Comments on EPA's Proposed Clean Water Act Section 316(b) Regulations for Cooling Water Intake Structures at Phase II Existing Facilities

Proposed Rule, RIN 2040-AD62

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1. Introduction

Riverkeeper, Inc. retained Synapse Energy Economics, Inc. ("Synapse") to assist in the preparation of comments concerning EPA's Phase II Rule on Cooling Water Intake Structures at large existing electric generating facilities. In particular, Synapse was asked to address the following issues:

1. Whether the EPA's analyses have realistically quantified the likely costs of complying with feasible technology alternatives including capital costs and energy penalties associated with the ongoing operation of new recirculating cooling water systems and the one-time outage during which such new systems would be connected to a plant's existing cooling water system.
2. Whether the EPA's economic analyses and use of the IPM model realistically quantify the price and reliability effects on the electric grid of complying with the proposed rule and/or other reasonable regulatory options.
3. Whether the EPA has appropriately considered the potential for the repowering of existing facilities as part of complying with the proposed rule and/or other reasonable regulatory options.

This report presents the results of Synapse's evaluation of these issues.

2. Summary of Findings

Synapse has found that:

1. We were not able to gain access to critical analyses and data needed to evaluate the proposed Phase II Existing Facilities Rule ("Phase II Rule) and the alternative regulatory options because this information has been designated as Confidential Business Information.
2. There would be no adverse impact on electric system reliability from the implementation of the proposed Phase II Rule, the All Cooling Tower Option (Federal Register Option 1) or the Waterbody/Capacity-Based Option (Federal Register Option 3).
3. The EPA analyses over-estimate the amount of capacity that would be retired under the All Cooling Towers and Waterbody/Capacity-Based Options.
4. The costs of complying with the alternative regulatory options that would require cooling towers would be minor in the context of overall electricity costs to consumers.
5. The EPA's predicted costs of complying with the alternative regulatory options are significantly overstated.
6. There appears to be a contradiction between the definitions of "repowering" in EPA's Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule ("EBA") and the Technical Development Document and the Federal Register Notice.

7. The EPA appears to have failed to consider the potential for the repowering of older, coal-fired facilities to use combined cycle technology.

8. The cost-to-revenue analyses presented in the EBA appear to overstate the magnitude of compliance costs relative to facility-level and firm-level revenues.

3. Data Availability

We were not able to gain access to critical analyses and data needed to evaluate the proposed Phase II Rule and the alternative regulatory options because this information has been designated as "Confidential Business Information" ("CBI"). In particular, it is impossible to identify, let alone assess the reasonableness of, the individual facility and firm level costs and reliability impacts of the proposed rule and the alternative options because (1) we cannot determine which individual facilities and firms would be affected by the alternative regulatory options and (2) there is insufficient non-CBI information to allow any detailed plant or firm-specific assessment of the analyses provided by the EPA. It also is impossible to assess how realistically the IPM models the effect of the various regulatory options because so much of the underlying information has been designated CBI.

4. Reliability Impacts

Finding: There would be no adverse impact on electric system reliability from the implementation of the proposed Phase II Rule, the All Cooling Tower Option (Federal Register Option 1) or the Waterbody/Capacity-Based Option (Federal Register Option 3).

The installation of the Impingement and/or Entrainment ("I&E") controls that would be required under the proposed Phase II Rule would have no energy penalty or any effect on facility reliability and availability. Affected facilities would not have any incremental outage time to install these measures because they can be installed while the plant is in operation or during normally scheduled maintenance downtime. Thus, electric system reliability would not be affected by the installation of I&E controls at affected facilities.

Consequently, only the regulatory options requiring the installation of Flow Reduction Technologies could potentially have any impacts on electric system reliability. However, as explained below, even these more aggressive options would only have negligible impacts on system reliability.

As shown in Table B8-1 in the EBA, under the Waterbody/Capacity-Based Option a total of 52 facilities, representing 5.9 percent of National Pre-Run Capacity, would have to add cooling towers. However, EPA has assumed that the new cooling towers could be built while an affected facility is operating and that the attachment of the new tower to the existing cooling system would have only a one-time effect, extending a planned maintenance outage by one month. Therefore, if the transition took place over five years and the extra month of downtime occurred randomly throughout the year, the total 5.9 percent affected capacity actually would become an average reduction in national generating capacity at any one time of only 0.1 percent.[1] Such a minor reduction in available capacity would have no effect on the reliability of the national electric system during the five-year transition period, especially considering the 26-percent summer 2005 and the 53-percent winter 2005/2006 reserve margins projected by NERC.[2]

Moreover, the cooling system conversions would undoubtedly be scheduled to occur preferentially during the off-peak seasons when system loads are lower and capacity reserves and reserve margins are much higher. Therefore, the implementation of this option would have even less of an effect on electric system reliability than even these minor impacts would suggest.

The same would be true for the individual regional NERC electric systems. For example, Table B8-1 reveals that, when considered on a regional basis, the maximum fraction of generating capacity that would be affected by the Waterbody/Capacity-Based Option would be 16.7 percent in both the FRCC and the NPCC NERC regions. However, if the transition were planned to take place over five years with the extra month of downtime spread throughout the year, this 16.7 percent of affected capacity would become an average reduction of only 0.3 percent in the amount of capacity available in each of these regions.[3] Again, this extremely minor decrease in the amount of generating capacity that would be available during the five-year transition period would not have any adverse effect on electric system reliability in the FRCC and NPCC NERC regions given the 23.1 percent (FRCC) and 28.2 percent (NPCC) reserve margins forecast for these regions for the summer of 2005.[4] The proposed Waterbody/Capacity Based Option would have even less of an effect on electric system reliability in the other NERC Regions where EPA estimates that significantly less generating capacity would be affected.[5]

The implementation of the Dry Cooling Option (EBA Option 5) would have similarly minor impacts on the amounts of electric generating capacity that would be available at any one time during the five year transition period and, therefore, also would not have an adverse effect on electric system reliability.

