distribution utility, once retail competition begins, provides distribution services on an open, nondiscriminatory, and comparable basis. It also provides a standard offer or default electricity service for those customers who do not select a supplier explicitly.

As part of the Corporate Separation Plan, codes of conduct that govern the relationship between the utility and its unregulated energy marketing affiliates (if any) guard against behaviors that would damage efficiency by allowing the utility or its affiliate to exercise vertical market power and that would therefore harm consumers. Such codes, however, must not be so restrictive as to destroy the efficiencies that can be captured through shared services or to handicap an affiliate and thereby decrease overall competition. The objectives of codes of conduct should be focused and limited. When designing codes of conduct, regulators should focus on two main objectives. First, utilities must not subsidize affiliates. Some rules are necessary to ensure that ratepayers are not subsidizing competitive ventures and that ratepayers are insulated from risks associated with affiliates and competitive ventures. Second, utilities must not give affiliates preferential treatment. If utility marketing affiliates are active in the utility's service territory, regulators will need to ensure that the utility does not provide preferential treatment to customers of the utility affiliate. Under appropriately designed codes of conduct that address legitimate vertical market power concerns, consumers can benefit from the economies of scope and scale that can result from the establishment of utility affiliates. On the other hand, rules that hamper the ability of utility affiliates to compete will destroy the force of their competitive efforts, ultimately harming consumers.

Q. What are the primary considerations in evaluating a Corporate Separation Plan?

A. A Corporate Separation Plan should be consistent with the following objectives:

- *Address market power while preserving efficiency.* While prevention of the exploitation of vertical market power is necessary, codes of conduct should not be made so stringent that they undermine the reason for their existence. That is, the reason for implementing behavioral regulation instead of mandating divestiture (or other severe structural approaches) is that utility companies can have a beneficial impact on the competitiveness of a market through their affiliated companies. Consumers can benefit from the economies of scope and scale that can result from the establishment of utility affiliates. Rules that hamper the ability of utility affiliates to compete will destroy the force of their competitive efforts, ultimately harming consumers.
- *Prevent subsidization.* Utilities must not subsidize affiliates. Some rules are necessary to ensure that ratepayers are not subsidizing competitive ventures and that ratepayers are not subject to investment risk associated with affiliates and competitive ventures.

- *Prevent preferential treatment.* Utilities must not give affiliates preferential treatment. If utility marketing affiliates are active in the utility's service territory, regulators will need to ensure that the utility does not provide preferential treatment to customers of the affiliate. For example, the utility must not be allowed to provide superior service to these customers.
- *Enhance consumer welfare.* The main public policy reason for restructuring the natural gas and electricity industries and allowing the entry of competitive providers is to enhance consumers' welfare by promoting competition in those markets that are no longer considered to be natural monopolies (*e.g.*, the market for the electricity commodity and the retail sale of that commodity). Thus, the primary criterion for evaluating restructuring policies should be the impact that these policies have on consumers.

Q. Please discuss the Commission's affiliate code of conduct rules.

A. The Commission has adopted a Code of Conduct that includes 10 provisions. (Cinergy currently has no plans to compete in retail electricity markets but would compete in wholesale markets through an affiliate.) The Commission's code of conduct rules address the important considerations that I identified above—indeed some of these requirements go beyond what I believe to be necessary. The Commission's code of conduct requirements provide strong protections against preferential treatment by the utility of its affiliates. Many of the principles embodied in the code are designed expressly to prevent even a perception that the utility could favor its affiliates or that it could gain an advantage because of affiliation with the utility. The Commission's code of conduct addresses the following issues:

1. *Comparability.* Four provisions (Provisions (b), (c), (g), and (i)) are designed to ensure that the utility's affiliate is treated in a comparable manner to nonaffiliated companies.
2. *Confidentiality of customer information.* Provision (a) requires customer authorization of disclosure of customer information.
3. *Confidentiality of supplier information.* Provision (d) requires supplier authorization of disclosure of supplier information.
4. *Prohibition against tying.* Provision (e) addresses this issue.
5. *Prohibition against joint marketing.* Provision (f) addresses this issue.
6. *Disclosure.* Provision (h) provides a California-style disclosure that the utility affiliate is not the same company as the utility.

7. *Ensure public safety.* Provision (j) provides that the utility can take necessary actions to ensure public safety and system reliability.

These codes are more than adequate to provide the competitive protections that are required to prevent anti-competitive behavior by utilities and their affiliates.

Q. Please discuss the structural safeguards provided in the Commission's rules with respect to corporate separation.

A. The Commission's rules include severe structural safeguards, including: (a) strict prohibitions on the utility providing credit support to a nonutility affiliate; (b) required use of a cost allocation manual that is based on fully-allocated cost concepts; (c) separate accounting requirements; and (d) strict limitations on a utility' ability to share employees with an affiliate. These rules go well beyond what is necessary to address vertical market power and would result in actual or virtual divestiture of utility affiliates. The rules would thus subvert the Commission's traditional policy of allowing consumers to benefit from the economies of scale and scope that can derive from affiliate relationships. Put more colloquially, it throws the baby out with the bath water.

Q. Please evaluate CG&E's Corporate Separation Plan as a whole. First, does the Corporate Separation Plan address market power while preserving efficiency?

A. No. While the Corporate Separation Plan more than sufficiently addresses the legitimate market power concerns that arise with electric restructuring, such as comparable treatment of competitors and bans on inappropriate tying arrangements, it does so at the expense of achieving economies of scale and scope that help to preserve efficiency.

From an economist's point of view, market power is the ability to raise prices or exclude competitors. Regulation of the essential transmission and distribution systems is aimed directly at the rates to be charged and at making sure potential competitors can enter the market.

It is not necessary to engage in policies that handicap the incumbent utility or provide artificial benefits to new entrants. In a market economy, every firm seeks to use whatever unique advantages and resources it may have in providing services to customers. In fact, competitors advertise and promote these unique advantages and customers make decisions based upon the perceived value of these unique advantages and resources. The decision to rely on competitive markets is based on the notion that whoever can produce most efficiently, whoever brings the most value to consumers, should and will prevail. An economic advantage in satisfying the needs of consumers possessed by one competitor, but not by others, is not anti-competitive. It simply reflects the different skills and endowments that each and every firm brings to the market that may allow it to charge lower prices or offer better service to its customers than its competitors can. There is nothing anti-competitive about having an ability to bring lower prices or better services to customers. On the contrary, it is what competitive markets are all about.

The concern that potential entrants will be scared off if restructuring rules do not give them preferential treatment is either disingenuous or is based on unfamiliarity with the identity of the entities that are likely to enter these markets. It is simply not true that potential entrants to Ohio's electric retail markets are small, unsophisticated companies in need of strong governmental support and protection. There may indeed be some such start up entrants in newly opened electricity markets. However, among the likeliest candidates for entry are the large integrated energy companies that have come to dominate these markets over the past few years. It is simply not necessary to hand competitors—such as Enron, Statoil, Dynegy, UtiliCorp and others—market share, provide them with artificial advantages, or handicap the incumbent utility or its affiliates.

Q. Do you have any concerns about the Commission's restrictions on sharing of employees between the utility and its affiliate?

A. Yes. Bans or limitations on the sharing of employees between the utility and its retailer affiliate should be carefully considered, narrowly drawn, and based on legitimate concerns for consumer welfare. There may well be some types of employees that should not be shared between the regulated utility and a marketing affiliate. For example, utility employees who possess non-public, market sensitive information of the sort deemed valuable by the affiliate and its rivals should not be able to use this information to afford an advantage to the affiliate in the competitive market. Aside from these kinds of considerations, however, the transfer of employees should be treated no differently than other resource sharing issues; sharing means economies of scope.

Q. Will the Corporate Separation Plan prevent cross-subsidization?

A. Yes. The Corporate Separation Plan can ensure that customers of the regulated utility do not subsidize the utility's competitive affiliates. A careful definition of cross-subsidization that focuses primarily on efficiency and competitive considerations says that a set of prices charged by a multiproduct monopolist is free of cross subsidies if the revenues for each of its services is above the *incremental cost* of providing the service and below the *stand-alone cost* of providing the service. (Gerald R. Faulhaber, *"Cross-subsidization: Pricing in Public Enterprises," 65 American Economic Review,* pp. 966-977. See also Bridger M. Mitchell and Ingo Vogelsang, *Telecommunications Pricing: Theory and Practice* (Cambridge: Cambridge University Press, 1991), p. 119.) Thus, incremental cost and stand-alone cost provide a zone of reasonableness within which economists would consider a set of prices to be subsidy-free.

The CG&E Corporate Separation Plan's requirement that utility affiliates are structurally separated from the utility provides a workable and clear boundary between utility and non-utility activities that insulates the utility from the activities of its affiliate. (Unfortunately, however, the Commission rules are written so strictly that potential efficiencies from economies of scale and scope will likely be sacrificed.) Further, as a holding company under PUHCA, Cinergy must comply with PUHCA's accounting requirements in accounting for affiliate transactions; these requirements provide a strong assurance that utility customers will not subsidize non-utility ventures. Indeed, the SEC's use of fully-allocated cost methods goes well beyond the requirements of economic efficiency—but the use of fully-allocated cost in place of incremental cost can be viewed as building in a margin of protection that provides even more assurance that consumers are not cross-subsidizing the firm's competitive ventures. Third, the proposed codes of conduct would provide further protection against cross-subsidization.

Q. Will the Corporate Separation Plan prevent the utility affiliate from receiving preferential treatment?

A. Yes. In this regard, the Commission's affiliate codes of conduct would play a very important role in preventing behaviors that would advantage the utility affiliate over other nonaffiliated competitors. Many of the provisions of CG&E's code of conduct are aimed at addressing possible situations where a utility affiliate could be treated in a preferential manner. These provisions appear to me to be more than sufficient to level the playing field to ensure that all competitors in the retail markets are treated in a comparable manner.

Q. Please discuss the code of conduct's California-style disclosure requirements.

A. CG&E's Code of Conduct requires that utilities and their affiliated certified suppliers not communicate to their customers the idea that any advantage might accrue in the use of the electric utilities noncompetitive retail electric service as a result of dealing with its affiliated certified supplier. This is the disclosure requirement that is used in California and it is not unreasonable.

This approach allows utility affiliates to retain the ability to use the parent's name and logo. Marketers sometimes argue that the affiliate's use of such a corporate name or logo might somehow deceive customers into confusing the affiliate with the related utility or parent. However, customers will not be deceived by such use. The affiliate's roots in the regulated company and other corporate affiliates are a major source of any legitimate competitive advantage the affiliate may possess. The name could convey a creditable history of service in the gas or electric industry. Many of the competitors in this industry share similar histories. The corporate name could also convey a sense of localism, which may be important to some customers.

