IN THE UNITED STATES DISTRICT COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

LUMINANT GENERATION CO., LLC, et al.	)
	)
Petitioners,	)
	)
v.	)
	)
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.	)
	)
Respondents.	)

DECLARATION OF
BRUCE E. BIEWALD

(1) My name is Bruce Edward Biewald, and all of the statements made in this declaration are based on my personal knowledge.

(2) I am the President of Synapse Energy Economics Inc., a consulting company in Cambridge, Massachusetts specializing in analysis of electric power systems. I have thirty years of experience advising state agencies, consumer and environmental advocates, utilities and others on issues related to the production and consumption of energy. I have testified in more than one hundred utility regulatory proceedings in twenty-six states and two Canadian provinces, in cases in state and federal Courts, and in proceedings of the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission's Atomic Safety and Licensing Board. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the US Department of Energy, the US Environmental Protection Agency, the Office of Technology Assessment, the Ozone Transport Commission, the New England Governors' Conference, the New England Conference of Public Utility Commissioners,

the National Association of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly*, and numerous conference proceedings.

(3) As president of Synapse Energy Economics, I oversee a staff of twenty-five individuals, conducting many dozens of consulting assignments each year. Our work includes consulting projects dealing with power plant costs and performance, electric power system reliability, generation asset valuation and divestiture, electric industry restructuring, stranded costs, system benefits, market power, mergers and acquisitions, rate cases, power supply contracts and performance standards, renewable power generation, demand-side management, air emissions from power plants, and electricity market simulation modeling for price forecasting and market power analysis. Synapse's governmental clients include federal agencies such as the Environmental Protection Agency, state Attorneys General, Consumer Advocates, utility regulatory commissions, and a variety of cities and towns. We also work for a number of non-governmental consumer advocates and environmental organizations, as well as associations of agencies, foundations, and private clients.

(4) Prior to founding Synapse, I was with Energy Systems Research Group (later Tellus Institute) where I was the manager of the electricity program, and consulted on a wide range of electric system regulatory and economic issues. I have a B.S. from the Massachusetts Institute of Technology where I studied Architecture, Building Technology, and Energy Use in Buildings. Appendix A contains my resume, which includes a listing of past testimony, papers, and reports.

(5) I have been asked to examine documents related to the Declaration of Warren P. Lasher, focusing on the assumptions and methodologies underlying Mr. Lasher's conclusions.

(6) In the paragraphs that follow I discuss ERCOT system reliability, weather impacts, demand- and supply-side resources in ERCOT, Cross-State Air Pollution Rule (CSAPR) obligations and compliance flexibility, and Luminant's financial and market context.

ERCOT System Reliability

(7) Mr. Lasher's September 15 declaration in this matter, and his Exhibit 1 (the ERCOT report on "Impacts of the Cross-State Air Pollution Rule on the ERCOT System, September 1, 2011), deal with a complex subject in a highly simplified manner. Specifically, the issue of reliably serving Texas electricity loads is a matter of probability analysis that should be addressed using sophisticated computer models. These computer models can actually simulate the reliability of the power system over the course of a year, and address key questions quantitatively. ERCOT has the capability of analyzing its system reliability in a rigorous manner, and indeed has done so in the past.

(8) A proper analysis of system reliability would use a probabilistic simulation model. Some background on power system reliability modeling is provided in Appendix B, a paper that I wrote with Stephen Bernow in 1988 for a conference of the National Regulatory Research Institute. The inputs to a reliability model would include hourly system loads and the capacity ratings and outage rates for all of the available generating units. The outputs would include reliability measures such as the number of expected annual "loss-of-load-events" (or "LOLEV"), the expected annual "loss-of-load-hours" (or "LOLH"), and the expected annual "unserved energy" ("EUE"). Indeed, ERCOT applied just such

a model in November 2010 when it conducted its "2010 ERCOT Target Reserve Margin Study." That analysis adopted a system reliability criterion of 0.1 LOLEV. This is an industry standard, typically referred to as "one day in ten years loss of load expectation." This analysis also included load uncertainties due to weather using a probabilistic methodology that simulated five different load scenarios including "extreme summer." Based upon this sophisticated modeling, the study found that the reliability criterion was satisfied at an ERCOT system reserve margin of 13.75%. At the ERCOT Board of Directors meeting on November 16, 2010, the Board "authorized and approved" the 13.75% target reserve margin for ERCOT.[1]

(9) In contrast to that system reliability analysis, the September 1, 2011 ERCOT report on "Impacts of the Cross-State Air Pollution Rule on the ERCOT System" is an overly simplistic and inadequately supported report. It starts with the assumption that the Monticello units will be retired, based on "information provided by the resource owners." It then calculates quantities of lost MW during different on-peak and off-peak time periods. The report's conclusion is that "…the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users."[2]

(10) The report includes no probability analysis and no computer modeling. It does not consider the LOLEV or LOLH or EUE measures of system reliability. It does not even contain numbers for the expected system load (demand) or the total capacity available

[1] ERCOT Board of Directors Meeting, Agenda Item No. 7, November 16, 2010. ERCOT News: November Board Meeting Highlights, "Target reserve margin for planning forecasts increased to 13.75 percent," November 17, 2010.
[2] Impacts of the Cross-State Air Pollution Rule on the ERCOT System, September 1, 2011, page 7.

before or after the Monticello units would reportedly be idled. The document has an alarmist tone, but provides no basis for understanding whether and to what extent the capacity losses predicted in the document might actually cause capacity to fall below target reserve levels or to jeopardize system reliability.

(11) Mr. Lasher's declaration adds some detail to the information in the report to help in understanding ERCOT system reliability. He points out that after the anticipated capacity reductions that ERCOT expects to have 73,665 MW in 2012, and he shows a generic graph of the "annual loss of load events" as a function of system reserve margin.[3] He does not, however, put the pieces together to explain what the expected reserve margin for the ERCOT system is for 2012 and beyond. Nor does he estimate any measures of system reliability (e.g., LOLEV, LOLH, or EUE). Such quantitative measures are necessary to understand the status of ERCOT system reliability and the expected impacts of CSAPR. Instead, Mr. Lasher takes us back to August 2011, with its extreme weather and record system peak demand, and points out that if ERCOT had been without 1,200 MW (Luminant's Monticello capacity) during that particular weather event then the situation would have been worse. He does not, however, provide his outlook of what system reliability in 2012 is expected to be in terms of the system reserve margin or any of the reliability metrics.

(12) ERCOT's other documents indicate that ERCOT expects to have capacity in 2012 in excess of its reserve margin target, even with Luminant's idling of Monticello 1 and 2. The available numbers indicate that reliability should meet the system's criterion. The

[3] Declaration of Warren P. Lasher, USCA Case# 11-1315, September 15, 2011, page 9.

forecast firm load for 2012 is 63,880 MW.[4] The total of capacity resources is expected to be 75,065 MW, for a reserve margin of 17.5%. This compares favorably with the 13.75% target reserve margin. With the loss of 1,400 MW predicted by ERCOT based primarily on Luminant's assertions, the total system capacity resources would be decreased to 73,665 MW. This is the number reported by Mr. Lasher as ERCOT's estimate of "available capacity in 2012" after the reductions. Even at this reduced level of capacity, the reserve margin would be 15.3%. This is still in excess of the 13.75% ERCOT target reserve margin, which itself is designed to provide adequate system reliability recognizing load uncertainty (which in turn is caused primarily by weather variability) and generating unit outages.

Weather Impacts

(13) Mr. Lasher states that if the summer of 2012 has similar loads and weather as 2011, then ERCOT reliability would be challenged. This is not the usual manner to treat weather risks in system planning.

(14) It is more usual, and more reasonable, to consider weather risks probabilistically. System forecasters generally will attempt to understand the relationships between weather and load, and to produce "weather normalized" forecasts. Then, probabilistic tools can be used to assess system reliability under expected loads, and for scenarios with higher and lower loads.

(15) This is precisely what ERCOT did in its "2010 ERCOT Target Reserve Margin Study." That analysis specifically focused on the question of what reserve margin ERCOT should

[4]Report on the Capacity, Demand, and Reserves in the ERCOT Region, Revision 2," June 9, 2011, page 7.

use for planning, recognizing weather/load uncertainty and generating unit outages. ERCOT has also analyzed the effect of weather on its system peak demands.

(16) Figure 1, below, copied from a 2011 ERCOT planning study, shows ERCOT's calculation of the forecast peak for 2011 assuming different "weather years" ranging from the mild summer experienced in 2004 to the hotter summer peak in 2010.[5] The variability of the expected peak demand ranges from 60,258 MW based on 2004 weather data to 66,553 MW based on 2010 weather data.