Under the All Cooling Towers Option, 416 facilities representing 33.1 percent of National generating capacity would have to add cooling towers. But the facility outages required to connect these new cooling towers also could be scheduled to occur throughout the five-year transition period. As a result, on average, only 0.5 percent of the nation's electric generating capacity would be out of service at any one time as a result of

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1 This 0.1 percent figure represents the total 5.9 percent of national capacity that EPA estimates would be affected by the option divided by the 60 months in the five-year transition period.

2 *Reliability Assessment, 2001-2010, The Reliability of Bulk Electric Systems in North America*, North American Electric Reliability Council, October 16, 2001, Table 1, at pages 14 and 15.

3 This 0.3 percent figure represents the total 16.7 percent of the FRCC and NPCC regional generating capacity that EPA estimates would be affected by the option divided by the 60 months in the five-year transition period.

4 *Reliability Assessment, 2001-2010, The Reliability of Bulk Electric Systems in North America*, North American Electric Reliability Council, October 16, 2001, Table 1, at pages 14 and 15.

5 See Table B8-1 on page B8-2 of the EBA.

the implementation of this regulatory alternative.[6] As noted above, such a minor reduction in available capacity would have no effect on the reliability of the national electric system during the five-year transition period considering the 26-percent summer 2005 and the 53-percent winter 2005/2006 reserve margins projected by NERC.[7]

At the same time, only 0.75 percent of the generating capacity in the ECAR and NPCC regions, on average, would be out of service at any one time.[8] An even smaller percentage of the generating capacity would be out of service at any one time, on average, in the other NERC regions as a result of the implementation of the All Cooling Towers Option.

As noted above, this assumes that the extra downtime needed to connect the new cooling towers would be spread evenly throughout the year. It is far more likely that the extra downtime would be preferentially scheduled to occur during the off-peak seasons when system loads are lower and capacity reserves and reserve margins are significantly higher. As a result, the implementation of the All Cooling Towers Option would have even less of an effect on national and regional electric system reliability than these figures would suggest.

The EPA also assumes that there would be continuing energy penalties from the conversion to recirculating systems with wet or dry cooling towers.[9] However, the reductions in net plant capacity from such conversions would have a negligible effect on electric system reliability, as shown by the EPA itself. For example, Table B8-3 in the EBA reveals that implementation of the Waterbody/Capacity-Based Option would reduce the total national domestic generating capacity in 2013 by about 800 MW which would be only a 0.1 percent reduction from EPA's estimated 922,740 MW. The same Table reveals that implementation of the All Cooling Towers Option would reduce the total national domestic generating capacity in 2013 by only 3,380 MW, or only 0.4 percent. Clearly, such minor reductions would not have a significant impact on electric system reliability.

However, there are a number of reasons why even these extremely minor reductions in available capacity overstate the effect that the implementation of either the All Cooling Towers or the Waterbody/Capacity-Based Options would have on electric system reliability.

First, the EPA analyses significantly understate the amount of generating capacity that should be available during and after the five-year transition period. For example, EPA

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6 This 0.5 percent figure represents the total 33.1 percent of national capacity that EPA estimates would be affected by the option divided by the 60 months in the five-year transition period.

7 *Reliability Assessment, 2001-2010, The Reliability of Bulk Electric Systems in North America*, North American Electric Reliability Council, October 16, 2001, Table 1, at pages 14 and 15.

8 This 0.75 percent figure represents the approximately 44 percent of regional ECAR and NPCC generating capacity that EPA estimates would be affected by the option divided by the 60 months in the five-year transition period.

9 EBA, at Table B1-1.

assumes that there would be 941,990 MW of national generating capacity in 2008.[10] This is more than 200,000 MW less than the 1,045,335 MW of generating capacity forecast by the individual NERC regions and approximately 178,000 MW less than NERC's Reliability Assessment Subcommittee believes to be the "most likely scenario going forward."[11]

The EPA then appears to make the extremely unrealistic and unreasonable assumption that the amount of national generating capacity actually will decrease from 941,990 MW in 2008 to 922,740 MW in 2013.[12] Such an assumption is entirely unwarranted and unrealistic in light of the tremendous growth in electric generating capacity projected for the period 2001 through 2010. For example, the NERC assumes that approximately 134,000 MW of new capacity will be added nationally by 2010.[13] There is no basis to expect that this growth will end and that the amount of generating capacity actually will decrease after 2010.

Second, the EPA analyses ignore the additional capacity that would be available from the repowering of coal-fired facilities. Instead, the EPA defines repowering a facility as the change from oil/gas capacity to combined-cycle capacity. By doing so, it excludes any consideration that an affected coal-fired facility could be repowered to combined-cycle capacity. As discussed in more detail later in these comments, a literature review reveals that at least 16 coal-fired facilities have been or are planning to be repowered. The repowering of these and other coal-fired plants will add thousands of additional megawatts of generating capacity to the national electric system and, thereby, improve system reliability while reducing water usage.

Third, the EPA analyses ignore the additional capacity that will be available from the implementation of power uprates at nuclear power plants. A power uprate means increasing the thermal power produced by the plant. A power uprate increases the output of the plant at a relatively low cost. The U.S. Nuclear Regulatory Commission has approved more than 60 such power uprates of between 5 and 20 percent. Requests for additional uprates are currently under review by the NRC or are planned for submission in the near future. An average increase of 10 percent in the power levels of the nation's nuclear plants would add approximately 9,000 megawatts of additional capacity to the electric system.

Fourth, it appears that EPA has assumed that the service lives of some, but not all, nuclear power plants, will be extended beyond the current 40 year terms of their Nuclear Regulatory Commission-issued operating licenses.[14] However, it is impossible to tell how many nuclear units, and which individual facilities, are assumed to have their

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10 EBA, at Table B8-1.

11 *Reliability Assessment, 2001-2010, The Reliability of Bulk Electric Systems in North America*, North American Electric Reliability Council, October 16, 2001, at pages 11 and 17.