Allowing affiliates to use the same or similar names and logos can be beneficial to consumers, so long as a clear distinction between the regulated company and its affiliates is stated. Restrictions on such use actually reduce consumer welfare. Ironically, consumers lose information on who they are dealing with at a time when many regulators and state legislatures are funding consumer education programs and generally searching for ways to help consumers adjust to the new gas and electricity markets. In short, customers' search costs are needlessly raised, and so are the odds that consumers will make poorly informed choices.

Other effects may ensue as well. Clear brand identification provides accountability and, therefore, an incentive for firms to maintain quality levels and provide better service to customers. Firms will vary in their performance and reputation. In some markets, the incumbent utility's good reputation will help its competitive position and act as a spur to other firms to increase their quality or introduce some attractive new aspect of service, including quite possibly a lower price. The existence of a successful and well-regarded incumbent may be seen as a barrier to entry by some competitors, but it is a common phenomenon in many markets. Eliminating the apparent connection with the incumbent will give a windfall to new entrants but it will do nothing for customers.

Not surprisingly, marketers have been the most strident advocates of policies that would disable incumbents. For example, Enron frequently advocates proscriptions on marketing tactics or use of the utility name, yet somehow never mentions that it has chosen to forego this bit of policy advice for its own operations. Enron Interstate Pipelines, Enron Capital and Trade Resources, and Enron Power Marketing are all part of the Enron holding company family. (Enron's interstate natural gas pipeline operations are regulated by the Federal Energy Regulatory Commission.) Similarly, Shell Energy Services Company, L.L.C. is a member of the Royal Dutch Shell group, well known for gas and oil exploration, production and sales.

Once the market becomes competitive, affiliates will begin to develop their own corporate identity and reputation, based on the quality of their service. For example, companies like Federal Express (FedEx) and United Parcel Service (UPS) may have chosen names that resonated with their customers and conveyed a sense of security and reliability that used to be associated with the U.S. Postal Service. However, it seems unlikely that FedEx or UPS would have succeeded had they provided poor service or charged too much in the market. Consumers will not be fooled and will be able to make intelligent choices.

Q. Is CG&E's Corporate Separation Plan sufficient to prevent exercise of market power or preferential treatment of competitors?

A. Yes. CG&E's proposed corporate separation plan should generally prevent the exercise of vertical market power. The Commission's rules certainly protect the ability of new entrants to operate in the marketplace, albeit through the use of what are, in my opinion, stricter-than-necessary corporate separation requirements. It is more difficult to say, given that economies of scale and scope will likely be sacrificed, that consumers necessarily benefit as much as they might given the Commission's strict corporate separation rules. When addressing market power issues, the focus should be on ensuring that consumers are not harmed because firms are able to exercise market power (e.g., by restricting output or raising prices). But, as structural restrictions are adopted, there is a tradeoff between controlling market power and realizing economies of operation. Policies should be judged on whether or not they lead to net benefits to consumers through competition (lower prices, better quality, service innovation, etc.), and not whether one or another competitor benefits from their adoption.

It is all too easy to lose sight of consumers in the policy making process. There is a point at which policies can become pro-competitor rather than pro-consumer. The assumption that what is good for competitors (*i.e.*, new entrants to newly competitive markets) is good for consumers is a common error, but it is a bad principle on which to make policy. Not surprisingly, companies that wish to enter markets that are being opened to competition often advance policy proposals that appear designed primarily to handicap affiliates of the incumbent utilities and to benefit new entrants. These marketers often seem to equate policies that benefit marketers with policies that benefit consumers. This is unfounded. The Commission must be careful not to allow the corporate separation plan issues become a vehicle for policies that favor the special interests of marketing companies at the expense of utility companies or utility company affiliates and, more importantly, of consumers.

Codes of conduct have been implemented in many of the states that are restructuring their electricity industries. Many observers—myself included—believe that the rules established in some states are excessively restrictive and may well hinder rather than facilitate the development of consumer benefits. It seems quite possible that electricity customers—*who should be the primary beneficiaries of restructuring*—will not do as well in these new markets as they might have, had the rules been more moderate. This is because the rules that these states have put into effect impose substantial handicaps on the marketing affiliates of electric utility companies. In some cases, this may make it nearly impossible for these companies to compete aggressively and very difficult for them to use available scale and scope economies to provide low-cost, high quality retail electric service to consumers. This is an ironic outcome, since forcing the traditional utilities to compete has been one of the hallmarks of turning to greater reliance on market forces.

CG&E's proposed Corporate Separation Plan provides safeguards that are more than sufficient to ensure that the utility does not gain inappropriate competitive advantages as a result of its affiliation with the utility—while allowing the utility affiliate to add an additional choice for consumers by competing to serve consumers in competitive markets.

OTHER COMPONENTS OF CG&E'S TRANSITION PLAN THAT ADDRESS VERTICAL MARKET POWER ISSUES

Independent Transmission Plan

Q. Please describe the basic standards that an Independent Transmission Plan should meet.

A. Market power considerations play an important role in the operation and regulation of transmission systems. As a monopoly, transmission is regulated to prevent the exercise of horizontal market power at the transmission level. To address vertical market power issues between generation and transmission, regulators have taken significant steps to provide an assurance that control of transmission does not become a source of unfair competitive advantage by a generation owner. To address legitimate market power issues, I believe that it is particularly important that an independent transmission plan:

- *Accommodate efficient competition in generation commodity and retail sale markets.* An ISO with a high degree of independence and the authority to operate the transmission grid as a unified network would help to ensure that the transmission network operates in a way that serves the users of the network, without unduly favoring the interests of any particular user.

- *Provide open, nondiscriminatory, and comparable service.* If competition in the generation and marketing of electricity is to thrive, there must be open and nondiscriminatory access to the transmission wires. All users of the transmission system must be treated in a comparable manner.

Regional transmission operators, whether they are organized and operated as ISOs or Transcos (private, profit-oriented companies), will play a critical role in ensuring open access to transmission.

Q. Please summarize the Independent Transmission Plan's role in addressing vertical market power issues.

A. CG&E's Independent Transmission Plan plays an important role in providing an assurance that a transmission owner does not use its control of transmission to restrict or tilt competition in generation markets. If competition in the generation and marketing of electricity is to thrive, there must be open and nondiscriminatory access to the transmission wires. Otherwise, transmission owners would be able to exercise vertical market power such that entry into transmission markets might be constrained, thereby allowing the transmission owner to collect a monopoly rent.

Q. What are the major features of CG&E's Independent Transmission Plan?

A. CG&E has joined the Midwest ISO. The Midwest ISO has received FERC approval, intends to begin operation in June 2001, would operate its transmission network on a functionally separated basis, is independently governed, and would operate a very large, regional transmission system.

Q. Please evaluate CG&E's Independent Transmission Plan as a whole. First, will the plan accommodate efficient competition in generation commodity and retail sale markets?

A. Yes, I believe it will. The Federal Energy Regulatory Commission's (FERC's) efforts, largely in response to the Energy Policy Act of 1992, to increase competition in generation markets on a wholesale level has paved the way for the states' introduction of retail competition by requiring open, nondiscriminatory access to transmission (in FERC Order No. 888) and by addressing issues surrounding Regional Transmission Operators (RTO)—whether they are ISOs or Transcos. CG&E's independent transmission plan is a reasonable way to continue to move toward restructuring transmission to enhance competition in wholesale generation and retail sale markets.

Independence and *regionalization* are important considerations in determining whether an ISO is consistent with efficient competition. An ISO, such as the Midwest ISO, with a high degree of independence, and the authority to operate the transmission grid as a unified network, would help to assure that the transmission network operates in a way that serves the users of the network, without unduly favoring the interests of any particular user. The ISO's or Transco's operations must be governed and operated as an independent stand-alone activity, which can be achieved through functional separation of transmission from the generation and distribution aspects of utilities' businesses and independent governance of the ISO or Transco. Importantly, the Midwest ISO meets these tests. The Midwest ISO will be independently governed and will have functional control over a very large transmission system.

Regarding regionalization, the size of the transmission organization should be large enough to exploit any available economies of scope or scale, and to allow the development of as wide a competitive marketplace for electricity as practicable. If the electricity market is balkanized, consumers will not enjoy the full benefits of competition. The Midwest ISO would span parts of 16 states, includes $8.5 billion in gross transmission inve[illegible]00 megawatts of installed generating ca[illegible]. The Midwest ISO has over 69,000 mil[illegible] This regional transmission system is larg[illegible]ally reduce the rate pancaking problem, although additional benefits to consumers might be available as additional utilities were to become members of the Midwest ISO.

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Q. Will the plan provide open, nondiscriminatory, and comparable service?

A. Yes. The Midwest ISO will have to meet the requirements of FERC Order 888 and 889 by providing open, nondiscriminatory, and comparable service and will need to appropriately address transmission pricing issues. Further, the operation of the transmission network by the Midwest ISO would not reduce the safety, adequacy, and reliability of the transmission system.

Rate Unbundling Plan

Q. Please describe the basic standards that a Rate Unbundling Plan should meet.

A. Pursuant to my expertise as an economist and former regulator, I conclude that a rate unbundling plan (and the underlying tariffs) should meet the needs of consumers by facilitating choice and should prevent the distribution utility from exercising vertical market power. All competitors, including affiliates of utilities, should be treated in a comparable manner. CG&E's delivery service and other tariffs should allow for the competitive retail sale of electric power and energy in the manner provided by Ohio legislation while maintaining the safety, adequacy, and reliability of the delivery services system.

Q. Please summarize the Rate Unbundling Plan's role in addressing vertical market power issues.

A. Regulators, and the companies that they regulate, must adequately unbundle rates and tariffs to accommodate retail competition. The absence of sufficient unbundling of the services that had previously been provided on an exclusive, vertically-integrated basis, newly competitive markets would not be effectively open to entry by competitors and choices would therefore not be available to consumers.

CG&E's Rate Unbundling Plan unbundles rates and tariffs in order to meet the needs of consumers and suppliers in newly competitive markets in Ohio while, at the same time, supporting a viable delivery service business.

Q. Please evaluate CG&E's Rate Unbundling Plan based on the objectives you identified earlier. First, will CG&E's Rate Unbundling Plan facilitate choice?

A. Yes. CG&E's Rate Unbundling Plan is consistent with the requirements of Ohio legislation and allows customers to either:

(a) select their own provider of generation services and take T&D services on an unbundled basis; or (b) continue to receive these services from CG&E on a bundled basis. In my view, CG&E has done a credible job of implementing the legislation's requirements in their various proposed rates and tariffs. Most importantly, CG&E's rates and tariffs are designed in a way that can efficiently meet the needs of consumers and suppliers in the emerging competitive market in Ohio and, at the same time, support a viable and sustainable distribution utility business.