Figure 1. Effect of Various Base Weather Years on Peak Forecast, 2004 - 2010

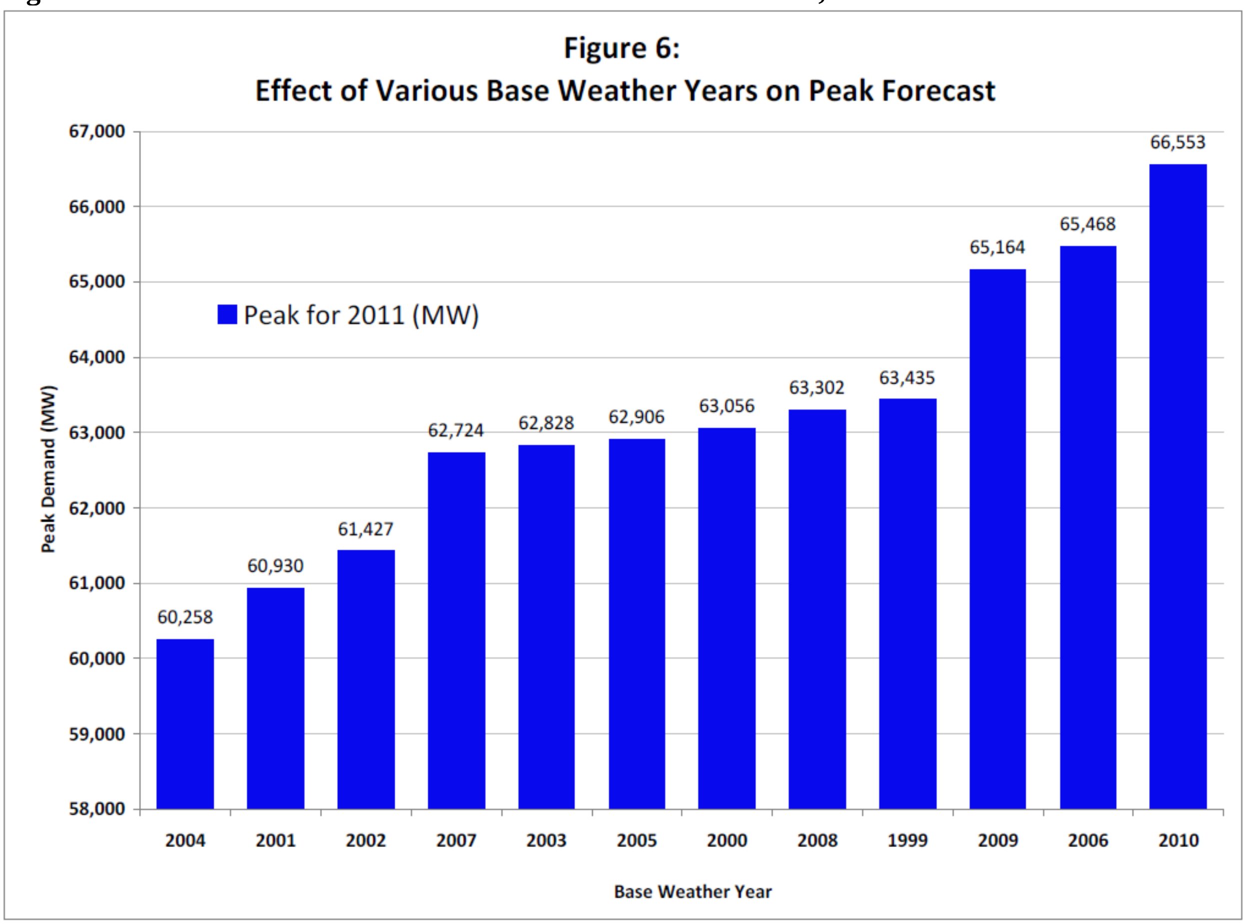

Image source: 2011 ERCOT Planning: Long-Term Hourly Peak Demand and Energy Forecast. June 30, 2011. Page 12.

[5] 2011 ERCOT Planning: Long-Term Hourly Peak Demand and Energy Forecast, June 30, 2011, page 12, Figure 6

(17) Figure 2, below, is similar to Figure 1 above, but includes more years of historical data, as well as the 2011 summer peak, which turned out to be higher than any in the historical period since 1996. What this shows is that with typical or normal weather, the peak in 2011 would have been in the neighborhood of 63,000 MW, or about 7,000 MW (or ten percent) lower than the experienced peak. ERCOT planners should recognize the latest data in their models, and they should take very seriously the responsibility to plan in a manner that loads will be served reliability. However, they should not assume that the summer of 2012 will experience the same weather and loads as 2011, as Lasher does.

Figure 2. Effect of Various Base Weather Years on Peak Forecast, 1996 - 2011

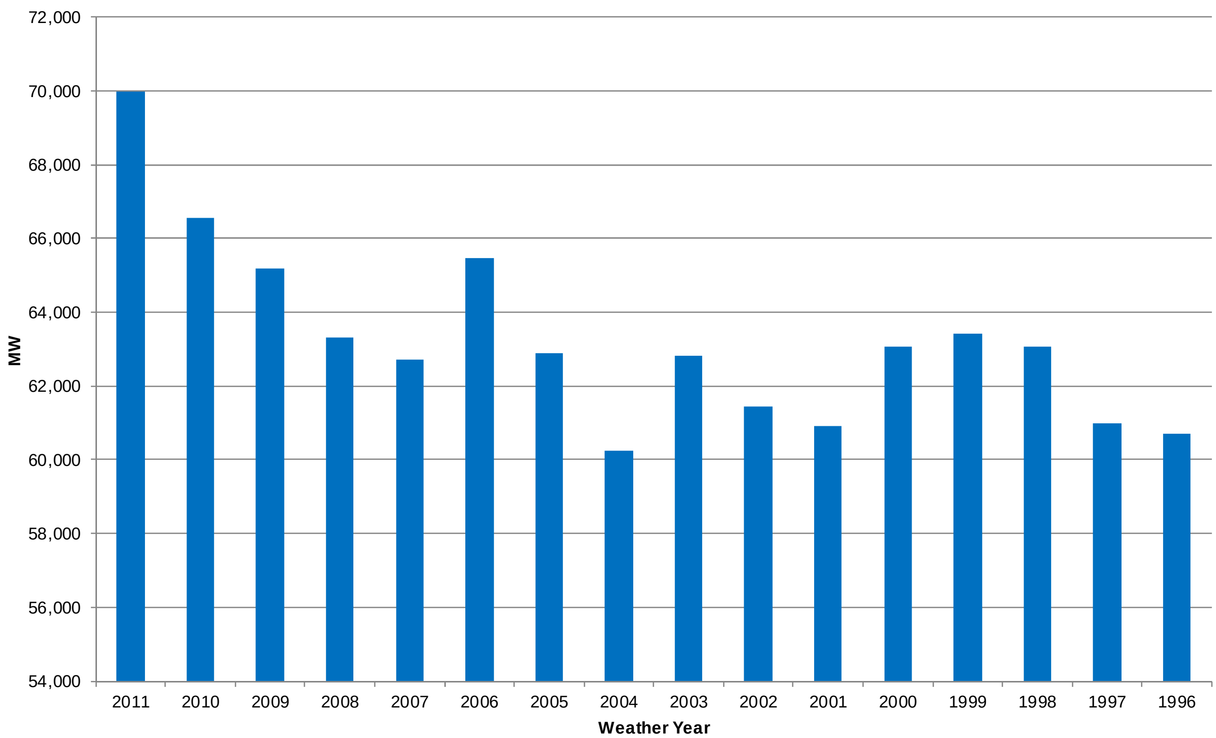

Image source: Opheim, Calvin. ERCOT: Development of Long-Term Load Forecast Scenarios. September 9, 2011. Page 7.

(18) In an August 30, 2011 document from ERCOT, the longer term capacity and reserve requirements are presented in a clear and coherent manner. Page 3 from that document is reproduced here as Figure 3. That figure shows the annual reserve margins for past actual and future forecasted years. It shows the reserve margin target increasing from 12.5% to 13.75% as a red line, and it shows the existing and future generating capacity as a percent of load. According to this projection, which presumably includes the Monticello units as operable, the system reserve requirement is exceeded by about 4 percentage points in 2012 (reading by eye from the figure) without consideration of the large amount of "planned generation under full interconnection studies."

Figure 3. ERCOT annual reserve margins for past actual and future forecasted years

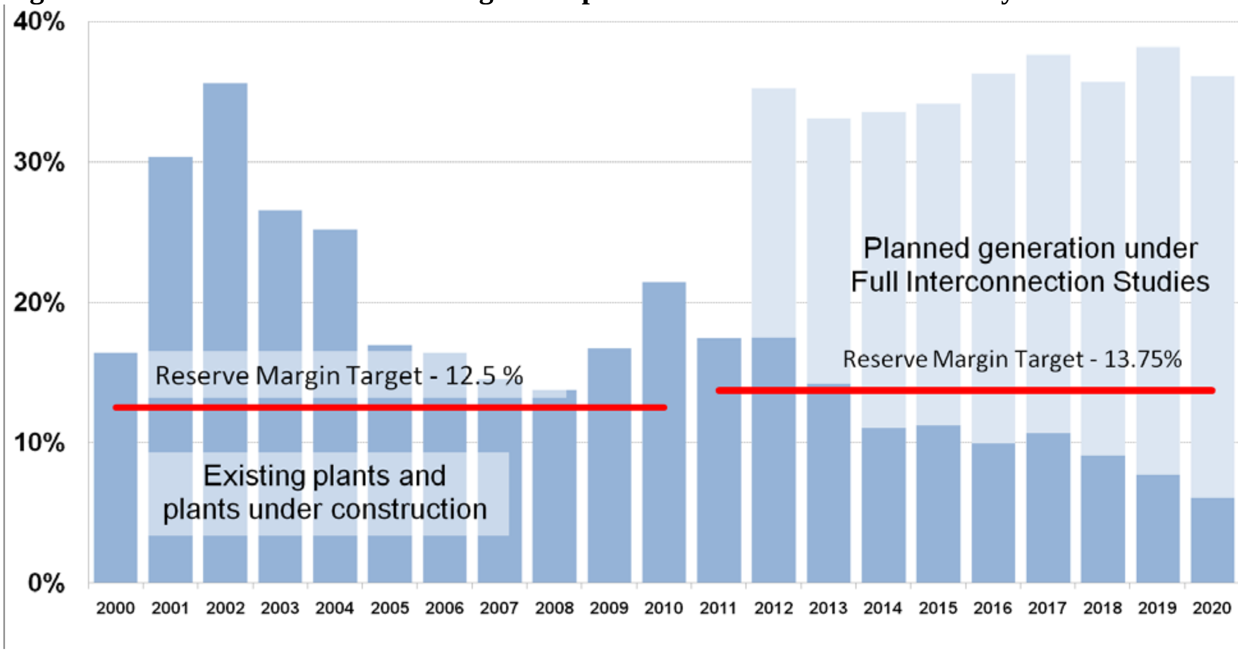

Image source: Wattles, Paul. ERCOT Demand Response Overview & Status Report. AMIT-DSWG Workshop 'AMI's Next Frontier: Demand Response.' August 30, 2011. Page 3.