12 See Tables B8-1 and B8-2 in the EBA.

13 *Reliability Assessment, 2001-2010, The Reliability of Bulk Electric Systems in North America*, North American Electric Reliability Council, October 16, 2001, at page 17.

14 EBA, at page B3-9.

operating lives extended Given the NRC's recent actions and stated intentions, it is reasonable to expect that the NRC will allow any owner that wants to extend the operating life of its nuclear plant to do so. Therefore, there may be more generating capacity available over the next 30 to 50 years than has been assumed in the EPA analyses.

Fifth, the EPA analyses reflect the costs of condenser upgrades[15] but not the improved performance (in terms of fewer tube failures and lower forced outage rates) that can be expected from such upgrades. In other words, the facilities which have implemented condenser upgrades should be available for service for more of the year than they previously had been. This additional capacity can be expected to further enhance electric system reliability.

Finally, the EPA analyses assume that some generating capacity will be retired as a result of the implementation of the All Cooling Towers and Waterbody/Capacity-Based Options.[16] As explained below, we believe that the assumption that significant nuclear capacity would be retired as a result of the proposed All Cooling Towers or Waterbody/Capacity-Based Options is unreasonable and unrealistic. The availability of this nuclear capacity that EPA assumes would be retired would further reduce system reliability impacts.

In any event, the retirement of some of the facilities that would have to add cooling towers might spur the construction of additional new combined-cycle plants that would use less water.

5. Capacity Retirements

Finding : The EPA Analyses over-estimate the amount of capacity that would be retired under the All Cooling Towers and Waterbody/Capacity-Based Options.

The EPA notes that 2,550 MW of nuclear capacity in the NPCC and WSCC would be retired as a result of the adoption of the Waterbody/Capacity-Based Option.[17] The EPA does not identify the number of MW of nuclear capacity that would be retired as a result of the adoption of the All Cooling Towers Option. However, it is reasonable to expect that the same nuclear facilities that EPA predicts would close in its analysis of the Waterbody/Capacity-Based Option also would be predicted to close in EPA’s analysis of the All Cooling Towers Option.

Unfortunately, the analyses and underlying data which form the basis for the EPA conclusion that this nuclear capacity would be retired as a result of these options has been designated CBI. Therefore, we have been unable to evaluate, let alone validate, these

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15 See the Phase II Technical Development Document at pages 2.18 and 2.26.

16 EBA, at page B8-3.

17 EBA, at page B8-3.

results.[18] Moreover, based on previous Synapse work, we believe that it is extremely unrealistic to expect that currently operating nuclear power plants will be retired as a result of the adoption of any of the flow reduction technology based regulatory options. This conclusion is based on (a) the improved performance and reduced O&M costs achieved at nuclear plants since the mid-1990s, (b) the fact that nuclear plants' low operating and fuel costs allow them to compete successfully in bid-based wholesale markets, and (c) the significant economic benefits that are available from relatively low cost investments in plant power uprates and operating life extensions.

For example, a recent Synapse analysis concluded that a $36 million investment in increasing the power level of the Vermont Yankee Nuclear Plant by 13 percent would result in a net present value benefit of $56 million (in 2001 dollars).[19] A similar investment in extending the unit's operating life by twenty years would produce a net present value benefit of $253 million.[20] With the opportunity for potential economic benefits of this magnitude, it is unlikely that any nuclear plant would be retired as result of the adoption of the cooling tower options considered by the EPA.

In addition, the EPA analyses ignore the possibility that fossil-fired facilities will be repowered instead of retired as a result of the adoption of any of the flow reduction technologies. The examples of the Reliant Astoria Repowering Project and the Bethlehem Energy Center in New York State are evidence that firms will seek to repower older, less efficient generating facilities and that such repowerings can include cooling towers as part of the repowered facility in place of once-through cooling. Such projects will provide significant environmental benefits in terms of reduced water usage and lowered air emissions and will offer substantial economic benefits for their owners.

6. Cost Estimates

Finding: The Costs of Complying with the alternative regulatory options that require cooling towers would be minor in the context of overall electricity costs to consumers.

As shown in Table 1 below, the compliance costs projected in the EBA would lead to very minor increases in the average cost of generating electricity at the affected facilities. In fact, these cost increases would average only 0.1 cents per kilowatt hour ("kwh") even under the All Cooling Towers Option (EBA Option 4), which would add cooling towers at 416 facilities. The average price of generating electricity at the affected facilities would increase by only 0.026 cents per kwh under the Waterbody/Capacity-Based Option (EBA Option 1).

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[18] We have similarly been unable to evaluate the analyses underlying the EPA claim that some fossil-fired units also would be retired as a result of these options.

[19] Redacted Prefiled Testimony of Bruce E. Biewald in Vermont Public Service Board Docket No. 6545, dated January 7, 2002, at page 31, lines 16-18.

[20] Ibid., at page 32, lines 1-5.

Table 1 – Average Annual Costs per kwh of Alternative Regulatory Options Analyzed by EPA[21]

Options	Annual Costs 2001$	Average Annual Cost of Option: Cents per kwh of output at Phase II Facilities	Average Annual Cost of Option: Cents per kwh of output at all industry facilities
EBA Option 1 - Waterbody/Capacity-Based	$595,300,000	0.026	0.015
EBA Option 2	$378,600,000	0.016	0.009
Proposed Rule	$182,000,000	0.008	0.004
EBA Option 3a	$195,400,000	0.008	0.005
EBA Option 4 - All Cooling Towers	$2,316,400,000	0.101	0.056
EBA Option 5 - Dry Cooling	$1,252,000,000	0.054	0.031

It is not certain that in deregulated markets the owners of affected facilities could pass these cost increases along to their customers. But even if they could, the overall price paid by consumers for the electricity they use would reflect a blend of both the price of generating electricity at affected facilities and the price of generating electricity at non-affected facilities. Consequently, as shown in the last column of Table 1, the average price of electricity paid by consumers would increase by only 0.056 cents per kwh under the All Cooling Towers Option or by 0.015 cents per kwh under the Waterbody/Capacity-Based Option.