Distribution, transmission, other, and generation rates and tariffs are sufficiently unbundled to accommodate competition in the generation and retail electricity businesses, while transmission and distribution remain regulated utility businesses.

Operational Support Plan

Q. Please describe the basic standards that an Operational Support Plan should meet in order to address market power concerns.

A. From my perspective as an economist and former regulator, I believe that an Operational Support Plan should meet the needs of consumers by facilitating choice and should prevent the distribution utility from exercising vertical market power. This plan should allow qualified competitive providers to serve retail customers. All competitors, including affiliates of utilities, should be treated in a comparable manner. The efficiency of these systems is an important consideration: the costs associated with implementing the Operational Support Plan should not be any higher than necessary. Over-investment in operational support systems by a distribution utility could be harmful to consumers if the costs of these systems outweigh the benefits. Importantly, it may be more economical for competitors to develop their own systems.

Q. In terms of market power issues, please briefly describe the Operational Support Plan.

A. The role, opportunities, and risks facing CG&E change markedly once competition in generation commodity and retail markets is introduced. CG&E must provide open, nondiscriminatory, and comparable delivery services to all electricity consumers and suppliers in a retail competition environment. The introduction of retail competition requires that the T&D utility fundamentally change a number of aspects of its operations in order to accommodate retail competition. CG&E will screen potential participants regarding credit risk and to ensure the operational integrity of the distribution system. CG&E will provide training to Certified Suppliers. On an ongoing basis, CG&E will respond to requests for customer information, process enrollment requests, track and report on electric choice activity, provide load profiling information, provide scheduling and settlement services, and provide default service.

To prevent the exercise of vertical market power, investments in systems are needed to support unbundling and the development of competition in retail electricity markets. CG&E must provide open, nondiscriminatory, and comparable delivery services to all electricity consumers and suppliers in a retail competition environment. These systems play a role in ensuring that markets are open to competition.

Q. Will the Operational Support Plan help to provide competitive neutrality?

A. Yes. This plan will put the systems and operations in place that are needed to accommodate retail competition. All qualified competitive providers would be treated symmetrically under the plan.

Under the plan, competitors will have a transparent set of requirements that they must qualify under to enter the market. These requirements can protect against fly-by-night competitors entering the market but are not so high as to present an unreasonable barrier to entry. The resulting openness of entry would support the goal of providing choice to consumers.

Q. Does CG&E's post-restructuring corporate structure allow it to exercise vertical market power?

A. No. The various provisions of CG&E's Transition Plan are sufficient to address legitimate vertical market power concerns.

Horizontal Market Power

Q. Please discuss the horizontal market power issues that arise when electric restructuring is implemented.

A. Horizontal market power concerns arise when there is only one (unregulated) firm, or when a few firms hold a large fraction of the market and where the competitive pressure arising from actual or potential entry by new firms is not sufficient to limit the firms' ability to profitably restrict output and raise the price. In electricity markets, horizontal market power issues concern whether competition in the generation and retailing market in a region will be effective—that is, will some firm or firms in the market have market power such that prices are higher than a fully competitive result?

In CG&E's case, its Transition Plan provides a strong assurance that CG&E, or its affiliates will not be able to exercise horizontal market power. CG&E will become a pure T&D utility while also providing regulated default, standard offer service to customers that choose not to shop; as such, CG&E will not be able to exercise horizontal market power in any market.

The most important consideration in assessing horizontal market power is the ease of entry (openness) of the market. To exercise market power, competitors must not be able to enter the market. Regulation of the essential transmission and distribution systems is aimed directly at making sure that potential competitors *can* enter the market. Other criteria, such as market shares and concentration ratios, can be used to measure the results of the process but taken by themselves they give no indication of whether those entrants are more efficient than incumbents or whether consumers are better off. And, indeed, antitrust regulators use market share analysis only as a first step (or screening test) in deciding whether further market power analysis is merited. Market share is by no means a conclusive indicator of market power, and is likely to be a particularly misleading indicator of horizontal market power when applied to industries with a history of legal monopoly.

Market share analysis and similar criteria can be difficult to actually implement. When market boundaries are blurred, the analyst's decision about whether or not to include particular groups of competitors in the market power analysis can arbitrarily determine the outcome of the market structure investigation. In electricity markets the market boundaries are likely to be particularly difficult to draw and therefore the analysis of effective competition will be controversial. This is another practical reason for policy makers to focus primarily on openness and choice rather than attempting to prescribe how the market will evolve.

Nevertheless, the appropriate antitrust authorities, the Department of Justice and the Federal Trade Commission, will need to carefully monitor electricity power markets and address horizontal market power issues in the generation business if and when they come up.

Q. Should generation be treated like any other competitive business once necessary markets and institutions are in place?

A. Yes. In generation commodity markets, competition should become the major source of protection for consumers. In Ohio, specific legislative targets have been enacted (*e.g.*, the 20% switching target) for the retail sale of electricity—but that should not affect wholesale competition in the electricity commodity.

The introduction of wholesale and retail competition in the electricity commodity is likely to increase efficiency in the production and sale of electricity—perhaps somewhat modestly in the short term, but much more substantially in the longer term—as market processes displace the heavily regulated, central planning oriented procedures used by utilities and most regulators until very recently. The evidence available from other industries to date suggests that as regulation's role recedes, innovation and dynamic efficiency get a significant boost. Ultimately, that is the long-term wellspring of customer benefits.

This view suggests that there will be a continuing—albeit changing—role for regulation of those aspects of the transmission and distribution businesses as long as they retain natural monopoly characteristics. But the generation business—at least on the wholesale level, given Ohio's retail switching target—should become a competitive business, subject to the same oversight as other competitive businesses.

Market Share Is Not The Same As Market Power

Q. Should large market share be equated with horizontal market power?

A. No. Equating market share with market power is a common error. If the incumbent cannot raise prices or restrict output without losing market share—because markets are open and choice is available to consumers—then there is no significant market power. The mere fact that utilities' presently have a large share of the regulated retail electricity market within their service territories will not tilt the competitive market in favor of the utilities so long as the retail market is open to entry and customers have the freedom to choose their retail provider for themselves.

First, electric utilities will not be competitors in the retail electricity market. They will provide standard offer and default service, but only if a customer does not make an affirmative choice to select a competitive provider. In addition, they will be regulated in this role and will therefore have no opportunity to exercise market power. The utilities' marketing affiliates will start with zero market share—just like all other entrants.

Second, once the retail market is opened to competition, the relevant market will become broader than any individual distribution utility's service area. When the market is opened, all incumbents' market shares will automatically drop, even if they retain the same number of customers.

Finally, market *share* is not a reliable indicator of market *power*. Even in anti-trust policy, the existence of high market shares does not automatically lead to a finding that market power exists. A finding of high market shares can trigger more detailed, empirical investigations of potential market power. (*Department of Justice and Federal Trade Commission Horizontal Merger Guidelines* (DOJ), April 2, 1992, pp. 5-6.) The focus of that subsequent analysis is on identifying whether or not significant barriers to entry exist. The anti-trust authorities themselves acknowledge that high levels of structural concentration do not, by themselves, indicate the existence of market power. Researchers at the U.S. DOJ have found that structural concentration metrics are extremely poor predictors of the actual harm to competition and consumers arising from the abuse of market power. (Gregory Werden and Luke Froeb, "Simulation as an Alternative to Structural Merger Policy in Differentiated Products Industries," chapter 4 in *The Economics of the Antitrust Process*, edited by Malcolm Coate and Andrew Kleit, Boston: Kluwer Academic Press, 1996.)

If the incumbent cannot raise prices or restrict output without losing market share, then there is no significant market power. Moreover, incumbency by itself does not necessarily confer market power. Critical to establishing and exercising market power is that competitors not be able to enter the market in response to price increases. Importantly, regulation of the essential transmission and distribution systems is aimed precisely at ensuring that potential competitors can enter the market.

In sum, if the incumbent cannot raise prices or restrict output without losing market share, then there is no significant market power. Moreover, incumbency by itself does not necessarily confer market power. Critical to establishing and exercising market power is that competitors not be able to enter the market in response to price increases by the incumbent. Importantly, regulation of the essential transmission and distribution systems is aimed precisely at ensuring that potential competitors can enter the market.

CUSTOMERS' CHOICE TO NOT SWITCH DOES NOT MEAN THERE IS A MARKET POWER PROBLEM

Q. Is customer inertia a source of market power?

A. No. While it is simply wrong to interpret a customer's decision not to switch energy providers as a failure of customer choice, some participants in the regulatory process may make this argument if they believe that sufficient numbers of customers have not switched. Correctly viewed, a customer's decision not to switch energy suppliers is itself a manifestation of customer choice, and reflects a weighing of the benefits of switching on the one hand, and the transaction costs of choosing on the other. Concern is sometimes expressed that residential and small commercial customers will not be effective consumers of gas or electricity, whether because they are excessively loyal to their traditional supplier, because they are poorly informed, or simply because such customers are irrational. For these reasons, it is sometimes argued, customers will not switch suppliers even if it would be rational (in the critics' opinion) for them to do so, and this customer inertia allegedly gives the incumbent utility company market power. Policies and mechanisms are then developed to manage this perceived problem. Well-designed customer education programs can play a useful role in addressing the concern that customer inertia is some sort of markets failure. In taking these steps, however, regulators must take care to avoid unnecessary and inefficient distortions in the workings of competitive markets.

The argument that customer inertia is a form of market power seems to be an ironically paternalistic view of the consumer, given the context of restructuring, for it strikes at the heart of the policy question of whether competitive markets, and the opportunities for choice associated with them, are desirable. Competition will raise somewhat the cost to consumers of gathering and processing information. It is likely that some small consumers—in contrast, for example, to large industrial customers, who have more to gain or lose—will not necessarily want to invest substantial time to make themselves better able to navigate the energy market. It seems reasonable to assume that consumers will behave in the energy market much as they do in other markets, devoting more attention to some markets, and less to others. And, in fact, that is a sensible way to behave. There may be a role for the regulator to ensure that consumer education is provided, but there is no legitimate role for government to supersede through interventionist policies the consumer's right to choose his or her own supplier.

The argument that a customer's decision not to switch energy providers is evidence of market power turns normal economic reasoning upside down. Customer choice in this newly opened market does not create market power or any other kind of market imperfection. Upon opening the market, one must honor the *customer's* choice, including the choice of standing pat.