(19) It is not particularly unusual for a power system to need new capacity in the future to meet its reserve margin target. This is quite normal for a system with projected growing loads.

Demand- and Supply-Side Resources in ERCOT

(20) Other resources are not incorporated into ERCOT's reserve margin calculation because they are not immediately available. However, some of these resources could contribute to future capacity if needs arise. ERCOT's "Report on Capacity, Demand and Reserves in the ERCOT Region" in May 2011 refers to "other potential resources" including 2,447 MW of "mothballed capacity" and 8,200 MW of "planned units in full interconnection study phase" in 2012. The latter category increases from year to year peaking at 19,861 MW in 2019. While many of these "planned units" will never be built, the size of this queue suggests a robust interest in developing new generating projects in Texas. If there is a need for capacity in terms of system reliability or market economics, then surely a substantial portion of this capacity could be built.

(21) Units in "mothballed" status are not permanently closed but kept idle so that they can be activated with advance notice. For instance, after the extreme heat in early August of 2011, ERCOT activated four mothballed units at the Spencer and Sam Bertron plants for several months.[6] These units provided 400 MW of capacity available for system reliability during emergencies. Other plants can come online just for the summer since it becomes more economical to run during these peak periods. Recently, NRG Energy brought back its Greens Bayou plant out of mothballed status to run in the summer

[6] ERCOT Press Release, August 16, 2011, "ERCOT Announces Temporary Contracts to Add Generation during Current Extreme Heat, Drought."

months.[7] In the future, there are other mothballed units that could be made available should ERCOT decide to reactivate them. According to an ERCOT vice president, “there’s another 2,000 megawatts of mothballed capacity we can call on.” [8] While this capacity is not available tomorrow, it could, I expect, be made available for the summer of 2012 or the summer of 2013 should ERCOT decide between now and that time to plan for ensured reliability.

(22) The planned projects in ERCOT are another potential source of future capacity. ERCOT’s “Report on Capacity, Demand and Reserves in the ERCOT Region” in May 2011 lists 8,200 MW of potential resources for 2012—mostly from 6,000 MW of natural gas and nearly 1,200 MW of wind.[9] ERCOT’s System Planning report from August 2011 lists these gas projects as “undergoing full interconnection studies” with commercial operation delivery (COD) dates for some slated for late 2011 and early 2012, including: a 275 MW gas plant in Ector County (May 2012), a 646 MW gas plant in Grayson County (November 2011), and a 550 MW gas plant in Madison County (March 2012).[10] (The rest of the 6,000 MW new gas projects have COD’s that are “to be determined.”)

(23) Mr. Lasher talks briefly about future supply additions but does not factor any of the potential capacity into his argument. He proceeds to portray a grim scenario of “rolling blackouts” and “persistent power shortages” while neglecting to mention the contingencies that ERCOT has available.

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[7] “Shaking off the cobwebs: mothballed power plants will come back online,” Fuel Fix, August 16, 2011.
[8] “Power problems might be worse next year,” San Antonio Express-News, August 24, 2011.
[9] The megawatts of wind are calculated by taking the total MW of installed wind multiplied by ERCOT’s wind capacity value of 8.7%.
[10] ERCOT System Planning , Monthly Status Report, August 2011.

(24) To address system reliability concerns, ERCOT could also aggressively develop the untapped demand response (DR) resources in Texas. Some additional DR resources could be achieved for the summers of 2012 and 2013 if Texas chose to emulate the efforts of other states.

CSAPR Obligations and Compliance Flexibility

(25) In addition to supply- and demand-side resources available in ERCOT, provisions in CSAPR, normal operation of the electricity markets in the ERCOT region, and backstop mechanisms to ensure reliability will all ensure that CSAPR does not threaten the reliability of the electric system in the ERCOT region of Texas.

(26) The regulations provide compliance flexibility, enabling affected unit owners to determine the best compliance path for individual units within their fleet, and for their fleet overall. These are business decisions to be made by the power plant owners. Luminant's obligation, like other generating unit owners, is to hold an allowance for every ton of SO_2 or NO_x that it emits, and to avoid causing the state to exceed the state assurance budget. Luminant, like other generating unit owners, has multiple options for meeting its obligations. In the near-term, it can operate its units up to its allocated allowances (by changing the unit dispatch and generation, switching to low sulfur coal, or operating existing controls), or it can seek to purchase additional allowances. Following the end of the control period (December 31 for the annual SO_2 and NO_x trading programs, and September 30 for the seasonal NO_x trading program), there is a three-month window during which covered sources can review their emissions for the control period and trade allowances as necessary. By coordinating within its own fleet and with

other generating unit owners, it can ensure that it does not cause an exceedance of the state assurance budget. Luminant will decide the most economic course of action for its units taking into account regulatory obligations under CSAPR and other programs, market dynamics, and other investment opportunities.

(27) While individual generation owners must determine the economic course of action for their individual units and generation fleet, the electric sector is exceptionally well prepared to assure reliable service despite myriad factors and changing circumstances. The electric sector comprises multiple market-based, operational, and regulatory mechanisms that demonstrate the primacy of reliability and resource adequacy, and ensure that reliability and resource adequacy are maintained. Electric markets are designed to provide for smooth entry of new resources and smooth exit of non-economic existing resources. Markets in the electric sector incorporate specific tools for managing transition from aging, uneconomic resources to newer, competitive resources—for example, demand response, changes in the operation of existing units, and transmission responses to identified constraints all play a role.

(28) In recent years, the Texas RTO (ERCOT), its regulators, and market participants have made important changes in the markets that will enhance the market's efficiency and resilience. For example, in December 2010, ERCOT moved to a nodal market rather than a zonal market for wholesale electric market transactions. According to ERCOT, a nodal market improves price signals, and affects the profitability of new units.[11] ERCOT has also recently made changes to enable locational marginal prices to be posted before

[11] See, e.g. ERCOT; State of the Markets Report; August 2011.

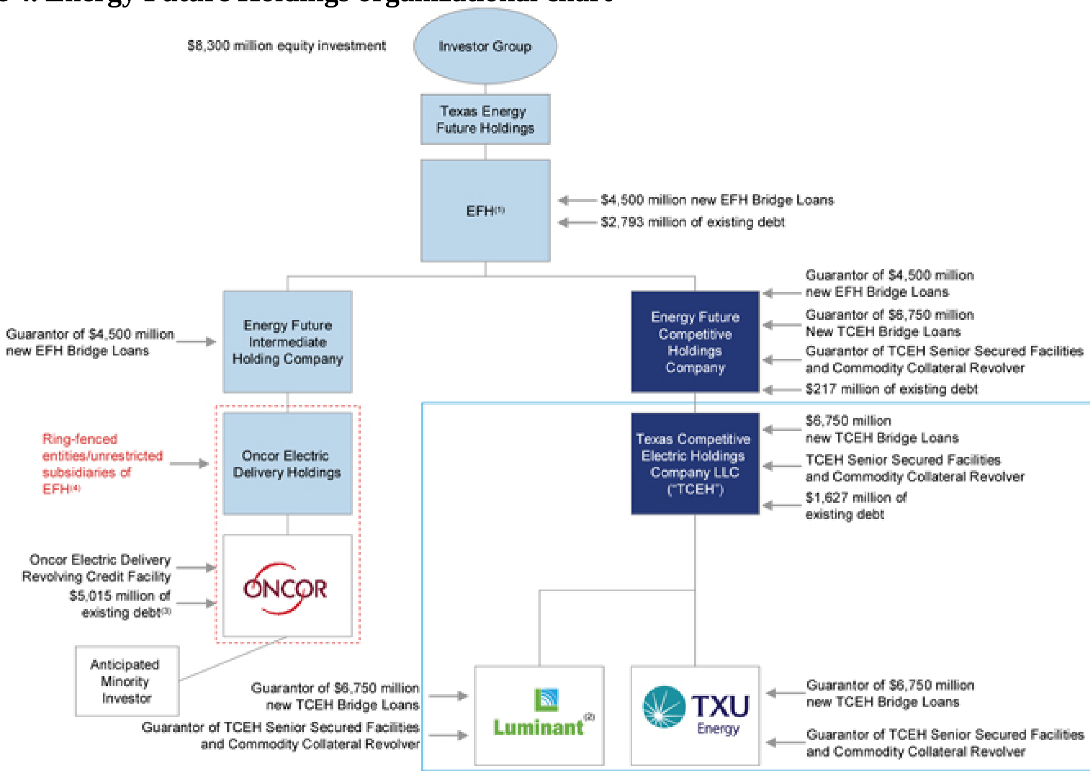
each interval, thus enabling demand response to market prices.[12] ERCOT has also made the use of its transmission system more efficient in response to transmission constraints into the Houston zone.[13] Finally, price spikes in the Texas market provide an important signal and incentive for the entry of new resources into the market.[14]

Luminant's Financial and Market Context

(29) The biggest private equity buyout in history occurred on February 25th 2007. TXU Corporation (now known as Energy Future Holdings) was purchased by a group of firms including Kohlberg Kravis Roberts (KKR), Texas Pacific Group (TPG), and Goldman Sachs for $45 billion. Additional equity holders in this deal included Citigroup, Morgan Stanley, and Lehman Brothers. Shareholders were offered a 20% premium above the previous day's market value.[15] As a result of this deal, each of TXU's operations was broken into three companies in the following way: new companies named Luminant and Oncor would handle generation and distribution, respectively, while the TXU name would remain associated with the retail operation.[16] An organizational chart from the company's SEC filing shows these relationships:

[12] Public Utility Commission of Texas; Scope of Competition in Electricity Markets in Texas; a report to the Texas Legislature, January 2011. P. 26.
[13] Id. p. 49.
[14] Id. pp. 43 ff.
[15] Luminant Press Release, February 26, 2007, "TXU to Set Direction as Private Company."
[16] Ibid.