These average cost increases are extremely minor when compared to the average 8.47 cents per kilowatt hour paid by residential electricity consumers in 2000.[22] For example, the 0.056 cents per kilowatt hour increase projected for the All Cooling Towers Option would represent only a 0.66 percent increase in an average residential customer bill.[23] The 0.015 cents increase projected for the Waterbody/Capacity-Based Option would represent only a 0.18 percent increase in an average residential bill.[24]

In other words, an average consumer who uses 500 kilowatt hours per month might see his/her bill increase by only 7.5 cents per month if the Waterbody/Capacity-Based Option

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21 The annualized costs for each of the options shown in the middle column of Table 1 were taken from Tables B7-2, B7-7, B7-12 and B7-17 of the EBA. The individual cents per KWH costs shown in the right hand column were calculated by dividing each of these annual costs by the 2,300,000,000 of net generation forecast for affected facilities in Table A2-2 of the EBA.

22 *Typical Electric Bills and Average Rates Report, Winter 2001*, Edison Electric Institute, at page 188.

23 0.056 cents per kilowatt hour divided by 8.47 cents per kilowatt hour equals 0.66 percent.

24 0.015 cents per kilowatt hour divided by 8.47 cents per kilowatt hour equals 0.18 percent.

were adopted.[25] The average consumers' bill could increase by only 28 cents per month if the All Cooling Towers Option were adopted.[26]

Finding: The Costs of Complying with the alternative regulatory options are significantly overstated.

Although the costs of complying with the alternative regulatory options that require the implementation of flow reduction technologies are extremely low, they are nevertheless overstated for the following reasons:

First, the capital costs of adding a cooling tower are annualized over a 30-year period even though the EPA has acknowledged that there is substantial evidence that cooling towers have service lives longer than 30 years. The EPA should annualize the capital costs of adding cooling towers over a period that is more likely to reflect the expected operating lives of those towers. Such an annualization over a period longer than 30 years would lower the annual compliance costs presented in the EBA for the All Cooling Towers, the Waterbody/Capacity-Based and Dry Cooling Options.

Second, the EPA notes that data from the Nuclear Regulatory Commission indicate that "recirculating cooling systems have lower condenser flow to MW ratios than once-through systems, regardless of age or other characteristics."[27] However, the EPA nevertheless uses the baseline (i.e., once-through) system intake flow of affected plants to size the needed recirculating cooling towers and associated conduit systems.[28] This assumption renders the affected facility recirculating systems modeled by EPA oversized and unnecessarily expensive. EPA instead should have used the Nuclear Regulatory Commission data to properly size the cooling system conversions.

Third, to calculate the capital costs of wet cooling towers, the EPA starts with the cost of a redwood tower with splash fill for all fossil-fuel plants. Such a cooling tower is slightly more expensive than a tower fabricated from fiberglass reinforced plastic.[29] Further, EPA has acknowledged that it has learned from cooling tower vendors that fiberglass has become "relatively standard" for new facility installations.[30] EPA should have used the cost of the more standard fiberglass material for new cooling towers at existing fossil-fired facilities.

Fourth, the equations used by EPA to quantify the capital cost of a new cooling tower produce cost estimates that "in almost all cases" exceeded the actual project costs,

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[25] This 7.5 cents per month increase represents the 0.015 cents per KWH increase shown for this option in Table 2 multiplied by an average 500 KWH per month usage.

[26] This 28 cents per month increase represents the 0.056 cents per KWH increase shown for this option in Table 2 multiplied by an average 500 KWH per month usage.

[27] Technical Development Document, at page 2.18.

[28] In fact, EPA notes that in some cases, the design flows it used are significantly higher than actual operating flows. Technical Development Document, at page 2.18.

[29] Technical Development Document, at page 2.22.

[30] Ibid.

sometimes by as much as 25 percent of the actual costs.[31] For this reason, EPA should revise its equations to more accurately reflect the actual costs of building a cooling tower. In the alternative, if the EPA decides to continue to use these equations without revision, it should not apply a 20 percent "retrofit factor" when quantifying the cost of adding a cooling tower at an existing facility. The combined use of both the existing equations and the 20 percent retrofit factor leads to unreasonably high estimates for the capital costs of adding a new cooling tower at an existing facility.

Fifth, the EPA assumed that in order to increase the efficiency of the recirculating cooling system affected facilities would elect to upgrade their condensers as part of cooling system conversions from once-through to recirculating systems.[32] Although the costs of these condenser upgrades were included in the EPA's quantification of compliance costs, these costs do not reflect any reductions in condenser-related O&M costs that can be expected from upgrading to the new materials which are less susceptible to failure. Such material upgrades should lead to fewer tube leaks and, consequently, lower repair and repair outage-related costs.

Sixth, the EPA assumed that a range of 2,000 feet to 4,000 feet (depending on intake flow) of concrete-lined steel piping would be used for cooling water make-up water and blowdown.[33] The EPA included these costs to account for conversion cases in which significant distances may exist between intake locations and cooling tower sites even though this was not necessarily true for the example cases reviewed by EPA. EPA should have used a range of piping length that is more typical of existing facilities instead of using a range that might only apply to a limited number of plants.

Seventh, the only intake structure technologies for which EPA develops costs are fine mesh traveling screens and fish handling equipment. The EPA notes that "fine mesh traveling screens tend to have higher costs, in the Agency's estimation than other similar technologies."[34] The EPA should identify these other viable intake structure compliance strategies, and compliance cost estimates should reflect the use of these strategies at facilities can be expected to use them.

Eighth, the EPA notes that it does not develop costs for certain compliance strategies that companies may employ in response to the new rule.[35] Several of these compliance strategies are likely to be less costly than the strategies for which the EPA has developed costs. The EPA should cost out all applicable compliance strategies in order to develop an accurate assessment of each option's costs.

Ninth, as noted earlier, the EPA analyses do not reflect the repowering of coal-fired facilities to use combined-cycle technology. However, as we will discuss below, at least 16 coal-fired facilities have been repowered or are planning to so repower in the near

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[31] Technical Development Document, at page 2.23.