Q. Does customer loyalty to their traditional supplier create a market failure?

A. No. The suggestion that customer loyalty will interfere with the working of the market is also wrong. Customer loyalty to an energy supplier is no more evidence of serious market failure than is their loyalty to brand name products elsewhere in the consumer goods sector. To deprive consumers of their ability to maintain this loyalty (*e.g.*, by barring the company from the market or other similar interventionist policies) would destroy any value the customers derive from this commercial relationship.

THE COMPETITIVE PLAYING FIELD SHOULD NOT BE TILTED

Q. Should regulators attempt to encourage entrants by tilting the competitive playing field?

A. No. Reliance on competitive markets is based on the principle that any firm that can produce most efficiently based on forward-looking costs, and bring the most value to consumers, should (and, in an evenhanded setting, will) prevail. Thus, an economic advantage in satisfying the needs of consumers possessed by one competitor, but not by others, is not anti-competitive. It simply reflects the different skills and endowments that each and every firm brings to the market, including differences in their overall cost of doing business. Even in competition, firms, like people, are not just peas in a pod. Moreover, one of the most important lessons of competitive markets in other restructured industries is that today's advantage can be a fleeting phenomenon. Success either in entering the market, or in retaining any existing market share, is not guaranteed, even in industries with a long regulatory history.

Q. Is there a danger that Ohio may forego some of the benefits of competition if it does not implement rules that handicap the utility companies?

A. No. The concern that potential entrants will be scared off if restructuring rules do not give them preferential treatment is not valid. Potential entrants to Ohio's electric retail markets are not small, unsophisticated companies in need of strong governmental support and protection. There may indeed be some such start up entrants in newly opened electricity markets. However, among the likeliest candidates for entry are the large integrated energy companies that have come to dominate these markets over the past few years.

In the early days of energy marketing there were some pure marketing companies but there has been a strong consolidation of the marketing sector in recent years. The largest 20 or more marketing companies are huge, diversified, vertically and horizontally integrated energy companies—such as Enron, Statoil, Dynegy, UtiliCorp and others—have affiliates engaged in a wide range of businesses, including regulated gas and electricity distributorships, exploration & production of oil and gas, natural gas pipelines, electricity generation, independent power plant construction and operation, and energy service companies. These companies are among the likely candidates to enter the Ohio retail market. They have broad reach, deep pockets, and substantial marketing sophistication. They will face none of the barriers that many utilities' affiliates will face as a result of standards of conduct that are being implemented in many states. Marketers do not need to be specially protected in the marketplace, once their access to the necessary wires on a non-discriminatory basis has been assured.

Policies that distort the competitive pressure faced by some firms would weaken the efficiency of competition. This might be good for some competitors but would raise the prices paid by consumers and would reduce social welfare. Policy makers should seek to promote consumer welfare via efficient competition, and should be careful not to artificially promote the competitive interests of any particular category of competitors. Pro-consumer policies provide strong incentives for productive efficiency, which benefits consumers (by providing low prices) and society (by encouraging efficient use of scarce resources). Policies that artificially limit the competition faced by some firms would weaken the robustness and efficiency of competition and would thereby allow competitors to earn economic rents. This might be good for the competitors but would raise the prices paid by consumers and would reduce social welfare.

THE MARKET STRUCTURE SHOULD BE ALLOWED TO EVOLVE

Q. **Can regulators expect the market to be fully developed at the outset?**

A. No. Regulation that aims at specifying in advance the structure of the industry strikes at the core of the reason for relying on unregulated competitive markets. An essential element of such markets is that anyone who wishes to enter the market can do so, bringing whatever special capabilities or resources they may have to the task. It is by this process that the efficiencies associated with scope and scale are discovered and realized. Only by relying on markets in which firms are free to make their own decisions about what to produce or not produce will this discovery take place. The 1997 Economic Report of the President noted:

> An insufficiently appreciated property of markets is their ability to collect and distribute information on costs and benefits in a way that enables buyers and sellers to make effective, responsive decisions. As tastes, technology, and resource availability change, market prices will change in corresponding ways, to direct resources to the newly valued ends and away from obsolete means. It is simply impossible for governments to duplicate and utilize the massive amount of information exchanged and acted upon daily by the millions of participants in the marketplace.

Government-imposed market structures or targets force society to forego the benefits that can be achieved by allowing producers and consumers to discover the most efficient market arrangements. Of course, where regulated firms are involved in these processes, protections for customers, such as restrictions on use of essential facilities and improper subsidies are certainly appropriate. But needed protection can be accomplished by relying upon targeted approaches (*e.g.*, codes of conduct and affiliate transaction oversight) without sacrificing available economies.

Market structures should evolve through customers' demands and firms' responses to them, not by regulatory planning and design. If regulators succeed in creating an effective open access competitive environment, then those firms that are most efficient at attracting and meeting the needs of consumers will be successful. Even more importantly, consumers will be able get what they want at favorable prices. But the real economic benefits of increased efficiency of the industry will only come as firms reorganize their structures and operations. This takes time—and some patience on the part of policy makers.

On the other hand, if markets are not efficiently opened to entry, no amount of handicapping the incumbent, or giving a leg up to entrants, will guarantee a more efficient result for consumers. Indeed, the success of less efficient providers is more likely. That outcome would be the antithesis of what the drive to open markets to consumer choice is all about. In short, policies that strive to enhance the efficiency of the competitive process will be helpful, while policies that directly influence specific industry structures and outcomes will not, and should be avoided.

OTHER TRANSITION ISSUES

Q. Please explain the ratemaking issue regarding the gross receipts tax that you will address?

A. CG&E is seeking to recover the Gross Receipts Tax for the tax year ending April 30, 2002 in rates. CG&E's request matches the recovery of the Gross Receipts Tax in rates with the year in which CG&E incurred the tax expense. This is a sensible approach, which is consistent with reasonable ratemaking principles.

Q. Is it a reasonable ratemaking practice to allow for recovery in rates in the year before CG&E expenses and completes payment of the gross receipts tax (otherwise known as the measurement year)?

A. No. Allowing a utility early recovery of an expense is not a reasonable ratemaking methodology. Because there is no evidence that the Commission has ever allowed early recovery, during the measurement year, of the gross receipts tax, the Commission should allow CG&E to recover the gross receipts tax for the privilege of doing business in the year ending April 30, 2002, through the temporary rider ending April 30, 2002, shown as schedule UNB-1 appended to John P. Steffen's testimony. This recovery methodology is consistent with the ratemaking principle of matching, which this Commission and other regulatory agencies rely upon in setting utility rates.

Because I view it as unreasonable for a regulator to allow early recovery of the Gross Receipts Tax in conflict with standard ratemaking principles, I find that any argument that the measurement period and not the privilege period should be used to be unpersuasive. After all, why would regulators allow a utility to recover costs a year prior to the utility actually incurring those costs? The basic concept of known and measurable would not, in my view, support this approach. At a minimum, if this approach had been used—which would have provided a benefit to the utility by requiring ratepayers to pay a cost one year early—I would at least expect to see a clear explanation by the Commission explaining why this approach was reasonable.

Q. Are you aware of any evidence that CG&E was allowed to recover its gross receipts tax expense in the measurement year?

A. No. My understanding is that a search of the Commission archives (performed by attorneys for CG&E) relating to the implementation of the Gross Receipts Tax in 1893 and 1910, does not indicate that the Commission allowed recovery in the measurement year. Similarly, I understand that a search of the archives does not indicate that the Commission allowed recovery during the privilege year. I have reviewed the pertinent Commission Orders and am satisfied that there is no clear answer regarding the original and ongoing ratemaking treatment for the recovery of the Gross Receipts Tax by CG&E.

Given the absence of clear evidence, I believe that it is reasonable to assume that the Commission would have matched recovery to the year of payment and expense by the utility, consistent with standard ratemaking practices.

Q. Does this conclude your direct testimony?

A. Yes.

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Dr. Kenneth Gordon is a Senior Vice President with National Economic Research Associates, specializing in utility regulation and related issues. He was Chairman of the Massachusetts Department of Public Utilities from January 1993 to October of 1995. He came to the Massachusetts Commission from the Maine Public Utilities Commission, where he also held the office of Chairman from 1988 through the end of 1992. Prior to that, he was an Industry Economist at the Federal Communications Commission's Office of Plans and Policies. Prior to that, he taught at several colleges since 1965, the most recent position having been at Smith College.

Dr. Gordon was an active member of the National Association of Regulatory Utility Commissioners (NARUC) and served as president of that organization in 1992. He was also a member of the Executive Committee, and the Committee on Communications of NARUC. He has served as Chairman of the New England Conference of Public Utilities Commissioners Telecommunications Committee, and is a former Chairman of the Power Planning Committee of the New England Governors' Conference. He currently also serves on several boards and committees. Dr. Gordon has authored a number of publications and lectures widely on topics related to utility regulation.

Dr. Gordon is a graduate of Dartmouth College and holds a doctorate in economics from the University of Chicago.

EDUCATION

University of Chicago	Ph.D	1973
University of Chicago	M.A.	1963
Dartmouth College	A.B.	1960

EMPLOYMENT

November 1995 - **National Economic Research Associates, Inc.**, Washington, D.C.
Senior Vice President

October 1995 **Consulting Economist**

January 1993 - October 1995 **Massachusetts Department of Public Utilities**
Chairman

October 1988- December 1992 **Maine Public Utilities Commission**
Chairman

1980 - 1988 **Federal Communications Commission, Office of Plans and Policy**
Industry Economist

1965 - 1980 **University and College Teaching** (most recently at Smith College)

1963 - 1964 **University of Chicago**
Research Associate

CURRENT APPOINTMENTS AND MEMBERSHIPS

Telecommunications Policy Research Conference
Chair, 1995-1996
Board Member, 1994

Energy Modeling Forum (EMF 15, A Competitive Electricity Industry),
Stanford University
Member

American Economic Association

Transportation and Public Utilities Group, AEA

PAST APPOINTMENTS AND MEMBERSHIPS

National Association of Regulatory Utility Commissioners
Communications Committee, 1990 - 1995
Executive Committee, 1991-1995
President, 1992

New England Conference of Public Utility Commissioners
Power Planning Committee
Chairman

Governor's Electric Utility Market Reform Task Force
Co-Chairman

Boston University Telecommunications Forum
Advisor

Center for Public Resources, Legal Program to Develop Alternatives to Litigation
Chairman, Utilities Committee

Office of Technology Assessment, Advisory Panel on International Telecommunications Networks

Bellcore Advisory Committee,
Member and Chairman, 1993 to 1996.

ACTIVITIES

Participant in numerous regional and state committees, organizations, and task forces.

Participant in various NARUC/DOE conferences on gas and electricity issues.