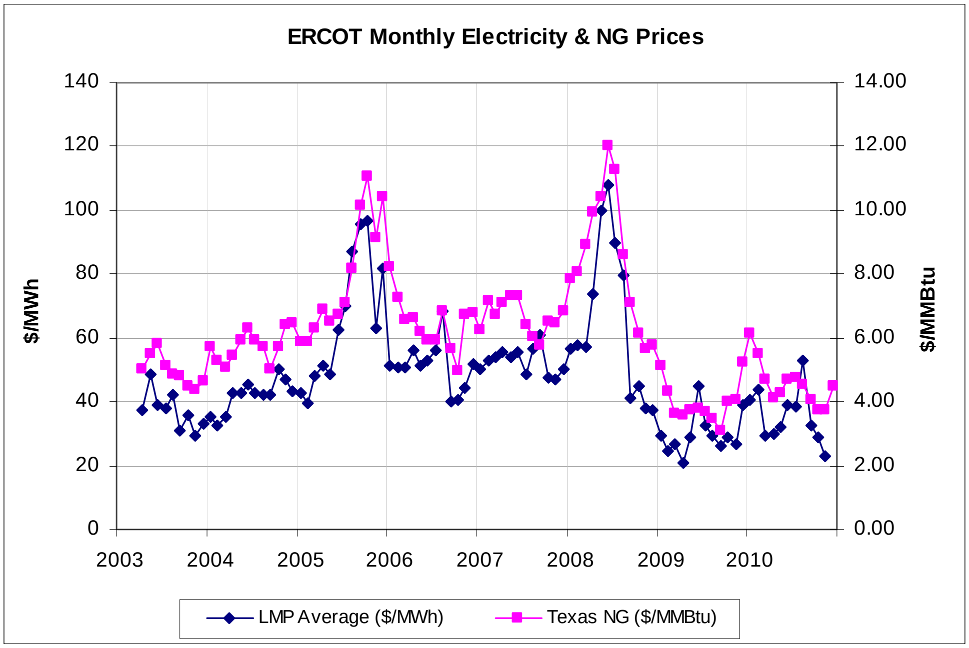
Figure 4. Energy Future Holdings organizational chart



Source: Energy Future Holdings Corp, 8-K filing with SEC, 10/15/07

(30) However, the value of the deal has dropped precipitously since 2007. This decline in value can be partially attributed to a decrease in natural gas prices, which track closely with wholesale electricity prices. The chart below shows the close correlation between the two prices:

Figure 5. Correlation between natural gas prices and wholesale electricity prices



Source: ERCOT Hourly Load Data Archive, ERCOT Balancing Energy Services Market Clearing Prices Archive, EIA-423 Electric Power Monthly.

(31) As seen in the chart above, natural gas prices at the time of the deal were between $7 per MMBtu and $8 per MMBtu. The company knew that its revenue was significantly dependent on natural gas price movements, and tried to hedge against future price movements[17]:

> The strong historical correlation between natural gas prices and power prices in ERCOT combined with significant liquidity in certain natural gas markets currently provides an opportunity for management of TCEH's exposure to natural gas prices. As a result, TCEH plans to hedge up to 80% of the equivalent natural gas price exposure of its expected baseload generation output on a rolling five-year basis. As of *October 10, 2007*, approximately 2.6 billion MMBtu of natural gas (equivalent to the natural gas exposure of over 300,000 GWh at an assumed 8.5 MMBtu/MWh market heat rate) have been effectively sold forward over the period from 2008

[17] Form 8-K, Energy Future Competitive Holdings Company, 8-K Current Report, filed on February 15, 2007.

to 2013 at **average annual prices ranging from $7.25 per MMBtu to $8.15 per MMBtu.**

(32) However, after a surge in 2008, natural gas prices have since dropped—hovering between $4 per MMBtu and $5 per MMBtu. As a result, electricity prices have decreased accordingly in Texas, leading to a significant drop in revenues for Energy Future Holdings. According to the company's own 2010 SEC 10-K filing[18]:

> Operating revenues decreased $1.876 billion, or 19%, to $7.911 billion in 2009. **Wholesale electricity revenues decreased $1.732 billion, or 56%, to $1.383 billion in 2009 as compared to 2008**. Volatility in wholesale revenues and purchased power costs reflects movements in natural gas prices, as lower natural gas prices in 2009 drove a 46% decline in average wholesale electricity sales prices.

(33) The overestimation of natural gas prices and resulting depression in electricity revenues have contributed to the company's immense debt. Currently, the company is carrying over $36 billion in debt, of which $22.5 billion will mature in 2014.[19] The company's own financial reporting lays out its dire situation, admitting that soon it may not be able to meet its obligations[20]:

> EFCH's ability to make scheduled payments on its debt obligations depends on EFCH's financial condition and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond EFCH's control, including, without limitation, wholesale electricity prices (which are primarily driven by the

[18] Form 10-K, Energy Future Competitive Holdings Company, 10-K Annual report pursuant to section 13 and 15(d), filed on February 18, 2011.
[19] "Texas-Size Woe for KKR, TPG," Wall Street Journal, March 8, 2011.
[20] Form 10-K, Energy Future Competitive Holdings Company, 10-K Annual report pursuant to section 13 and 15(d), filed on February 18, 2011.

price of natural gas and ERCOT market heat rates). **EFCH may not be able to maintain a level of cash flows sufficient to permit it to pay the principal, premium, if any, and interest on its debt.**

(34) The largest leveraged buyout in U.S. history has proven to be a failure. An investment of $45 billion based largely on the premise of sustained or increasing natural gas prices left exposure to huge risks should prices drop. Now that this risk has been realized, the value of the original deal has dropped significantly. Two of the buyout's own originators agree that it is worth far less than the original purchase price. KKR estimates its share at 20% of its original value, while TPG estimates 40%.[21]

(35) While environmental regulations play a role, it is market conditions—and in particular the wholesale prices for energy in ERCOT, along with the company's business strategy—that are the key drivers of Luminant's financial situation generally, and of the economics of operation of the Monticello coal units in particular.

[21] "A Portfolio's Price," New York Times, January 4, 2011.

I declare under penalty of perjury that the foregoing is true and correct.

Bruce E. Biewald

Executed on October 6, 2011 in Cambridge, Massachusetts.

APPENDIX A
BIEWALD RESUME

Bruce Edward Biewald
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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. President, 1996 to present.
Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric power system planning, air emissions, climate change policy, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, nuclear plant decommissioning and radioactive waste issues, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, dispatch modeling, economic analysis of power plants and resource plans, portfolio management, risk analysis and risk management.

Tellus Institute, Boston, MA. Senior Scientist and Manager of the Electricity Program, 1989 to 1996, Research Associate and later Associate Scientist, 1980-1988.
Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.

EDUCATION

Massachusetts Institute of Technology,
BS 1981, Architecture, Building Technology, Energy Use in Buildings.
Harvard University Extension School,
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Expert testimony on energy, economic, and environmental issues in more than one hundred utility regulatory proceedings in twenty six states and two Canadian provinces, in cases in State and Federal Courts, and in proceedings of the Federal Energy Regulatory Committee and the Nuclear Regulatory Commission's Atomic Safety and Licensing Board.

Co-author of more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the National Association of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Heating, Refrigerating, and Air-Conditioning Engineers, American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, the European Federation of Clean Air and Environmental Protection Associations, and others.

TESTIMONY

Nova Scotia Utility and Review Board – April 2011
Testimony on community-based feed-in tarriffs for renewable energy.

United States District Court for the Middle District of Louisiana (Civil Action No. 09-CV-100-RET-CN) United States v. Louisiana Generating LLC – October 2010
Rebuttal report on the use of computer models for electric system planning and projections of generating unit operations, including PROMOD simulation of power system dispatch. Also deposition January 2011.

United States District Court for the Eastern District of Michigan (Case 2:10-cv-13101-BAF-RWS) United States v. DTE Energy Company – June 2010
Declaration on the use of computer models for electric system planning and projections of generating unit operations. Also second declaration November 2010.

United States District Court for the North District of Alabama (Civil Action No. 2:01-CV-00152-VEH) United States v. Alabama Power Company – December 2009
Expert report on use of computer models for electric system planning and projections of generating unit operations. Also rebuttal report in May 2010, and deposition in June 2010.

United States District Court for the Eastern District of Kentucky, Lexington Division (Case 5:05-cv-0075-KSF) United States v. Kentucky Utilities Company – October 2008
Expert report on use of computer models for electric system planning, capital investment planning and economic analysis, and projections of generating unit operations.