[32] Technical Development Document, at pages 2.18 and 2.26.

[33] EBA, at page B1-4.

[34] Technical Development Document, at page 2.16.

[35] EBA, at page B1-17.

future. The costs of compliance under the All Cooling Towers, the Waterbody/Capacity-Based and Dry Cooling Options are overstated to the extent that they fail to reflect these repowerings because the costs of complying with any of these options would be lower for a repowered facility than for the original coal-fired plant.

Tenth, the energy penalties used by the EPA to develop the compliance costs are too high, as follows:

1. To calculate the cost of foregone electricity sales during the extended outage to connect a wet tower to an existing plant, EPA uses annual average electricity sales figures for the company and annual average wholesale prices. As the Agency notes, these outages are likely to occur during the off-peak seasons (spring and fall), when both electricity sales and wholesale prices are below annual average levels.[36] Thus, the use of annual average data will tend to overstate the cost of the extended outage. We believe that EPA should use electricity sales and wholesale price data from off-peak seasons to calculate this cost.

   The EPA only quantified the avoided fuel costs from this one-month downtime. However, EPA also has noted that variable production costs other than fuel costs may be avoided during downtime. By only including fuel costs and ignoring the avoided variable production costs, EPA may have overstated the cost of the connection outage.[37]

2. In calculating the energy penalty associated with reduced steam turbine efficiency, EPA calculates energy losses at 67-percent load operation for all in-scope facilities.[38] However, the EPA notes that many power plants operate at very high load levels during most of their operating hours.[39] In fact, a substantial number of the plants affected by this rule – especially large nuclear and coal-fired facilities – are used as baseload plants and operate at or near their maximum power levels during a very large percentage of their operating hours. Therefore, EPA should use a higher load level to calculate turbine efficiency losses due to cooling system conversions. As discussed at length in the EBA and the Technical Development Document, the use of such higher load levels would reduce the turbine losses that could be expected from the conversion to a recirculating cooling system.

   On page 5-9 of the Technical Development Document, the Agency appears to confuse the concepts of a power plant's operating load level and its annual capacity factor. The Agency writes:

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[36] EBA, at page B1-9.

[37] Ibid.

[38] EBA, Table B1-1

[39] EPA writes: "The Agency understands, based on discussions with the Department of Energy, that a significant portion of existing power plants, when dispatched, would operate at near maximum loads." Technical Development Document, at page 5.2.

> The average capacity factor for nuclear power plants in the U.S. has been improving steadily and recently has been reported to be approximately 89 percent. This suggests that for nuclear power plants, the majority appear to be operating near capacity most of the time. Therefore, the use of the energy penalty factors derived from the maximum load curves for nuclear power plants is reasonably valid. In 1998, utility coal plants operated at and average capacity of 69 percent (DOE 2000). Therefore the use of energy penalty values derived from the 67 percent load curves would appear to be more appropriate for fossil-fuel plants.[40]

Operating loading is a description of how close to full load a plant is operating at a given moment. In contrast, a plant's capacity factor is a function of both the plant's load level during each hour *and* the number of hours operated. Thus, the 69 percent average capacity factor for fossil-fueled units does not indicate that these units tend to operate near 69 percent of full load. Most large fossil-fired steam plants operate at loadings above 69 percent during most of their hours of operation. The annual average capacity factor is brought down to 69 percent by forced and unforced outages – periods during which the plants are generating no electricity.[41] (In fact, if one assumes a month per year of downtime on average for fossil units, then they *must* be operating at loadings well above 69 percent in order to achieve an average capacity factor of 69 percent.) Correcting this conceptual error illustrates why energy penalties for the in-scope units should be calculated at a loading well above 67 percent.

3. The EPA has acknowledged that energy penalties for the West were not available at the time that its analyses were finalized. The IPM analysis for plants located in California therefore used the U.S. average. This overstated the energy penalty for these facilities.[42]

7. Repowering

Finding: There appears to be a contradiction between the definitions of "repowering" in the EBA and the Technical Development Document and the Federal Register Notice.

The EBA notes that "Repowering in the IPM consists of converting of oil/gas capacity to combined-cycle capacity."[43] However, the Technical Development Document and the Federal Register Notice have a much broader definition of repowering.[44] The EPA

40 Technical Development Document, at page 5-9.

41 Similarly, while the average annual capacity factor of the nation's nuclear units has been increasing in recent years, this reflects mainly reduced down time at nuclear units, not operation of the units at higher loadings when they operate.

42 EPA response to Kristy Bulleit Question No. 2.

43 EBA at page B3-8, footnote no. 11.

44 Technical Development Document, at pages 2.36 and 2.37.

should clarify which definition is being used and should be consistent in the application of that definition. In addition, as noted earlier, the EPA also should consider facilities that are converting from coal to combined-cycle capacity within its definition of repowering.

EPA makes the following observations at page 2.38 of the Technical Development Document:

> Because the Agency developed a cost estimating methodology that primarily utilizes design intake flow as the independent variable, the Agency examined the extent to which compliance costs would change if the repowering data summarized above were incorporated into the cost analysis of this rule. The Agency determined that projected compliance costs for facilities withdrawing from estuaries could be lower after incorporating the repowering changes. The primary reason for this is the fact that the majority of estuary repowering facilities would change from a steam cycle to a combined-cycle, thereby maintaining or decreasing their cooling water withdrawals (note that a combined-cycle facility will withdraw one-third of the cooling water of a comparably sized full steam facility). Therefore, the portion of compliance costs for regulatory options that included flow reduction requirements or technologies could significantly decrease if the Agency incorporated repowering changes into the analysis. As shown in Table 2-22 the majority of facilities projected to increase cooling water withdrawals due to the repowering changes use freshwater sources. In turn, the compliance costs for these facilities would increase if the Agency incorporated repowering for this proposal.[45]

The EPA should explain in detail precisely how it evaluated and quantified the potential impact of repowering for potentially affected facilities and provide the underlying analyses and data. The EPA also needs to consider the potential impact of the repowering of oil, gas, and coal-fired facilities to combined-cycle technology on the costs of complying with the alternative regulatory options. This is especially important because the EPA acknowledges that the "the portion of compliance costs for regulatory options that included flow reduction requirements or technologies could significantly decrease if the Agency incorporated repowering changes into the analysis."