Frequent speaker on electric, telephone and environmental issues nationally.

TESTIMONIES

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: reply testimony on "code of conduct" issues, filed October 26, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: rebuttal testimony addressing the pricing of metering and billing services, filed October 21, 1999.

Before the Maine Public Utility Commission, on behalf of CMP Group, Inc.: rebuttal testimony on issues related to acquisition of CMP by Energy East, filed October 13, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: direct testimony addressing the proper pricing of metering and billing services, filed October 8, 1999.

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: direct testimony on "code of conduct" issues, filed October 1, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: direct testimony addressing the proposed alternative ratemaking plan, filed September 30, 1999.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: direct testimony regarding economic consequences resulting from full avoided cost discount as applied to resale of existing contracts, filed September 27, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: direct testimony on the acquisition of CMP by Energy East, filed July 1, 1999.

Before the Illinois Commerce Commission, on behalf of Commonwealth Edison: rebuttal testimony addressing the design of delivery services tariffs, filed May 10, 1999.

Before the Subcommittee on Energy and Power, on behalf of National Economic Research Associates: statement addressing electric restructuring market power issues, filed May 6, 1999.

Before the New Jersey Public Utilities Board, on behalf of the Edison Electric Institute: direct testimony on the PUC's draft affiliate relations standards, filed May 3, 1999.

Expert report, on behalf of ICG/Teleport addressing the way in which Denver's ordinance allocates costs among users of public rights-of-way, filed April 21, 1999.

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INCIDENTAL TEACHING AND LECTURING

University and College
Yale School of Management and Organization
Harvard Law School, Telecommunications Seminar
Suffolk University Law School
University of Maine
Boston University

Other
Edison Electric Institute
(Electricity Consumers Resource Council)

December 2, 1999

CG&E EXHIBIT 20

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION	)	
OF THE CINCINNATI GAS & ELECTRIC	)	
COMPANY FOR APPROVAL OF ITS	)	CASE NO. 99-1658- EL-ETP
ELECTRIC TRANSITION PLAN	)	

DIRECT TESTIMONY OF

JOHN C. PROCARIO

ON BEHALF OF

THE CINCINNATI GAS & ELECTRIC COMPANY

DIRECT TESTIMONY OF JOHN C. PROCARIO

Q. Please state your name and business address.

A. My name is John C. Procario and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. By whom are you employed and in what capacity?

A. I am employed by Cinergy Services Inc. (Cinergy Services), a service company subsidiary wholly owned by Cinergy Corp. (Cinergy), as Vice President of Electric Operations.

Q. What are your duties and responsibilities as Vice President of Electric Operations?

A. As Vice President of Electric Operations, I am responsible for the planning, engineering, operation, maintenance, and construction of the electric transmission and distribution systems of the Cinergy domestic utility subsidiaries (i.e., PSI Energy, Inc. (PSI) and The Cincinnati Gas & Electric Company (CG&E), including The Union Light, Heat & Power Company (ULH&P), a subsidiary of CG&E). I also am responsible for the control area operations and the administration of the energy delivery contracts and tariffs of the Cinergy domestic utility subsidiaries.

Q. Please briefly describe your professional and educational background.

A. I received a BS degree in electrical engineering from Ohio State University in 1973. I was awarded an Ohio Electric Utility Institute Fellowship and graduated with an MS degree in the electric power program from Ohio State University in 1974. I also have taken approximately 30 credit hours in the MBA program at the University of Cincinnati.

I began my professional career with CG&E in 1974 and have held various engineering and managerial positions, including Manager of Electric Planning and Manager of Electric System Operations. After the merger of PSI and CG&E to form Cinergy in 1994, I became General Manager of Electric System operations for the Cinergy domestic utility subsidiaries. In August of 1996, I was promoted to Vice President of Electric System Operations. I was recently promoted to my current position of Vice President of Electric Operations.

I have also taught a series of electric power systems courses in the College of Engineering at the University of Cincinnati, starting as a Lecturer in 1975 and progressing to Adjunct Professor.

I am or have been a member of various industry committees and organizations, including the East Central Area Reliability (ECAR) Executive Board, the North American Electric Reliability

Council (NERC) Engineering Committee, and the EPRI Electrical Systems Division Committee.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to adopt, sponsor and explain the Independent Transmission Plan, which is Part G, of CG&E's Transition Plan. This is CG&E's component plan for complying with R. C. 4928.12, which requires independent control of CG&E's transmission facilities. I will explain how the Independent Transmission Plan fulfills the statutory requirement to transfer CG&E's transmission facilities to a "qualifying transmission entity." My testimony will explain in detail how CG&E's participation in the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) satisfies each element of the nine-factor "qualifying transmission entity" test as set forth in the statute. The Independent Transmission Plan was prepared at my direction and under my supervision. It accurately describes the steps that CG&E will take to comply with R. C. 4928.12. The Independent Transmission Plan contains a separate set of the following appendices, which support the Plan itself: Appendix I- *In re Midwest Independent Transmission System Operator, Inc., 84 FERC ¶ 61,231; 1998 FERC LEXIS 1812 (September 16, 1998),* which was the initial order of the Federal Energy Regulatory Commission (FERC) conditionally approving the Midwest ISO;

Appendix II - *In re Midwest Independent Transmission System Operator, Inc., 85 FERC ¶ 61,372; 1998 FERC LEXIS 2510 (December 17, 1998),* which was another FERC order approving certain aspects of the Midwest ISO; Appendix III - *In re Midwest Independent Transmission System Operator, Inc., 87 FERC ¶ 61,085; 1999 FERC LEXIS 763 (April 16, 1999),* which was the final FERC order granting approval to the Midwest ISO, conditional upon a compliance filing; Appendix IV – the Midwest ISO compliance filing with FERC, filed May 17, 1999, which was the Midwest ISO's compliance filing in response to the April 16, 1999 FERC order granting conditional approval to the Midwest ISO; Appendix V – Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., which sets forth the organizational framework for the Midwest ISO; Appendix VI – Midwest ISO Appendix I which allows Independent Transmission Companies to join the Midwest ISO; Appendix VII – Open Access Transmission Tariff for the Midwest Independent Transmission System Operator, Inc., which describes the manner in which the Midwest ISO will deliver services and the rates it will charge; Appendix VIII – a map showing the Midwest ISO's current participating transmission owners. I am familiar with these appendices and they are true and authentic copies of the original orders and documents I have described.

Background of the Midwest ISO

Q. Please describe your involvement with the development of the Midwest ISO.

A. I was involved in the discussions beginning in 1995 resulting in the development of the Midwest ISO. The participating transmission owners filed for approval with FERC on January 15, 1998.

For much of the time until the January 1998 filing, as well as after, I served as Chairman of the Midwest ISO Management Council. Today, as the Midwest ISO Board of Directors is now in place, I serve as Chairman for both the Midwest ISO Advisory Committee and the Transmission Owners Committee. The Advisory Committee consists of representatives from each of the Midwest ISO stakeholder groups, and the Transmission Owners Committee consists of representatives from transmission owning entities that are signatories to the Midwest ISO agreements.

Q. Please generally describe the Midwest ISO.

A. The Midwest ISO is an independent, non-profit, non-stock, tax-exempt Delaware corporation that will have functional control for the transmission facilities of its participating transmission owners. The organization received conditional FERC approval on September 16, 1998. The purpose of the Midwest ISO is to provide open access to a large regional transmission system, achieve greater reliability, alleviate transmission constraints, and provide transmission service over the entire Midwest ISO system at unbundled, non-pancaked rates.

Q. Who are the participating transmission owners?

A. The transmission owners currently participating in the Midwest ISO are the following group of diverse public and private utilities: Cinergy Corp. (on behalf of CG&E, PSI and ULH&P), Commonwealth Edison Company (including Commonwealth Edison Company of Indiana), Wisconsin Electric Power Company, Hoosier Energy Rural Electric Cooperative, Inc., Wabash Valley Power Association, Inc., Ameren (on behalf of Central Illinois Public Service Company and Union Electric Company), Kentucky Utilities Company, Louisville Gas & Electric Company, Illinois Power Company, Central Illinois Light Company, Southern Illinois Power Cooperative, Sigcorp. (on behalf of Southern Indiana Gas & Electric Company), Allegheny Power Systems and Alliant Energy.

In addition, Northern States Power recently joined the Midwest ISO as a participating transmission owner. The Mid-Continent Area Power Pool (MAPP) and the Southwest Power Pool (SPP) have also recently signed memoranda of understanding concerning the merger of those organizations with the Midwest ISO.

Q. Who are the members of the Midwest ISO besides the participating transmission owners?

A. In addition to the current participating transmission owners, the current members of the Midwest ISO are: Wisconsin Public Power, Inc., Illinois Municipal Electric Agency, American Municipal Power-Ohio, Inc., Reliant Energy, Inc., Citizens Power Sales, Granite City Steel Division, National Steel Corporation, Consumers Energy Company, Cleveland Public Power, Department of Public Utilities, Constellation Power Source, Inc., Air Products and Chemicals, Inc., Automated Power Exchange, Inc., American Electric Power Company, Electric Clearinghouse, Inc., U. S. Generating Company, PG&E Energy Trading-Power, L.P., FirstEnergy Corp., Detroit Edison Company and Edison Mission Marketing & Trading, Inc.

Q. How large will the Midwest ISO be once it becomes operational?

A. As it is currently comprised, the Midwest ISO spans parts of 16 states and three regional reliability councils: MAIN, ECAR and MAPP. The Midwest ISO includes $8.5 billion in gross transmission investment, and has 91,000 megawatts of installed generating capacity in its service area. The Midwest ISO has over 69,000 miles of transmission lines. The Midwest ISO is open to additional members and, in my opinion, should include, at a minimum, all the major owners of transmission facilities within the MAIN and ECAR reliability regions.

Q. Please describe the relationship between the participating transmission owners and the Midwest ISO.

A. The participants who own transmission facilities retain ownership over their transmission facilities, but will transfer functional control to the Midwest ISO over their network transmission facilities over 100 kV and their network transformers with two or more voltages over 100 kV. The participants have authorized the Midwest ISO to offer non-discriminatory open access transmission service, to collect and distribute transmission revenues and to provide system reliability and security. The transmission owners will actually continue to operate and maintain their transmission lines within their own control areas.

Q. What will happen with the existing control areas?

A. The existing generation control areas will continue to be under the operation of the transmission owners for the purposes of matching generation and load. The Midwest ISO will only have the authority to affect generation dispatch to the extent that it affects reliability or system security. The Midwest ISO may direct the participants in matters such as re-dispatching generation, curtailing load and controlling voltage so that the Midwest ISO can maintain adequate system reliability.