Nova Scotia Utility and Review Board – August 2008
Review of rate case issues; power plant depreciation and load forecasting.

Nova Scotia Utility and Review Board – March 2008
Review of Nova Scotia Power Inc.'s demand-side management plan.

Indiana Utility Regulatory Commission (Cause Nos. 43114 and 43114S1) – May 2007
Review of IGCC Plant Proposal by Duke Energy Indiana and Vectren Testimony of Synapse Witnesses. Also cross answering testimony later in the month.

California Public Utilities Commission (Docket No. R.06-02-013) – March 2007
Joint testimony with William Steinhurst and Rick Hornby on electric utility long-term planning and procurement, including procurement strategy, treatment of carbon dioxide emissions, credit and collateral policies, customer risk tolerance, and resource needs.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint testimony with Bob Fagan and David Schlissel on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Indiana Utility Regulatory Commission (Cause Nos. 42861) – October 2005
Vectren (SIGECO) environmental compliance planning, including climate change policy and carbon price forecasting, energy efficiency and renewables as compliance options, and cost recovery issues.

United States District Court for the Eastern District of Kentucky, Lexington Division (Civil Action No.04-34-KSF, United States v. East Kentucky Power Cooperative – September 2005
Expert report on state regulation of electric utilities, use of computer models for system planning, capital investment planning and economic analysis, and projections of generating unit operations.

United States District Court for the Southern District of Indiana (Civil Action No.IP99-1693 C-M/S, United States v. Cinergy – May 2005
Expert report on state regulation of electric utilities, forecasting sales and resource requirements, use of computer models for system planning, capital investment planning and economic analysis, projections of generating unit operations, and the relationship between generator availability and output. Also, rebuttal report in September.

Federal Energy Regulatory Commission (Docket No. EC05-43-000) – April 2005
Market power analysis of the proposed merger of Exelon Corporation and Public Service Enterprise Group Incorporated. (Joint affidavit with David Schlissel.)

Nuclear Regulatory Commission Atomic Safety and Licensing Board (Docket No. 52-007-ESP and ASLBP No. 04-821-01-ESP) – April 2005
Affidavit on the environmental impacts and economic costs of a proposed new nuclear power project and alternatives.

Indiana Utility Regulatory Commission (Cause Nos. 42622 and 42718) – March 2005
Public Service Company of Indiana environmental compliance planning, including cost estimates for emission control technologies, climate change policy and carbon price forecasting, energy efficiency and renewables as compliance options, power plant retirement economics, and cost recovery issues.

National Research Council, Division on Engineering and Physical Sciences, Board on Energy and Environmental Systems (Project No. BEES-J-03-03-A) – March 2005
Alternatives for replacing the generation of the Indian Point Energy Center nuclear facility.

Georgia Public Service Commission (Docket No. 18300-U) – October 2004
Georgia Power Company’s cost of service study, treatment of electrical distribution equipment, and proposed rates for the Metropolitan Atlanta Rapid Transit Authority.

Texas Public Utility Commission (Docket No. 29526) – June 2004
Issues in CenterPoint Energy Houston Electric LLC’s true up filing, including environmental cleanup costs, excess mitigation credits, and construction work in progress. Also rebuttal testimony on June 14.

Texas Public Utility Commission (Docket No. 28818) – April 2004
The Independent Transmission Operator proposal of Energy Gulf States Utilities, Inc. (prefiled testimony adopted by Paul Peterson).

Indiana Utility Regulatory Commission (Cause No. 42359) – August 2003
Public Service Company of Indiana rate making issues including the impact of trackers on risks to shareholders and customers, costs of environmental compliance, treatment of merchant plant investment and risk, and joint dispatch issues.

Nevada Public Utilities Commission (Docket No. 03-1014) – April 2003
Review of Sierra Pacific Power Company’s risk management and procurement of electric power in the wholesale markets.

Nevada Public Utilities Commission (Docket No. 02-11021) – March 2003
Review of Nevada Power Company’s risk management and procurement of electric power in the wholesale markets.

United States District Court for the Southern District of Illinois (Civil Action No. 99-833-MJR, United States v. Illinois Power Company and Dynegy Midwest Generation, Inc.) – August 2003
Testimony at trial on analysis and opinions in rebuttal report dated October 2002 on use of computer models for system planning, projections of generating unit operations, and the relationship between generator availability and output.

State of Vermont, Windham Superior Court (Appeal of USGen New England, Inc. from 2001 Property Valuation by the Town of Rockingham) – September 2002
Electricity market prices and economic valuation of hydroelectric generating plant.

United States District Court for the Middle District of North Carolina (Civil Action No. 1:00 CV 1262, United States v. Duke Energy Corporation) – August 2002
Expert report on use of computer models for system planning, projections of generating unit operations, and the relationship between generator availability and output. (Joint report with Phil Hayet.)

Indiana Utility Regulatory Commission (Cause No. 41746) – July 2002
Reply testimony on a rate case settlement agreement, dealing with issues including NiSource’s financial condition, service quality, environmental commitment, and electric rate impacts.

Connecticut Department of Public Utility Control (Docket No. 00-12-13RE01) – July 2002
The proposed sale of Seabrook Nuclear Station to FPL Energy Seabrook, LLC. Market power issues and market modeling.

United States District Court for the Southern District of Indiana (Civil Action No. IP99-1692-C-M/S, United States v. Southern Indiana Gas and Electric Company) – June 2002
Declaration on confidential business information and competitive harm.

Nevada Public Utilities Commission (Docket No. 02-2002) – April 2002
Review of Sierra Pacific Power Company's risk management and procurement of electric power in the wholesale markets.

Vermont Public Service Board (Docket No. 6596) – March 2002
Used and useful policy issues, electricity market prices, and above market costs of the purchase from Hydro Quebec.

Nevada Public Utilities Commission (Docket No. 01-11029) – February 2002
Review of Nevada Power Company's risk management and procurement of electric power in the wholesale markets.

Vermont Public Service Board (Docket No. 6545) – January 2002
Economic analysis of the proposed sale of Vermont Yankee nuclear plant and an associated Purchased Power Agreement.

New Jersey Board of Public Utilities (Docket No. EM01050308) – September 2001
Analysis of the proposed merger between Conectiv and PEPCo. Also, surrebuttal testimony in November. (Joint testimony with David Schlissel.)

Indiana Utility Regulatory Commission (Cause No. 41954) – June 2001
System planning and joint operation in a partially deregulated context.

State of Vermont, Windham Superior Court (Dockets S 362-9-99 and S372-9-99) – May 2001
Deposition on electricity market prices and economic valuation of hydroelectric generating plant.

Federal Energy Regulatory Commission (Docket No. ER01-200-001) – April 2001
Termination of the Cinergy Operating Agreement, treatment of merger savings, and affiliate relationships. Also cross-answering testimony in April.

New Jersey Board of Public Utilities (Docket No. EM00110870) – April 2001
Analysis of the proposed merger between FirstEnergy and GPU. Also, supplemental testimony in April. (Joint testimony with David Schlissel.)

Vermont Public Service Board (Dockets Nos. 6120 and 6460 – March 2001
Used and useful policy issues, electricity market prices, and above market costs of the purchase from Hydro Quebec. Also, surrebuttal testimony in April.

United States District Court for the Northern District of New York (Civil Action No. 00-CV-1738) – January 2001
Affidavit on the issuance and trading of SO_2 emission allowances under the Title IV of the Clean Air Act, in Clean Air Markets Group v. George E. Pataki et al.

Department of Energy (Docket No. EE-RM-500) – December 2000
Oral testimony on proposed rules for central air conditioner and heat pump energy conservation standards.

Illinois Commerce Commission (Docket No. 00-0361) – July 2000
Review of ComEd's funding for nuclear power plant decommissioning.

California Public Utilities Commission (Rulemaking 99-10-025) – July 2000
Distributed generation and related rate design issues. Also, rebuttal testimony in August.

Massachusetts Department of Environmental Protection – July 2000
Comments on reliability implications of proposed emission standards for power plants.

Arkansas Public Service Commission (Docket No. 00-048-R) – June 2000
Requirements for electricity market power analyses.

United States District Court for the Middle District of North Carolina (1:99CV00033) – March 2000
Expert report on replacement power costs in Carolina Power & Light Company vs. Yuasa Exide, Inc.

Illinois Commerce Commission (Docket No. 99-0115) – September 1999
Review of ComEd's nuclear power plant decommissioning cost estimates.

West Virginia Public Service Commission (Case No. 98-0452-E-GI) – August 1999
AEP and Allegheny Power restructuring, market power, divestiture of generation, electric system market price modeling, statistical analysis of comparable sales, and responsibility for stranded costs and gains.

Mississippi Public Service Commission (Docket No. 96-UA-389) – August 1999
Review of Entergy Mississippi, Inc. and Mississippi Power Company stranded cost filings, divestiture of generation, statistical analysis of comparable sales, responsibility for stranded costs and gains.

Connecticut Department of Public Utility Control (Docket No. 99-03-36) – July 1999
Connecticut Light and Power Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Connecticut Department of Public Utility Control (Docket No. 99-03-35) – July 1999
United Illuminating Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Utah Public Service Commission (Docket No. 98-2035-04) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power.

Washington Utilities and Transportation Commission (Docket No. UE-981627) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power and assessment of whether the merger is in the public interest.

Federal Energy Regulatory Commission (Docket Nos. EC98-40-00, et al.) – April 1999
Horizontal market power and barriers to entry in consideration of the proposed merger of American Electric Power Company and Central and South West Corporation.

Connecticut Department of Public Utility Control (Docket No. 99-03-04) – April 1999
Market power, market prices, and simulation modeling as related to the application of United Illuminating Company for recovery of stranded costs.