Finding: The EPA appears to have failed to consider the repowering of coal-fired facilities to use combined cycle technology.

Synapse has conducted a literature search to identify electric generating facilities that have been repowered or that are currently planned to be repowered in the near future. This literature search consisted of reviews of such public sources as state public utility commission websites, utility and non-utility generator websites, the EIA Form 767 database, industry and other new publications, and the UDI database.

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[45] Technical Development Document, at page 2.38.

We found that at least 16 coal-fired facilities have repowered or are currently proposing to repower.[46] However, the EPA analyses appear to ignore such potential repowerings of coal-fired facilities.[47] In fact, many of these repowerings involve conversion to combined-cycle technology.

8. The Cost-to-Revenue Measure

Finding: The cost-to-revenue analyses presented in the EBA appear to overstate the magnitude of compliance costs relative to facility-level and firm-level revenues.

Because many of the underlying calculations and data have been designated CBI it is impossible to evaluate the cost-to-revenues measures presented in the EBA. Nevertheless, there are several reasons why the cost-to-revenue discussions in Chapters B7 of the EBA (and the results presented in Tables B7-4, B7-5, B7-9, B7-10, B7-14, B7-15, B7-19, and B7-20 of the EBA) overstate the magnitude of compliance costs relative to revenues.

First, as discussed in detail above, the costs of complying with the alternative scenarios have been overstated. This overstatement directly distorts the cost-to-revenue measures presented in the EBA and inflates the magnitude of the compliance costs relative to revenues.

Second, it is unclear from the EBA and the materials provided by the EPA whether the analyses reflect any increases in facility-level and firm-level revenues as a result of the passing through to consumers of cost increases resulting from the implementation of the proposed Phase II rule or any of the alternative regulatory options. This omission would be critical because it is reasonable to expect that firms, rather than being forced to bear all of these costs themselves, could pass along to their customers a significant portion, if not all, of the costs they incur in meeting any new Phase II EPA requirements and, thereby, recover these costs through increased revenues.

Those firms located in states in which electricity generation has not yet been deregulated would have an opportunity to file a rate case to recover any increased costs resulted from cooling system modifications or conversions. Those firms located in states in which deregulated electricity markets exist may be able to recover any Phase II-related costs through increases in market prices.

For this reason, the EPA should model scenarios where some or all of the costs of implementing the proposed Phase II rule or the alternative regulatory options are recovered through increased revenues.

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46 These repowerings and the related source documents are listed in Appendix A to these Comments.

47 "Repowering in the IPM consists of converting of oil/gas capacity to combined-cycle capacity." See the EBA at page B3-8, footnote no. 11.

9. Background Information on Synapse Energy Economics

Synapse Energy Economics, Inc. is a consulting firm specializing in public policy issues related to electricity industry planning and regulation, with an emphasis on consumer and environmental protection. Synapse provides research, reports, testimony and regulatory support primarily to state consumer advocates, regulatory commissions, energy offices and legislatures. Other clients include federal government agencies and environmental organizations. Areas of Synapse expertise encompass the many inter-related issues pertaining to electric industry regulation, such as market power, stranded costs, power plant economics and environmental impacts, renewable resources, energy efficiency, and electric system modeling, the regulation of distribution, mergers and acquisitions, divestiture plans and consumer aggregation.

Synapse currently has a staff of 12 individuals, including economists, engineers, lawyers and energy and environmental specialists. In approximately five years of existence, the company has successfully completed over one hundred consulting projects for clients including attorneys general (*Connecticut, Maine, Michigan, Mississippi, Washington*), state consumer advocates (*Connecticut, Maryland, New Hampshire, Vermont, West Virginia*), federal agencies (*U.S. Department of Energy, U.S. Environmental Protection Agency, U.S. Federal Trade Commission, and U.S. Department of Justice*) and various associations (*National Association of Regulatory Utility Commissioners, New England Conference of Public Utility Commissioners, New England Governors' Conference, Northeast States for Coordinated Air Use Management, and the State and Territorial Air Pollution Program Administrators*).

The Synapse team that prepared these comments includes David Schlissel, David White, Geoff Keith, and Michael Drunsic. Copies of these individuals' resumes are attached to this report.

Appendix A – Coal Plant Repowerings

Synapse has identified the following completed, underway and proposed coal plant repowerings:

Plant	Owner	Status	Source Document
Bergen	PSEG Power	Completed	Company website
Wabash River	Cinergy/PSI	Completed	Modern Power Systems, July 1996
Urquhart	South Carolina Gas & Electric	Completed	The Electricity Daily, August 19, 2002
Hawthorn Unit 5	Kansas City Power & Light	Completed	Power, May/June 2001
Grand Tower	Ameren	Completed	Global Power Report, April 4, 2000

Marion	Southern Illinois Power Cooperative	Under construction	Modern Power Systems, September 30, 2001
Seward	Reliant	Under construction	Power, March/April 2002, at page 36.
Black Dog	Xcel Energy	Under construction	Electric Utility Week, October 4, 1999, and Company website
Beaver Valley	AES Corp.	Proposed	Platts Coal Outlook, February 5, 2001
Port Washington	Wisconsin Energy	Proposed	Coal Week, August 6, 2001
Hutsonville Power Station	Ameren	Proposed	Modern Power Systems, April 30, 2000
Ashtabula	NRG	Proposed	Global Power Report, July 25, 2002
Noblesville	Public Service of Indiana	Proposed	Utility Environment Report, December 28, 2001
E.J. Stoneman Generating Station	Wisconsin Power	Proposed	Marketplace, May 22, 2001
Gannon	Tampa Electric	Proposed	Florida Public Service Commission Order in Docket No. 000686-EI, issued November 30, 2000
Possum Point	Dominion Resources	Proposed	Company website

David A Schlissel

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SUMMARY

I have worked for twenty-eight years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric Industry Restructuring and Deregulation - Investigated whether generators have been intentionally withholding capacity in order to manipulate prices in the new spot wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and auctions of power purchase agreements. Analyzed stranded utility costs in Massachusetts and Connecticut. Examined the reasonableness of utility standard offer rates and transition charges.