Q. What major functions will the Midwest ISO perform?

A. The Midwest ISO will perform several services for the users of the transmission system, including tariff administration and acting as the regional security coordinator for those systems under its control. The Midwest ISO will operate a transmission security center to control operation of the Midwest ISO's transmission system. It will not operate a single generation control area for the region. The transmission owners that operate generation control areas today will continue to do so and will balance load and generation in their control areas. However, the Midwest ISO will operate a single transmission-reliability control area for the region.

Q. Which entity will calculate available transfer capability (ATC)?

A. The Midwest ISO will calculate and disseminate ATC for the system. It will process users' requests to reserve transmission service. It will coordinate the ATC with existing energy schedules. It will perform actual transaction flow calculations to determine system energy losses and allocate revenues. It will also perform accounting for inadvertent use of energy.

Q. Has the Midwest ISO received FERC approval?

A. Yes, as I previously mentioned, the Midwest ISO initially received conditional approval from FERC on September 16, 1998. The Midwest ISO made compliance filings and FERC ultimately approved the Midwest ISO on April 16, 1999, conditional on a compliance filing that the Midwest ISO made on May 17, 1999. The Midwest ISO still must make additional filings within 60 days of operations to provide various operating procedures and other documents to FERC.

Q. **What is the current status of the Midwest ISO from an organizational and development standpoint?**

A. The members elected an independent Board of Directors in December, 1998 and the Board recently employed Dr. Matthew Cordaro as President and CEO of the Midwest ISO. The Midwest ISO's control center will be located at a site in Carmel, Indiana, just north of Indianapolis. The transmission owners will transfer operational control of their transmission facilities to the Midwest ISO as soon as the Midwest ISO is able to complete a technical demonstration to establish that it can provide the services enumerated under its tariff. The Midwest ISO is scheduled to become operational in 2001.

The "Qualifying Transmission Entity" Test

Q. **Are you familiar with the requirements of R. C. 4928.12 and 4928.35 that relate to an electric utility company's Independent Transmission Plan?**

A. Yes.

Q. **Do you have an opinion as to whether CG&E's Independent Transmission Plan complies with the requirements of R. C.**

4928.12 and 4928.35 that relate to an electric utility company's Independent Transmission Plan?

A. Yes, I have an opinion.

Q. What is your opinion?

A. In my opinion, CG&E's Independent Transmission Plan complies with the requirements of R. C. 4928.12 and 4928.35 that relate to an electric utility company's Independent Transmission Plan. Revised Code Section 4928.12 provides that, after the starting date for competitive retail electric service, no electric utility company shall own or control transmission facilities located in Ohio unless the utility is a member of and transfers control of its transmission facilities to a "qualifying transmission entity" that is operational. The statute defines a qualifying transmission entity as a transmission entity that (1) is approved by FERC; (2) effects separate control of transmission facilities from control of generation facilities; (3) implements policies and procedures designed to minimize pancaked transmission rates within Ohio; (4) improves service reliability in Ohio; (5) facilitates an open and competitive electric generation marketplace, eliminates barriers to market entry and precludes control of bottleneck electric transmission facilities in the provision of retail electric service; (6) is of sufficient scope or otherwise substantially increases economical supply options for consumers; (7) has a governance structure or control that is independent of the users of the transmission facilities, and no member of its Board of Directors is affiliated with such a user or user's affiliate during the member's tenure on the Board, such as to unduly affect the transmission entity's performance; (8) operates under policies that promote positive performance designed to satisfy the electricity requirements of customers; and (9) is capable of maintaining real-time reliability of the electric transmission system, ensuring comparable and non-discriminatory transmission access and necessary services, minimizing system congestion, and further addressing real or potential transmission constraints. CG&E has agreed to transfer functional control of its covered transmission facilities to the Midwest ISO, which meets the nine statutory requirements for a qualifying transmission entity. The Midwest ISO is not currently operational. Revised Code Section 4928.35(G) provides that if the qualifying transmission entity is not operational as of the starting date of competitive retail electric service, then the Commission shall order the electric utility company to be a member of a qualifying transmission entity that will be operational by December 31, 2003. The Midwest ISO is scheduled to be operational in 2001; therefore, CG&E is in compliance with these statutory requirements, conditional on the Midwest ISO becoming operational prior to December 31, 2003.

(1) Approval by Federal Energy Regulatory Commission

Q. When did the Midwest ISO file for approval with the FERC?

A. On January 15, 1998, the original participants in the Midwest ISO applied to FERC for permission to transfer functional control of operation of their covered transmission facilities to the Midwest ISO. FERC opened Docket Nos. ER98-1438-000 and EC98-24-000 to review the application. FERC issued an order conditionally authorizing the establishment of the Midwest ISO, and accepted the filing of its tariff and operating agreement, on September 16, 1998. The Midwest ISO participants subsequently modified their tariff and operating agreement to comply with FERC orders. FERC issued another order on April 16, 1999, accepting the Midwest ISO tariff and operating agreement, conditioned on a compliance filing to be made within 30 days. *In re Midwest Transmission System Operator, Inc., 87 F.E.R.C. 61,085, 1999 FERC LEXIS 763 (1999).* The members of the Midwest ISO made this compliance filing on May 17, 1999, thus fulfilling all FERC requirements for approval of the Midwest ISO. The Midwest ISO filing was developed to comply with all applicable FERC pronouncements and orders. This filing, as modified, complies with FERC's eleven ISO principles announced in Order No. 888. The only other filing requirements that have been imposed on the Midwest ISO relate to operational matters.

In addition, the Midwest ISO specifically tailored the pricing approach and its governance procedures to be consistent with FERC orders on other ISO filings. In fact, on the two primary issues, governance and pricing, the structures in the filing were very similar to structures the FERC found to be appropriate in the *Pennsylvania – New Jersey – Maryland Interconnection, 81 FERC 61,257, 1997 FERC LEXIS 2576 (Nov. 25, 1997) ("PJM-II") slip op. at 32-35, 61-63.*

(2) Separate Control of Transmission Facilities From Generation Facilities

Q. What guiding principles did FERC promulgate in Order No. 888 for the establishment of ISOs regarding separate operational control of transmission facilities from generation facilities?

A. There were two principles designed to promote separate control of transmission facilities from generation facilities. The first principle requires that the ISO must have functional operational control over the transmission facilities within the area where it operates. The second principle prohibits the ISO and its employees from having any financial interest in the economic performance of the ISO participants. The Midwest ISO filings complied with these two principles in order to obtain FERC approval.

Q. What is meant by the term "functional control" of transmission facilities?

A. While the Midwest ISO participants will not transfer ownership of their transmission facilities to the ISO, they will transfer functional control of their facilities to the Midwest ISO. This will allow the Midwest ISO to direct the participants' operation of their transmission systems. However, the Midwest ISO has proposed changes to its agreements which would allow independent transmission companies (ITC) to exist under an ISO structure by filing an Appendix I, which will allow for this structural flexibility. Pursuant to the new Appendix I, an ITC under the Midwest ISO may exercise some operational control, subject to FERC approval. The Midwest ISO will also be charged with calculating ATC, maintaining OASIS information and approving requests for transmission service. As a result of CG&E's membership in the Midwest ISO, the functional control over CG&E's transmission facilities will be separated from its generating plants.

Q. Over which transmission facilities will the Midwest ISO assert functional control?

A. By separate application, the transmission owners have sought to transfer control of their looped transmission facilities above 100kV and certain networked transformers to the Midwest ISO. Once that transfer is in effect and the Midwest ISO is operating, the Midwest ISO will control the significant interconnected transmission facilities within the Midwest ISO region. If the

Midwest ISO determines that other facilities are necessary to ensure reliable transmission system operations, then the Midwest ISO will be able to cause the initiation of procedures to obtain control of those facilities as well. The Midwest ISO will control the operations of looped transmission facilities above 100kV and networked transformers with two voltages above 100kV. By the filing under section 203 of the Federal Power Act, the participating Midwest ISO transmission owners will transfer control of these facilities to the Midwest ISO upon commencement of operations. While the Midwest ISO takes on considerable functional responsibility for the transmission system, it will not physically operate the switches or take other similar actions. The Midwest ISO will direct the transmission owners to take the necessary actions.

Q. How will the Midwest ISO handle the construction of additional transmission facilities it deems necessary?

A. The participating transmission owners established provisions in the tariff that help ensure that entities constructing facilities are fully compensated for their efforts though the FERC's orders on this issue create some uncertainty. Full recovery is particularly important in the context of an ISO, as the ISO will be ordering the construction of facilities. If the new facilities are proposed for the control area of a participating transmission owner, then that owner will have the option of financing and constructing the facilities. If the transmission owner elects not to finance construction of the new facilities, then another participating transmission owner may opt to finance construction and receive appropriate compensation. Additionally, all participating transmission owners potentially could jointly finance the transmission system expansion.

Q. How will compensation for transmission system upgrades be handled?

A. For the transition period (the first six years after commencement of operations), FERC will determine on a case-by-case basis whether the point-to-point transmission customer who caused the upgrade will pay an annual carrying charge on the facilities, in addition to the applicable transmission rate. Based upon the FERC's orders, it is unclear at this time whether FERC will cause the customer to pay both for the upgrade and the embedded cost of the facility. Beginning in year seven, all network upgrades, including network upgrades constructed during the transition period, will be rolled-in to the base transmission rates. As all load at that time will be under the Midwest ISO, owners will receive a reasonable assurance of full revenue recovery. In order to prevent this rolled-in approach from being abused and from more economic choices being ignored, the Midwest ISO will not require construction if there are more economic (on a Midwest ISO-wide basis) alternatives to the construction of new facilities. Under the Midwest ISO tariff, facilities which are considered direct assignment facilities, as compared to network upgrades, will be paid for by the customers responsible for the construction of those facilities, and those customers also will pay the transmission charge under the tariff.

Q. Does the Midwest ISO have the ability to administer and file proposed changes to its tariff independently?

A. Yes. The Midwest ISO is the sole administrator of its tariff. The Midwest ISO and potentially an ITC will have the autonomy to file changes to its tariff and to make compliance filings unrelated to rates. The participating transmission owners retain independent control over their ability to file changes to the rate schedules in the tariff involving the base transmission charges. FERC has jurisdiction to determine whether any rate changes filed by the participating transmission owners are just and reasonable.

Q. To what extent will the Midwest ISO have operational responsibility for the participating transmission owners' transmission facilities?