Connecticut Department of Public Utility Control (Docket No. 99-02-05) – April 1999
Market power, market prices, and simulation modeling as related to the application of Connecticut Light & Power Company for recovery of stranded costs.

Maryland Public Service Commission (Case No. 8797) – January 1999
Simulation analysis of the ECAR market and projected market prices for electricity for estimation of Potomac Electric Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Case No. 8795) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Delmarva Power and Light Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Cases Nos. 8794 and 8804) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Baltimore Gas and Electric Company's stranded generation costs and unbundled rates.

Vermont Public Service Board (Docket No. 6107) – September 1998
Excess capacity, used & useful, and the economics of Green Mountain Power's purchase from Hydro Quebec.

Mississippi Public Service Commission (Docket No. 96-UA-389) – September 1998
Analyses of market concentration and market power, behavior of affiliated companies, need for an independent system operator.

California Public Utilities Commission (Application No. 97-12-020) – July 1998
Nuclear power plant decommissioning and radioactive waste disposal. Also, rebuttal testimony in August.

Federal Energy Regulatory Commission (Docket No. EC97-46-000) – June 1998
Affidavit on market power implications of the proposed merger between Allegheny Power System and Duquesne Light Company.

New Jersey Board of Public Utilities (Docket Nos. EX4120585Y, EO97070460, and EO97070463) – March 1998
Economic and environmental benefits of energy efficiency, including estimation of marginal air emissions from the PJM System. (Joint testimony with Nathanael Greene, Edward Smeloff, and Thomas Bourgeois.)

Vermont Public Service Board (Docket No. 6018) – February 1998
Excess capacity and the economics of Central Vermont Public Service Company's purchase from Hydro Quebec.

Public Service Commission of Maryland (Case No. 8774) – February 1998
Market power implications of the APS-DQE merger.

Federal Energy Regulatory Commission (Docket Nos. OA97-237-000 and ER97-1079-000) – January 1998
Market power in New England electricity markets.

British Columbia Utilities Commission – November 1997
British Columbia Hydro and Power Authority Wholesale Transmission Services Application.

Pennsylvania Public Utility Commission (Docket R-00973981) – November 1997
West Penn Power Company Restructuring Plan. Environmental disclosure, consumer education, and allocation of default customers.

Pennsylvania Public Utility Commission (Docket R-00974104) – November 1997
Duquesne Light Company Restructuring Plan. Environmental disclosure, consumer education, nuclear decommissioning, and allocation of default customers. Also surrebuttal testimony in December 1997.

Mississippi Public Service Commission (Docket No. 97-UA-496) – November 1997
Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing Construction of a Generating Plant in Jackson County.

Pennsylvania Public Utility Commission (Docket Nos. R-00973953 and P-00971265) – November 1997
Application of PECO Energy Company for approval of its restructuring plan and petition on Enron Energy Services Power, Inc. for approval of an electric competition and customer choice plan. Allocation of default customers.

Vermont Public Service Board (Docket No. 5983) – October 1997
Excess capacity and the economics of Green Mountain Power Company's purchase from Hydro Quebec. Also rebuttal testimony in December 1997 and supplemental rebuttal testimony in January 1998.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – September 1997
Joint petition for partial settlement of PECO Energy Company's proposed restructuring plan and application for a qualified rate order. Environmental disclosure, nuclear decommissioning and spent fuel.

Pennsylvania Public Utility Commission (Docket No. R-00974009) – September 1997
Pennsylvania Electric Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Pennsylvania Public Utility Commission (Docket No. R-00974008) – September 1997
Metropolitan Edison Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Indiana Legislature, Regulatory Flexibility Committee -- September 23, 1997.
Testimony on "Electric Industry Restructuring To Benefit Consumers and the Environment: Stranded Costs, Nuclear Issues, and Air Emissions."

Pennsylvania Public Utility Commission (Docket No. R-00973954) – June 1997
Pennsylvania Power & Light Company's Restructuring Plan. Environmental disclosure, customer education, PJM market structure, nuclear decommissioning and spent fuel, rate design for stranded cost recovery. Also, surrebuttal testimony in August.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – June 1997
PECO Energy Company's Restructuring Plan. Environmental disclosure, PJM market structure, nuclear decommissioning and spent fuel.

New York Public Service Commission (Case 96-E-0897) -- April 1997
Consolidated Edison Company's Plans for Electric Rate Restructuring. Analysis of market power in the New York City load pocket.

Pennsylvania Public Utility Commission (Docket No. R-00973877) -- February 1997
Application of PECO Energy Company for Issuance of a Qualified Rate Order. Nuclear power plant decommissioning costs, stranded cost recovery, and securitization.

New Hampshire Public Utilities Commission (DR 96-150) -- November 1996
Electric industry restructuring, including stranded costs, industry structure, market power, and nuclear issues.

Massachusetts Department of Public Utilities (96-100) -- July 1996
Nuclear plant stranded costs and decommissioning.

Vermont Public Service Board (5854) – July 1996
Electric industry restructuring, including stranded costs, industry structure, and environmental protection.

Ontario Energy Board (H.R. 23) -- June 1995
Electricity rate options (joint evidence with John Stutz).

Pennsylvania Public Utility Commission (R-00943271) -- April 1995
Discount rates and system benefits charge.

Colorado Public Utilities Commission (94A-516A) – January 1995
Construction of new generating resources.

Public Service Commission of Nevada (94-9002) – November 1994
Environmental and health impacts of a proposed power plant.

Nuclear Decommissioning Finance Committee of New Hampshire (93-001) – September 1994
Seabrook decommissioning cost, spent fuel storage, and cost collection methodology (joint testimony with William Dougherty).

Public Service Commission of Wisconsin (6630-CE-197 and 6630-CE-209) – September 1994
Point Beach externalities, economics, spent fuel storage, and aging (joint testimony with William Dougherty).

British Columbia Utilities Commission – August 1994
Greenhouse gas emissions and environmental externalities policy

Public Service Commission of Wisconsin (05-EI-14) – February 1994
Cost of decommissioning Point Beach and Kewaunee nuclear power plants. Also, rebuttal and surrebuttal testimony in February.

Delaware Public Service Commission (91-39) – September 1992
Nuclear and fossil power plant performance targets.

Massachusetts Department of Public Utilities (91-131) – December 1991
Internalization of environmental externalities, greenhouse gas valuation and policy.

Massachusetts Department of Public Utilities (91-131) – October 1991
Environmental externalities valuation, emissions effects and global warming.

Massachusetts Department of Public Utilities ((89-141, 90-73, 90-141, 90-194 and 90-270) **–**
December 1990
The incorporation of environmental externalities in specific utility RFPs.

Massachusetts Department of Public Utilities (90-55) – June 1990
Costs and benefits of high-efficiency gas heating equipment.

Massachusetts Department of Public Utilities (86-36-G and 89-239) – March 1990
Environmental externalities of electric resources.

Florida Public Service Commission (890973-E1) – January 1990
Integrated energy planning, power plant emissions, and nuclear plant performance.

Pennsylvania Public Utilities Commission (R-891364) – October 1989
Generating capacity requirements of the Philadelphia Electric Company and the Pennsylvania-New Jersey-Maryland Interconnection.

Maryland Public Service Commission (8199) – October 1989
Performance standards for coal, oil, and nuclear power plants.

Michigan Public Service Commission (U-9172) – April 1989
Economic analysis of the Palisades Power Purchase Agreement. Ratepayer impacts, incentives, and implications for plant operation and decommissioning.

Pennsylvania Public Utility Commission (P-870216, P-880283, P-880284, and P-880286) – March 1989
Allegheny Power System planning and avoided costs.

Michigan Public Service Commission (U-8880) – February 1988
Detroit Edison Company power supply costs, economics of Fermi “buy-back” purchase, nuclear fuel expense, oil costs, and power transactions.

Michigan Public Service Commission (U-8866) – December 1987
Consumers Power Company power supply costs, including projections of oil prices and purchased power costs.

Pennsylvania Public Utility Commission (R-850220) – September 1987
Economic analysis of West Penn Power Company’s participation in the Bath County Pumped Storage Project, and Allegheny Power System capacity reserve requirements. Also, surrebuttal testimony in October.

Arizona Corporation Commission (U-1345-85-367) – February 1987
Palo Verde decommissioning cost.

Michigan Public Service Commission (U-8545) – December 1986
Consumers Power Company power costs, projected cost of oil and purchased power, economic evaluation of the Big Rock Point nuclear unit.

Public Service Commission of Indiana (38045) – November 1986
Northern Indiana Public Service Company system reliability and excess capacity.

California Public Utility Commission (84-06-014 and 85-08-025) – July 1986
Diablo Canyon decommissioning cost and collection issues.

Michigan Public Service Commission (U-8042R) – June 1986
Review of Consumers Power Company system operations during 1985 and economic evaluation of the Big Rock Point nuclear unit.

Michigan Public Service Commission (U-8291) – April 1986
Detroit Edison Company power supply costs, application of a multi-area dispatch model.

Michigan Public Service Commission (U-8286) – February 1986
Consumers Power Company power supply costs, application of a multi-area dispatch model.

Maine Public Service Commission (85-132) – January 1986
Standard and long term rates for cogeneration and small power production. Surrebuttal testimony in February.

Arkansas Public Service Commission (84-249-U) – June 1985
Impact of the Grand Gulf nuclear unit upon Arkansas Power and Light Company and Middle South Utilities electricity production costs.

Kentucky Public Service Commission (8666) – February 1984
Production costing modeling issues.