System Operations and Reliability Analysis - Investigated the causes of distribution system outages and inadequate service reliability. Evaluated the impact of a proposed merger on the reliability of the electric service provided to the ratepayers of the merging companies. Assessed whether new transmission and generation additions were needed to ensure adequate levels of system reliability. Scrutinized utility system reliability expenditures. Reviewed natural gas and telephone utility repair and replacement programs and policies.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Reviewed power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors. Evaluated the reasonableness of contract provisions and terms in proposed power supply agreements.

Nuclear Power - Examined the impact of industry restructuring and nuclear power plant life extensions on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates. Assessed the potential impact of electric industry deregulation on nuclear power plant safety. Reviewed nuclear waste storage and disposal costs. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than seventy proceedings before regulatory boards and commissions in twenty one states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001

Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, <u>Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company</u>, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. Senior Associate, 1996 to present. Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric industry restructuring, electric power system planning, performance-based regulation, stranded costs, system benefits, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, green marketing of electricity, environmental disclosure, climate change policy, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, fuel prices, dispatch modeling, economic analysis of power plants and resource plans, and risk analysis.

G-W Associates, Arlington, MA. Principal, 1985 to present.
Engineering and environmental analysis. Design and development of computer software. for scientific and engineering analysis. Design and implementation of database systems. Consulting on management information systems and operations research applications. Training and documentation for computer applications.

Tellus Institute, Boston, MA. Associate Scientist, 1980 to 1986.
Participated in a number of electrical demand forecast studies, specializing in the evaluation of the potential for energy conservation and co-generation. Developed methodologies and computer programs for evaluating energy conservation policies. Developed a computer modeling system (LEAP) for evaluating the resource needs of developing countries. Participated in international energy planning studies and conducted training programs in a number of African and European countries.

Massachusetts Institute of Technology Energy Laboratory, Cambridge, MA. Research Associate, 1975 to 1980. Participated in a several energy policy studies which evaluated the future demand and supply for electricity in the US. Designed and developed a mathematical programming model of the US coal and electric utility industries.

EDUCATION

Massachusetts Institute of Technology, Ph.D. 1980, Civil Engineering.
Case-Western Reserve University, M.S. Physics.
The University of Akron, B.S. Physics.

SUMMARY OF RELEVANT EXPERIENCE

David White is a consulting engineer specializing in computer-based analysis of energy and environmental systems. He has a Ph.D. from Massachusetts Institute of Technology in Civil Engineering Systems specializing in environmental studies, and B.S. and M.S. degrees in Physics. He has had over 20 years' experience as a consultant focusing primarily on energy and environmental issues with a focus on utility company operations with the MIT Energy Laboratory, Tellus Institute and Synapse. He has undertaken a wide range of U.S. and international studies evaluating energy usage, developing energy forecasts, evaluating conservation opportunities and assessing environmental impacts.

In addition to engineering and statistical analysis, Dr. White has designed and developed over the years a number of computer models for evaluating energy and environmental systems many of which are still in active use. Some recent computer models have been EXMOD for evaluating the impacts and externalities from power plants, and ELMO for evaluating the market power potential of electric utility systems. Other recent work has been the development of a methodology for tracking the environmental characteristics associated with deregulated electricity sales which is being considered by a number of ISO's. The results of these models have provided the basis for a number of reports and testimonies.

Dr. White has also worked on a number of non-energy software development projects and has taught computer software and modeling courses at a number of Boston area universities.

PUBLICATIONS

Avoided Energy-Supply Costs for Demand-Side Management Screening in Massachusetts, a Resource Insight report for the AESC Study Group, by Rachel Brailove, Paul Chernick, Susan Geller, Bruce Biewald, and David White, July 7, 1999.

Stranded Nuclear Waste: Implications of Electric Industry Deregulation for Nuclear Plant Retirements and Funding for Decommissioning and Spent Fuel, by Bruce Biewald and David White, January 15, 1999.

The Role of Ozone Transport In Reaching Attainment in the Northeast: Opportunities, Equity and Economics, a Synapse Energy Economics report for the Northeast States for Coordinated Air Use Management, by Tim Woolf, David White, Bruce Biewald, and William Moomaw, July 1998.

Grandfathering and Environmental Comparability: An Economic Analysis of Air Emission Regulations and Electricity Market Distortions, a Synapse Energy Economics report for the National Association of Regulatory Utility Commissioners, by Bruce Biewald, David White, Tim Woolf, Frank Ackerman, and William Moomaw, June 11, 1998.

Analysis of Market Power in the APS and Duquesne Service Territories, prepared for the Maryland Office of People's Counsel, by Bruce Biewald and David White, February 9, 1998.

Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis, prepared for the New England Conference of Public Utility Commissioners, by Bruce Biewald, David E. White, and William Steinhurst, June 11, 1997 (a draft was published as Vermont DPS Technical Report No. 39 in March, 1997).

Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information, a Regulatory Assistance Project report funded by the Pew Charitable Trusts, the Joyce-Mertz Gilmore Foundation, the U.S. EPA, and the U.S. DOE, by David Moskovitz, Tom Austin, Cheryl Harrington, Bruce Biewald, David E. White, and Robert Bigelow, March 1997.

"Follow the Money: A Method for Tracking Electricity for Environmental Disclosure," Bruce Biewald, David White, and Tim Woolf, The Electricity Journal, May 1999.