A. "Operational responsibility" is somewhat of an unclear term. Each participating transmission owner in the Midwest ISO retains operational responsibility for field operations, such as switching and circuit breaker operations. The participating transmission owners transfer functional control over their covered transmission facilities to the Midwest ISO; therefore, there is no need for the Midwest ISO to have operational control. The Midwest ISO does not require physical control as long as it has authority over operations. The Midwest ISO has functional control over each participating transmission owners' covered facilities, defined as transmission facilities operated at above 100kV and any other facilities which are necessary to relieve a constraint or for security purposes, including facilities which have a significant affect on ATC.

Q. Please describe how the Midwest ISO will operate as a control area.

A. The Midwest ISO will not be operated as a single control area. A single control area for the Midwest ISO for the purpose of dispatching generation would be a monumentally expensive task requiring large amounts of hardware, software and communications links. Instead, the Midwest ISO will be a single transmission control area. Initially, the current generation control areas will remain intact and operate as they do today. FERC required that the Midwest ISO submit a study within 18 months after operations begin on the relationship between the Midwest ISO and the control areas.

Q. Will the Midwest ISO have authority to order that additional facilities be transferred to its control?

A. Yes. As I previously stated, the Midwest ISO will have authority to order participating transmission owners to transfer to the Midwest ISO additional transmission facilities necessary for system reliability.

(3) Minimization of Pancaked Rates

Q. Please describe FERC's requirements regarding the elimination of transmission rate pancaking.

A. FERC's ISO principles include a requirement that the ISO provide open access to the transmission system and all related services under a single, unbundled grid-wide tariff at non-pancaked base transmission rates.

Q. Does the Midwest ISO's result in transmission customers within Ohio paying multiple access charges over the transmission facilities controlled by the Midwest ISO in Ohio?

A. No. The Midwest ISO tariff provides for network transmission service and point-to point service consistent with the provisions of the *pro forma* tariff at non-pancaked zonal rates during a six-year transition period.

Q. What is meant by the term zonal or license plate pricing?

A. During the transition period, zonal rates based on the transmission owners' zones and costs have been adopted. The zonal rates apply to transmission service involving load within the zone. Payment of the zonal rate allows the customer to use the entire Midwest ISO network without paying another base transmission charge. A single Midwest ISO base transmission rate applies to service involving load outside of the Midwest ISO. The service to load within the Midwest ISO is priced at a single rate based on the cost of transmission service in the service area where the load is located. The rate for Midwest ISO transmission to load outside of the Midwest ISO will be an average rate. This rate structure is commonly referred to as a "zonal" or "license plate" approach which seeks to mitigate the effects of any potential cost-shifting during the six-year transition period.

Q. Please explain why a zonal approach mitigates the effects of any potential cost-shifting?

A. One of the most difficult and contentious issues faced by the Midwest ISO participants was pricing. The participants devoted over 18 months to developing a compromise pricing proposal. This compromise was intended to keep as many entities committed to the Midwest ISO as possible. This was difficult because the entities involved were split on pricing with some wanting single-system ISO rates as soon as possible, while others wanted rates based on multiple zones to remain in place indefinitely. In response to these seemingly irreconcilable differences (very similar to those that split the PJM power pool and others), the participants were able to reach a compromise. This compromise approach of zonal rates during a transition period leading to a single-system rate was consistent with FERC's directive in *Atlantic City Electric Co., 77 FERC ¶ 61,148, at 61,577 (1996) ("PJM-I").* The primary concern of the transmission owners was to limit the amount of cost shifting among customers in different service territories by establishing separate zones reflecting the boundaries of existing transmission owners. The transmission owners recognized that, without some protection against cost shifting, utilities would be reluctant to join the Midwest ISO. Therefore, some initial assurances against cost shifting are necessary to ensure broad participation in an ISO. The zonal approach was the only proposal where there was sufficient consensus among the owners as one acceptable way to mitigate cost shifts. The owners decided a six-year transition period would be practical. At the end of the six-year transition period, the progression to a single system base transmission rate will depend upon the pace of retail access.

Q. How is a single grid-wide rate calculated and applied?

A. The sum of the revenue requirements of all the Midwest ISO's participants is divided by the average of their twelve monthly coincident peaks to derive an average single, system-wide rate that will be used for transmission through and out of the Midwest ISO.

Q. Please explain formula rates?

A. The rates for each zone area within the Midwest ISO are calculated annually based on a formula rate filed with the FERC based on the booked transmission facilities, operations and maintenance costs, taxes and other pertinent data found in the FERC Form 1 or other similar filings for non-FERC jurisdictional entities participating. This formula rate is Attachment O in the Midwest ISO open-access transmission tariff and the rates will be recalculated on an annual basis. The FERC has accepted formula rates in other ISO filings.

Q. You previously referred to the Midwest ISO's pricing after the six-year transition period. Please explain how that pricing will operate.

A. At the end of the six-year transition period, a single system base transmission rate will be implemented if all states have implemented retail access, if the participating transmission owners are assured of recovery of costs, or if the participating transmission owners agree, except for those areas covered by a participating ITC, which would implement its own rate structure, subject to FERC approval. If most, but not all, states have retail choice, then the number of zones in the Midwest ISO likely would be reduced. At the end of the transition period, it is envisioned that the majority of states comprising the Midwest ISO will have enacted customer choice legislation and allow for recovery of the appropriate transmission charges from all customers taking service from the Midwest ISO so there should at least be a reduction in the number of rate zones.

(4) Improvement in Service Reliability

Q. What did FERC Order No. 888's guiding principles provide with respect to reliability and system security?

A. Service reliability was one of the three main standards FERC used to judge the Midwest ISO. In principle four of Order 888, FERC noted that an ISO should have the primary responsibility for assuring short-term reliability of the grid.

Q. How will the Midwest ISO improve reliability?

A. The Midwest ISO will establish the necessary infrastructure to maintain transmission reliability. The Midwest ISO will maintain its own security center to monitor transmission reliability and to order actions necessary to maintain reliability. While participating transmission owners will maintain their individual generation control areas, the Midwest ISO will have primary responsibility for ensuring that the regional transmission system is operated reliably.

Q. Will the Midwest ISO act as the Security Coordinator for the transmission systems under its functional control?

A. Yes, the Midwest ISO will be a security coordinator which will enhance reliability. The Midwest ISO also will comply with applicable regional reliability standards issued by NERC or its successor organization.

Q. Will the Midwest ISO coordinate planned maintenance of transmission and generation facilities?

A. Yes, the Midwest ISO will oversee maintenance of transmission facilities and will coordinate maintenance of generation facilities that affect transmission.

Q. Will the Midwest ISO have authority to curtail transactions when system security is jeopardized?

A. The Midwest ISO will control curtailments relating to the regional transmission system. The rules for curtailment are set out in the Midwest ISO Tariff, Sections 13.6, 14.7 and 33. In addition, the Midwest ISO will comply with the applicable NERC and regional council line loading relief procedures. The participating transmission owners will turn over control of their transmission facilities after they have been assured that the Midwest ISO is ready to take over control such that reliable system operations will be maintained.

Q. How will the Midwest ISO manage congestion?

A. The Midwest ISO will be able to identify constraints on the operating system and relieve such constraints by taking necessary actions. In reviewing the application for approval of the Midwest ISO, FERC approved the Midwest ISO's procedures for attaining service reliability. Under the Tariff, the Midwest ISO has an obligation to identify transmission constraints. In some circumstances, the Midwest ISO will arrange for the re-dispatch of generating units to relieve constraints. The Midwest ISO will have the ability to require re-dispatch in order to deal with emergency circumstances. In other circumstances, where a customer can receive new service only if re-dispatch occurs, the Midwest ISO will identify the constraint and the generators that can relieve the constraint for the customer.

Q. Please explain how the congestion relief mechanism operates.

A. The Midwest ISO filing contains a straightforward approach for congestion relief and creates two separate categories of congestion relief. The first category involves costs incurred to prevent already committed Midwest ISO firm transmission (or network service) from being curtailed. This category proposes to spread these costs among all load as this re-dispatch will address system problems. These costs are therefore more properly spread and allocated to all load rather than being directly assigned. This approach also allows Midwest ISO system operators to act quickly to remedy system problems without having to worry about the Midwest ISO being able to recover the costs.

The second category involves entities seeking firm transmission service who are told that firm service can be provided only if capacity is reassigned or some form of re-dispatch occurs. The Midwest ISO will facilitate congestion relief in this case, but it will not actually execute contracts or provide the service. The goal here is to provide the customer with numerous options and to allow the customer to choose. The Midwest ISO will therefore help to facilitate the re-dispatch of generating units and the assignment of capacity by firm point-to-point customers and provide information on re-dispatch options. This facilitation of the assignment of unused transmission facilities is consistent with the FERC's direction in *PJM II*, that an ISO allow tradable transmission rights. Further, because the Midwest ISO will not own or control generators, it makes sense for the Midwest ISO to act as the facilitator and not as the supplier of re-dispatch services.

Q. To what extent will the Midwest ISO be the supplier of last resort for the ancillary services necessary for reliable operation of the transmission grid?

A. The Midwest ISO will not own any generation facilities; therefore, it will not supply ancillary services itself. The Midwest ISO will be the supplier of last resort and will procure, on a contractual basis, those ancillary services necessary for reliable operation of the transmission grid. The Midwest ISO will take all reasonable steps to insure that all necessary ancillary services that are self-provided by transmission customers are obtained from generation suppliers that have adequate generation resources.

Q. Will the Midwest ISO have any mechanism to address parallel path/loop flow loading of critical transmission facilities within the region?

A. Yes. The Midwest ISO will have real-time data for the entire regional transmission system under its control, including all critical interfaces and flowgates, in order to assure system security and maintain reliability over a large regional transmission system.

Q. To what extent will the Midwest ISO be responsible for the expansion and planning functions for transmission facilities under its control?

A. The participating transmission owners will continue to be responsible for planning their local transmission system expansion, upgrades and reinforcements. These local plans will be presented to the Midwest ISO on a regular basis for purposes of approval and coordination among plans over the Midwest ISO region. This is commonly referred to as a "bottoms-up, top-down approach." The Midwest ISO will conduct and coordinate planning, including load flow studies, on a regional basis. This is the "top down" portion of transmission planning, where the Midwest ISO will develop regional transmission plans.

(5) Open Competition

Q. How does the Midwest ISO help promote competition?

A. FERC used open competition as one of three basic standards to approve the Midwest ISO. The Midwest ISO's transmission usage and availability will be publicly available on OASIS on a real-time basis. The Midwest ISO's transmission rates will be publicly available on its OASIS and the tariff rates will be calculated in a uniform manner for all Midwest ISO participating transmission owners. This will enable users to make informed decisions on the availability and cost of transmission services.