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Avoided Energy Supply Costs in New England: 2011 Report, prepared for Avoided-Energy-Supply-Component (AESC) Study Group by Rick Hornby, Paul Chernick, Dr. Carl Swanson, Dr. David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald. July 21, 2011.

Equipment Price Forecasting in Energy Conservation Standards Analysis Comments, submitted to the US Department of Energy on behalf of the Natural Resources Defense Council and the Appliance Standards Awareness Project. By Tim Woolf, Vladlena Sabodash, and Bruce Biewald. March 24, 2011.

2011 Carbon Dioxide Price Forecast. By Lucy Johnston, Ezra Hausman, Bruce Biewald, Rachel Wilson, and David White. February 11, 2011.

Benefits of Beyond BAU: Human, Social, and Environmental Damages Avoided through the Retirement of the U.S. Coal Fleet, prepared for Civil Society Institute by Jeremy Fisher, Rachel Wilson, Nicole Hughes, Matthew Wittenstein, and Bruce Biewald. January 25, 2011.

Electricity Energy Efficiency Benefits of RGGI Proceeds: An Initial Analysis, prepared for Regulatory Assistance Project by Max Chang, David White, Lucy Johnston, and Bruce Biewald. October 5, 2010.

Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S., prepared for Civil Society Institute by Geoffrey Keith, Bruce Biewald, Kenji Takahashi, Alice Napoleon, Nicole Hughes, Lauri Mancinelli, and Erin Brandt. May 11, 2010.

Co-Benefits of Energy Efficiency and Renewable Energy in Utah, prepared for State of Utah Energy Office by Jeremy Fisher, Rachel Wilson, Maximilian Chang, Jennifer Kallay, and Chris James of Synapse, and Jon Levy, Yurika Nishioka, and Paul Kirshen. March 24, 2010.

Avoided Energy Supply Costs in New England: 2009 Report, prepared for AESC/ Massachusetts Avoided Energy Supply Components Study Group by Rick Hornby, David White, Bruce Biewald, Chris James, Ben Warfield, and Max Chang of Synapse, and Paul Chernick, Carl Swanson, Ian Goodman, Bob Grace, and Jason Gifford, August 21, 2009.

Productive and Unproductive Costs of CO2 Cap-and-Trade: Impacts on Electricity Consumers and Producers, prepared for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association by Ezra Hausman, Jeremy Fisher, Lauri Mancinelli, and Bruce Biewald, July 15, 2009.

Incorporating Carbon Dioxide Emissions Reductions in Benefit Calculations for Energy Efficiency: Comments on the Department of Energy's Methodology for Analysis of the Proposed Lighting Standard, prepared for New York State Attorney General by Bruce Biewald, David White, Jeremy Fisher, Max Chang, and Lucy Johnston, May 13, 2009.

Cost and Benefits of Electric Utility Energy Efficiency in Massachusetts, prepared for the Northeast Energy Efficiency Council by Doug Hurley, Kenji Takahashi, Bruce Biewald, Jennifer Kallay, and Robin Maslowski, August 1, 2008.

Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation, prepared for U.S. Environmental Protection Agency by Ezra Hausman, Jeremy Fisher, and Bruce Biewald, July 23, 2008.

Don't Get Burned: The Risks of Investing in New Coal-Fired Generating Facilities, prepared for Interfaith Center on Corporate Responsibility by David Schlissel, Lucy Johnston, Jennifer Kallay, Christopher James, Anna Sommer, Bruce Biewald, Ezra Hausman, and Allison Smith, February 26, 2008.

Tufts Cove Waste Heat Recovery Project, prepared for the Nova Scotia Utility and Review Board by Bruce Biewald, Bill Powers, and Ben Warfield, December 4, 2007 and revised August 4, 2008.

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The Deerfield Wind Project – Assessment of the Need for Power and the Economic and Environmental Attributes of the Project, prepared for PPM Energy by Ezra Hausman, Bruce Biewald, and Kenji Takahashi, August 1, 2006.

Portfolio Management: Tools and Practices for Regulators, prepared for the National Association of Regulatory Utility Commissioners by William Steinhurst, David White, Rick Hornby, Alice Napoleon, Amy Roschelle, and Bruce Biewald, October, 2006.

Incorporating Energy Efficiency into the ISO New England Forward Capacity Market: Ensuring the Capacity Market Properly Values Energy Efficiency Resources, prepared for Conservation Services Group by Paul Peterson, Doug Hurley, Tim Woolf, and Bruce Biewald, June 5, 2006.

Ensuring Delaware's Energy Future: A Response to Executive Order Number 82, prepared for the Delaware Public Service Commission Staff by the Delaware Cabinet Committee on Energy with technical assistance from Synapse Energy Economics, March 8, 2006.

The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis, prepared for the Connecticut Fund for the Environment and Save The Sound by Ezra Hausman, Bruce Biewald, Kenji Takahashi, and David Schlissel, January 22, 2007.

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Considering Climate Change in Electric Resource Planning: Zero is the Wrong Value, by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald, Rev 3, September 30, 2005.

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“Demand Response in Electricity Markets,” presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting in Santa Fe, New Mexico, June 18, 2001.

Presentation on “Repowering the Midwest: The Clean Energy Development Plan for the Heartland,” at the National Wind Coordinating Committee Upper Midwest Transmission Workshop, Minneapolis, Minnesota, May 1, 2001.

“Observations on New England’s Electricity Markets,” National Regulatory Research Institute Market Power Conference, Columbus, Ohio, April 10, 2001.

Presentation on “Derailing Coal: The Economics of Coal-Fired Electricity Generation in the U.S.,” Tax Shift Strategy Meeting, Washington, D.C., December 2, 2000.

Presentation on “Repowering the Midwest: A Clean Energy Development Plan for the Heartland,” presentation with Howard Learner at the National Association of Regulatory Utility Commissioners Annual Meeting, San Diego, California, November 14, 2000.

Presentation on “Electricity in New England: Market Imperfections of Failure?” at National Association of State Utility Consumer Advocates Annual Meeting, San Diego, California, November 13, 2000.

Presentation on “How Green is Green? Verifying Energy Advertising Claims,” at the New England Conference of Public Utility Commissioners Symposium, Bretton Woods, New Hampshire, May 25, 1999.

Presentation on “Consumer Perspectives on Market Power – Case Studies from New England, New York, PJM, and Mississippi,” IBC Conference on Market Power, Washington DC, May 24, 1999.

Presentation on “Grandfathering and Environmental Comparability,” at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on “Tracking Electricity in the New England Market,” at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on “Tracking Electricity in the New England Electricity Market,” at the National Council on Competition and the Electricity Industry National Executive Dialogue on Customers’ Right to Know, Chicago, May 13, 1998.

Presentation on “Comparable Environmental Regulations in a Restructured Electricity Industry: The Grandfathering Effect,” National Association of Regulatory Utility Commissioners meeting in Washington, D.C., March 1, 1998.

Presentation on “Market Power in Electricity Generation,” National Consumer Law Center Conference, Washington, D.C., February 9, 1998.

Presentation on “Electricity Market Power in New England,” Massachusetts Electric Industry Restructuring Roundtable, Boston, December 15, 1997.

Presentation on wind power development and air quality, National Wind Coordinating Committee New England Wind Issues Forum, Boston, November 7, 1997.

Invited speaker on market power, National Association of State Utility Consumer Advocates meeting in Boston, November 12, 1997.

Presentation on “Distortions to Future and Current Competitive Electric Energy Markets Due to Grandfathering Environmental Regulations of Electric Power Plants,” National Association of Regulatory Utility Commissioners meeting in Boston, November 9, 1997.

Presentation on “Electric Industry Restructuring as if the Environment Mattered,” Boston Area Solar Energy Association, October 9, 1997.

Invited speaker on “Modeling Market Power in Electricity Generation,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 22, 1997.

Presentation on “Performance-Based Regulation in a Restructured Electric Industry,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 20, 1997.

Presentation on “State Initiatives and Regional Issues,” New England Governors’ Conference Workshop on Restructuring and Environmentally Sustainable Technologies, Warwick, Rhode Island, March 25, 1997.

Invited speaker on stranded costs, National Association of State Utility Consumer Advocates meeting in San Francisco, November 1996.

Presentation on “Nuclear Power Plant Decommissioning Costs and Electricity Restructuring,” Nuclear Decommissioning Trusts conference, New York City, November 18, 1996.

Invited speaker on stranded costs, Indiana Utilities Regulatory Commission Forum, Indianapolis, November 1, 1996.

Presentation on “Electric Industry Restructuring and the Environment,” at the Indiana Energy Conference, Indianapolis, Indiana, October 10, 1996.

Presentation on "Small Customers in a Restructured Electricity Industry: Transaction Costs, Advanced Metering Technologies and Aggregation Options" to the Consumers' Energy Conference, South Portland, Maine, July 1996.

Presentation on "Electric Generation Market Power in New England" to New England Conference of Public Utility Commissioners, Manchester Village, Vermont, May 1996.

Presentation on "Advanced Metering for Residential Customers on Electricity Restructuring" to National Consumer Law Center's 10th Annual Conference in Washington, DC, February 1996.

Presentations on "Market Power," "Environmental Aspects of Restructuring" and "Market Access for Small Customers" to Vermont Public Service Board workshops on electricity restructuring, January and February 1996.

Presentation on "Environmental Impacts of Energy: Sustainability and Social Costing" to British Columbia Utilities Commission Workshop, Vancouver, BC, March 1995.

Presentation on "Competition and Economic Efficiency" to the National Council on Competition and the Electric Industry, December 1995.