"Implications of Premature Nuclear Plant Closures: Funding Shortfalls for Nuclear Plant Decommissioning and Spent Fuel Transportation and Storage," Bruce Biewald and David White, prepared for the United States Association for Energy Economics and International Association for Energy Economics, 19th Annual North American Conference, Albuquerque, NM, October 1998.

"Counting the Costs: Scientific Uncertainty and Valuation Perspective in EXMOD," Stephen Bernow, Bruce Biewald, William Dougherty, and David White, presented at technical meeting of the International Atomic Energy Agency, Vienna, Austria, December 4-8, 1995.

New York State Environmental Externalities Cost Study, a Hagler Bailly Consulting report prepared for the Empire State Electric Energy Research Corporation (ESEERCO), by R.D. Rowe, C.M. Lang, L.G. Chestnut, D.A. Latimer, D.A. Rae, S.M. Bernow, D.E. White, Oceana Publications, December 1995.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge, MA. Research Associate, 2001-present. Area of focus includes environmental and economic analysis related to power generation projects, energy policy and environmental policy. Assesses costs and benefits of renewable resources and distributed generation and the environmental aspects of power plant proposals and energy market structure.

M. J. Bradley & Associates, Concord, MA. Environmental/Energy Consultant, 1996-2001.
Worked with environmental advocates and energy companies in support of more stringent air regulations and energy policies supporting clean energy technologies. Facilitated strategic partnerships to address regulatory and market barriers to clean distributed generation. Participated in regulatory and legislative proceedings relevant to renewable resources and distributed generation and coordinated communication between technology developers, advocates and energy and air regulators.

Rhode Island Division of Public Utilities and Carriers, Providence, RI. Policy Analyst, 1995-1996. Analyzed the economic and environmental implications of restructuring strategies. Helped facilitate the Rhode Island Electric Industry Restructuring Collaborative and co-authored the Division's restructuring plan.

Institute for Resource and Security Studies, Cambridge, MA. Intern, 1992. Managed research projects including the creation of a sustainability database for the City of Cambridge and a report on energy use in the city.

National Outdoor Leadership School, Lander, WY. Field Instructor, 1989-1990. Completed instructors training program. Responsibility for the safety and education of students on 30-day wilderness expeditions in Alaska. Organized and led a 30-day trek in the Himalaya.

EDUCATION

Masters, Environmental Studies. Brown University, Providence, RI, 1995.
Graduate Work, Science and Economics. Harvard Extension School, Cambridge, MA, 1993.
Graduate Work, English. Middlebury College, Middlebury, VT, 1991-1992.
B.A., English. Tufts University, Medford, MA, 1988.

RECENT REPORTS

Distributed Resources and their Emissions: Modeling the Impacts, report co-authored with the Natural Resources Defense Council and Institute for Lifecycle Analysis, draft released in April 2001.

Utility Tariffs and Charges Affecting Distributed Generation, inventory and report prepared for the Natural Resources Defense Council, August, 2000.

Fuel Cells: Clean, Reliable, Onsite Generation, educational materials prepared for the Northeast Fuel Cell Work Group, March 2000.

Emissions Trading and Fuel Cells: Issues and Opportunities, prepared for the Northeast Fuel Cell Work Group, April 1999.

Lead author of chapters on renewable and fossil-fired electricity generation for the report, *Reducing Greenhouse Gases and Air Pollution: A Menu of Harmonized Options*, published by STAPPA/ALAPCO in 1999.

Benchmarking the Air Emissions of Electric Utility Generators in the Eastern United States, co-authored with the Natural Resources Defense Council and Public Service Electric & Gas in 1996.

PRESENTATIONS

Potential Emissions from Diesel Generators, presentation at the Globalcon Energy Conference on Energy Technology and Policy, Atlantic City, New Jersey, March 2001.

Capacity Crises and Air Emissions, presentation at the Electric Utility Environmental Conference, Tucson, Arizona, January 2001.

Lessons from Existing Credit Trading Programs, presentation at NYSERDA/ASERTTI Conference on Developing Tradable Credits for Renewable Energy, Lake George, New York, October 2000.

Clean Energy Opportunities and Barriers, presentation at a roundtable meeting of New York State Legislature on Energy and Environmental Technologies, Albany, New York, May 2000.

Coordinating Energy and Environmental Policy to Support Clean Energy, presentation at the OTC/ECOS Environmental Technologies Conference, Pittsburgh, Pennsylvania, June 1999.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge, MA. Research Associate, 2002-present

Specialized in renewable energy issues, policy analysis, analysis of PROSYM runs.

Boston University, Teaching Fellow, Geography Department, Boston, MA, Spring 2002

Taught introductory environmental science.

Merck Family Fund, Intern, Milton, MA, Summer, 2001

Researched environmental issues, managed grants database, updated website, and published the Fund's quarterly newsletter. Researched the economic, social, and environmental values of green space for the Greening of Boston, a coalition exploring the current state and future of Boston's green space.

Arthur D. Little, Chemist, Cambridge, MA, Spring, 2001

Used EPA extraction methods to prepare sediment, water, and tissue samples for analysis for various toxins.

EDUCATION

Boston University, Boston, MA 2001-2002

Master of Arts in Energy and Environmental Analysis

Fields of study: Energy economics, econometrics, environmental policy analysis, ecological economics, dynamic systems modeling, statistical analysis, risk analysis

Bates College, Lewiston, ME 1994-1998

Bachelor of Science in Biology, *Cum Laude*

Courses in ecology, environmental studies, and the liberal arts.

School for International Training, Tanzania, East Africa Spring, 1997

Studied wildlife ecology and conservation issues, as well as local culture and language.

PUBLICATION AND PROJECTS

Analyzed the effect OPEC quotas have on world oil prices using econometric techniques, with Robert Kaufmann, Boston University Spring, 2002. Publication pending further study.

Generated a computer model of the net energy associated with photovoltaic modules and the carbon dioxide mitigation potential of photovoltaics. Fall, 2001

Conducted a risk-based critique of the Environmental Protection Agency's 2001 arsenic standard for drinking water. Fall, 2001