Q. How does the pricing approach enable open competition?

A. Under the zonal pricing approach, certain special rules were adopted in order to ensure comparability and to make the approach more palatable to a broader range of entities. For example, the pricing approach seeks to charge all customers the same price when those customers seek to serve the same load. This concept of putting all competitors on an even playing field is one of the underlying principles of comparability in FERC Order No. 888. Further, as part of the transition period, customers or loads are considered as being under the tariff once those customers or loads have the option of choosing different suppliers. Whether the customer chooses a new supplier or not, the same transmission rate will apply. If retail customers have choice but choose to continue to purchase power from the transmission owner, the transmission owner must take service from the Midwest ISO for those customers. After the transition period, all load (including load under grandfathered agreements) will be under the Midwest ISO. If transmission owners serve bundled customers at this time, whether the customers have choice or not, the transmission owners will be required to take service for that load from the Midwest ISO.

Q. Why does the elimination of rate pancaking enhance competition?

A. The elimination of rate pancaking as provided under the Midwest ISO's pricing model will provide very substantial benefits to all market participants and bundled retail and wholesale customers in the Midwest. There should be an overall reduction in the costs of transmitting energy in the region with the elimination of pancaking. The elimination of rate pancaking puts all generators on an equal footing to serve the same load. This provides generation sources with equal transmission access. Due to these lower rates, one stop shopping (i.e., going to one transmission provider instead of many), the establishment of uniform and clear rules, the separation of control over transmission from marketing, regional planning of transmission, and enhanced reliability, all market participants will benefit greatly from the Midwest ISO. The marketplace clearly will become more competitive. Sellers will have access to more markets for their products. Buyers, on the other hand, will have greater access to sources of supply.

Q. **Does the Midwest ISO provide any preferential treatment to participating transmission owners who are part of a vertically integrated utility that owns generation resources?**

A. No. Great pains were taken to ensure that participating transmission owners, to the extent they are involved in power sales, are treated the same as everyone else under the tariff, and they are. Participating transmission owners use the tariff only as eligible customers. Other changes were made to ensure that participating transmission owners take and pay for the same service as other competitors would to serve the same load, as provided in Sections 13.3 and 14.3, and Part IV of the tariff. The tariff therefore creates a level playing field.

Q. **How many OASIS sites will the Midwest ISO operate for the transmission facilities under its control?**

A. The Midwest ISO will operate a single OASIS site for the transmission facilities under its control. Information concerning the Midwest ISO's transmission usage and availability will be publicly available on the OASIS on a real-time basis. The Midwest ISO's transmission rates will be publicly available in its tariff and the tariff rates will be calculated in a uniform manner for all participating transmission owners within the Midwest ISO. This will enable transmission users to make informed decisions on the availability and cost of transmission services.

Q. What entities will be responsible for processing requests for transmission service within the Midwest ISO?

A. The Midwest ISO will be responsible for processing requests for transmission service within the Midwest ISO. The Midwest ISO will also be responsible for tariff administration, including all transmission service reservations and scheduling as set forth under the provisions of the Midwest ISO's Open Access and Transmission Tariff.

Q. How many different transmission entities will transmission customers need to contact in order to obtain transmission services within the Midwest ISO?

A. The Midwest ISO will provide transmission customers with a one-stop shop for all necessary transmission services, including the provision of ancillary services. Under Appendix I, transmission service within an ITC could potentially be requested directly to the ITC and coordinated with the Midwest ISO. Transmission customers also have the option to procure ancillary services on their own.

Q. Who will be responsible for calculating ATC within the Midwest ISO?

A. The Midwest ISO is ultimately responsible for calculating ATC and the determination of equipment ratings within the Midwest ISO. The participating transmission owners will provide some information and the necessary equipment ratings, subject to the Midwest ISO's review and acceptance and the dispute resolution process. The only exceptions may involve ITCs pursuant to the Appendix I procedures, subject to FERC approval. The ITCs may provide the equipment ratings and assumptions to the Midwest ISO subject to dispute resolution if the Midwest ISO disagrees.

Q. Does the Midwest ISO have any type of alternative dispute resolution procedure?

A. Yes. The Midwest ISO has an alternative dispute resolution procedure capable of resolving conflicts, on an expedited basis, regarding the use and control of the transmission facilities. Pursuant to the FERC order, the Midwest ISO will revise these procedures in the future.

Q. How does the Midwest ISO's alternative dispute resolution procedure operate where there is a dispute regarding the Midwest ISO's determination of ATC and Capacity Benefits Margin (CBM)?

A. The Midwest ISO's alternative dispute resolution procedure provides that where there is a dispute regarding the Midwest ISO's determination of ATC and CBM, the Midwest ISO's determination will prevail pending the outcome of the alternative dispute resolution procedure. The FERC has required that the Midwest ISO develop expedited dispute resolution procedures to handle disagreements on ATC issues.

(6) Adequate Size and Scope

Q. Is the Midwest ISO of adequate size and scope?

A. The Midwest ISO as it is currently comprised is of adequate size and scope.

When FERC initially conditionally approved the Midwest ISO, it was deemed as having adequate size and scope to be viable. Since that time it has grown to an even larger regional interconnected electrical transmission system covering portions of sixteen states, 305,000 square miles of service territory, 91,000 megawatts of regional generation, 69,000 miles of transmission circuits and $8.5 billion dollars of transmission facilities. The Midwest ISO remains the largest of all approved or proposed ISOs in the United States. In my opinion, the Midwest ISO or another regional ISO should, however, include all of the major transmission systems within the ECAR and MAIN regions, at a minimum, in order to realize the maximum reliability benefits of the Midwest ISO.

Q. Did the Public Utilities Commission of Ohio intervene in the Midwest ISO proceeding at the FERC?

A. Yes. The Public Utilities Commission of Ohio (PUCO) filed comments in response to the Midwest ISO case at FERC. The PUCO's comments specifically asked FERC to review whether the Midwest ISO was of adequate size and scope. FERC acknowledged that principle three of Order 888 requires an ISO's transmission grid to be as large as possible. According to FERC, the greater the size of an ISO, the better able it is to promote competition and system reliability. FERC concluded that the Midwest ISO was of adequate size and scope at the time the ISO participants filed for FERC approval on January 15, 1998. Since that time, additional owners of transmission facilities have joined the Midwest ISO, so it has even greater size and scope, with 15 transmission owners in portions of 16 states, including 91,000 megawatts of installed generating capacity and $8.5 billion dollars in gross transmission investment.

Q. Do you have an opinion as to whether the Midwest ISO is of adequate size and configuration?

A. Yes.

Q. What is your opinion?

A. In my opinion, the Midwest ISO, as currently constituted, certainly has adequate size and scope to be viable. However, I believe that a larger Midwest ISO would enhance system reliability.

Q. Has the Midwest ISO performed a Herfindahl-Hirschman Index (HHI) or related measurement to determine whether the relative geographic market for generation supply is highly concentrated?

A. No. The Midwest ISO should not be burdened with this responsibility. The Midwest ISO will own no generation assets. The Midwest ISO will not perform any regulatory function in assessing how concentrated the geographic market for generation supply is.

Q. To what extent does the Midwest ISO have mechanisms or procedures in place to mitigate excessive market power?

A. The fact that the Midwest ISO is of sufficient size and configuration mitigates potential market power abuses which may otherwise exist if a party tried to leverage the use of its transmission system to favor its affiliated generation.

(7) Independent Governance

Q. Please describe the Midwest ISO's governance structure.

A. The Midwest ISO's governing structure consists of an independent Board of Directors and an advisory committee. All eligible customers for transmission service (generally defined as electric utilities, power marketers, federal power marketing agencies and persons generating electricity for re-sale) may become members of the Midwest ISO. The members assist in the development of operating procedures and emergency procedures of the Midwest ISO. The members also elect the Board of Directors, consisting of seven directors and a president. The directors and president may not have served, within two years prior to or subsequent to office, as either a director, officer or employee of any Midwest ISO member, user or their affiliates.

The FERC found that this governing structure produces an independent Board, which should not favor any single market participant or any industry class. The Board of Directors hires and may fire the president. The Board may amend and may repeal the Midwest ISO's rules. The Board sets general policy and oversees the president's implementation of these policies. The president implements the Board's policies by controlling the day-to-day operation of the Midwest ISO. The Board's ability to amend the Midwest ISO agreement is limited in areas such as compliance with regulatory and reliability requirements, revenue distribution and the pricing approach.

Q. To what extent are the Midwest ISO's directors and employees permitted to have a financial interest in the Midwest ISO participants?

A. The directors and Midwest ISO employees are barred from having any financial interest in the Midwest ISO participants and must follow a code of conduct that prohibits them from favoring or discriminating against any Midwest ISO participant.

Q. To what extent is the Midwest ISO's decision-making process independent of control by market participants or classes of participants?

A. The Midwest ISO participants have adopted a disinterested Board structure. The Board structure was adopted largely due to requests by the state regulators that such a structure be adopted. The framework of the Board is modeled on the structure of the board of directors the FERC found acceptable in *PJM-II* and *New England Power Pool, 83 FERC 61,045 (1998)*. *In New England Power Pool,* FERC stated that "a board of directors with no affiliation with any entity dealing with the ISO would assure fair and non-discriminatory governance". *Id.* at 62,585. Consistent with *New England Power Pool,* the structure of the Midwest ISO Board is designed to ensure that it is "comprised of qualified, non-partial members." The Midwest ISO is structured in a manner that ensures independence. The Midwest ISO Board will control all Midwest ISO decisions and operations and can modify the governing agreements including the appendices (subject, of course, to filings with the FERC) with a few very limited exceptions. The principal exception involves pricing and revenue distribution, which may be changed only with the consent of the transmission owners. The pricing and revenue distribution compromises are the heart of the Midwest ISO filing and were the items where the compromise reached by the transmission owners is most fragile. The participants spent many months negotiating these items and have relied upon their agreement on such matters in executing the agreement. The participants simply cannot have these items subject to change by the Midwest ISO Board beginning on the first day the Board is put in place.

Q. Does the Board of the Midwest ISO operate independently?

A. Yes. The governance structure ensures that the Midwest ISO will be independent of any individual market participant or any one class of participants. The Board candidates for the Midwest ISO were selected by the members, including those transmission owners that joined as members, from a slate of fourteen candidates presented by the executive search firm, Hedrick & Struggles. Hedrick & Struggles recruited these candidates independent of the membership based on the criteria that no Board candidate will have any affiliation with any entity dealing with the Midwest ISO. Hedrick & Struggles had prior experience in searching for ISO Board candidates. Members elected the Midwest ISO Board members from the slate of candidates with each transmission owning member receiving one vote for each director slot just like any member. The Board therefore is completely independent and