Presentation on "Compliance Planning Under Regulatory Uncertainty," to EPA "Opportunities Conference: Energy Efficiency and Renewable Energy," Washington, DC, June 1993.

Presentation on "Energy and Sustainability" to Hydro-Quebec Conference, Hampshire College, Amherst, Massachusetts, April 1993.

Invited Speaker on environmental externalities, ASME "ECO World" conference in Washington, DC, June 1992.

Invited Speaker, Association of Energy Engineers, Boston, Massachusetts, February 1992.

Presentation of Acid Rain Abatement Optimization Model to the Swedish Environmental Protection Agency, Solna, Sweden, November 1991.

Presentation on Integrated Resource Planning to Boston Gas Company, July 1990.

Training on Methods for Calculating Electric System Avoided Costs, provided to energy planners and policy makers from five Southeast Asian countries sponsored by U.S. Agency for International Development and administered by the Institute of International Education, May 1990.

Invited Speaker, National Association of State Utility Consumer Advocates (NASUCA) Mid-Year Meeting, Annapolis, Maryland, and June 1988.

Invited Speaker, Conference on New Developments in Nuclear Decommissioning Costs and Funding Methods, sponsored by the Northeast Center for Professional Education, Washington, DC, April 1988.

APPENDIX B

ELECTRIC UTILITY SYSTEM RELIABILITY ANALYSIS
SEPTEMBER 1988

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ELECTRIC UTILITY SYSTEM RELIABILITY ANALYSIS: DETERMINING THE NEED FOR GENERATING CAPACITY

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Introduction

Recently, some electric utility systems have increased their reserve margin requirements, with direct and significant implications for capacity planning and electricity rates. The additional capacity required to satisfy the increased reserve targets can be costly, as can the impacts of capacity shortages. Therefore, reserve planning should be approached with state-of-the-art analyses and, just as importantly, a full knowledge of the capabilities and weaknesses of the models and techniques used in these analyses.

In planning future capacity requirements, electric utilities commonly use the reserve margin as a measure of capacity needs. Reserve margin standards have also been applied by regulators in making utility ratebase disallowances for excess capacity. However, the reserve margin is not an end in itself -- but is only a rough indicator of the reliability of an electric utility system. Moreover, a single change to the system, such as the addition of a nuclear generating unit, can change the reserve margin requirement of a utility by several percentage points. Thus, it is important to assess reliability more directly, by calculating "loss of load probabilities" (and other measures of the ability to serve load) using computerized models of system reliability.

Probabilistic "reliability models," while essential to a good capacity planning process, require simplifying assumptions that should be made judiciously. We have found that appropriate use of plant performance data, and proper modelling of partial generating unit outages, system emergency operating procedures, and interconnection capability are essential to an accurate assessment of system reliability.

Electric System Reserve Margins

An electric utility system's reserve margin is usually defined as the percentage by which the system's firm resources exceed peak hour firm customer demand. Typically the full seasonal capacity rating of all generating units is included, even for units with scheduled or unscheduled outages at the time of peak demand. The reason for this is that scheduled outages can generally be planned for off-peak seasons as necessary, while unscheduled outages are the principal events for which reserves are provided in the first place.

Firm purchases from other utility companies are also generally included as capacity resources in establishing a reserve margin. The availability of non-firm purchases for short-term emergency or economy power support, while not traditionally counted as a part of reserves, also enhance system reliability and, thereby, will reduce the reserves necessary to achieve a given level of reliability. Thus the reserve margin and transmission interconnections enable a utility to continue to satisfy demand when some of its generating units suffer outages. Moreover, an electric utility has a variety of additional options and procedures available to it to enable it to maintain service to its customers under adverse circumstances.

Maintaining a particular reserve margin is not an end in itself. The objective is a reasonable level of system reliability and the reserve margin, if developed properly, will correlate with an acceptable reliability level.

Capacity Margins

Recently, a number of utilities have begun using capacity margin to express the level of system reserve capacity, replacing the more conventional reserve margin measure. There is no fundamental difference between the two. Reserve margin is defined as follows:

$$\text{Reserve Margin} = \frac{(\text{Firm Capacity} - \text{Firm Load})}{\text{Firm Load}} \times 100$$

And capacity margin, also a simple function of system load and capacity, is defined as follows:

$$\text{Capacity Margin} = \frac{(\text{Firm Capacity} - \text{Firm Load})}{\text{Firm Capacity}} \times 100$$

The two measures are related thus:

$$\text{Capacity Margin} = \frac{\text{Reserve Margin}}{1 + \text{Reserve Margin}}$$

$$\text{Reserve Margin} = \frac{\text{Capacity Margin}}{1 - \text{Capacity Margin}}$$

Thus, a reserve margin of 20 percent is equivalent to a capacity margin of 16.7 percent. While either measure will suffice, the shift from reserve margin to capacity margin can cause some confusion and misunderstanding, especially under conditions of excess capacity. For example, a reserve margin of 40 percent, when reported as a capacity margin, translates to only 28 percent, and consequently may appear less problematical.

Measures of Reliability

Generating system reliability is often quantified in terms of the probability that demand is expected to exceed available firm resources. The loss of load probability, or LOLP, is commonly expressed as the amount of time (for example, days) that demand will exceed resources during a ten-year period on an average or probabilistic basis, given the particular load, resource and interconnection characteristics of the utility system. A more precise term for what is usually referred to as LOLP is loss of load expectation (LOLE), the expected value for the number of occasions (e.g., days) on which the system will experience resource deficiency leading to loss of load. Here, however, we will use the common (although imprecise) terminology.

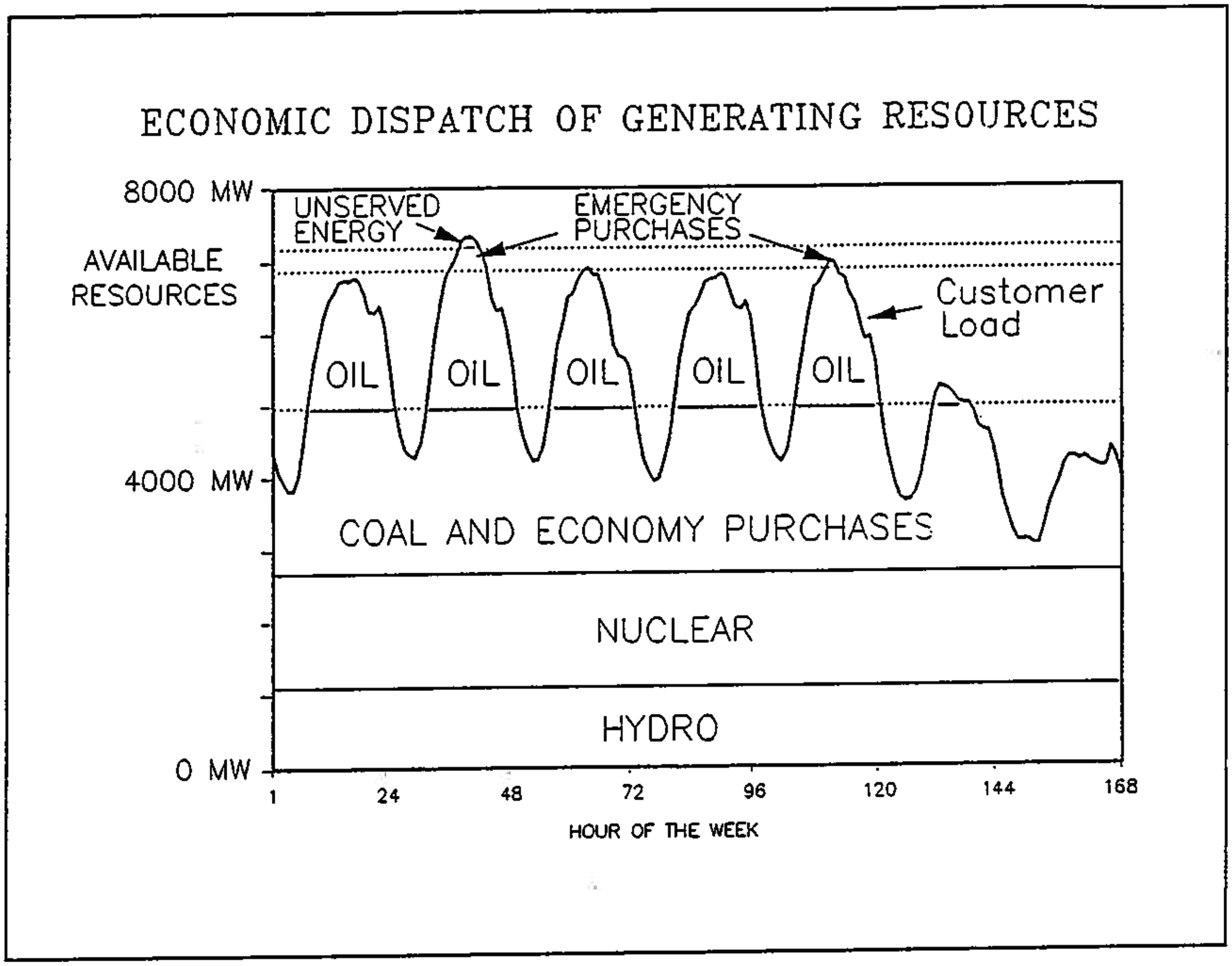
In assessing the LOLP of a system, the generating resources and interconnections must be represented properly. Moreover, the various operating procedures available to the utility to exceed or supplement its generating resources, in order to avoid actual load loss, must be taken into account.

It is important to note that the basic number-of-days-in-ten-years definition of loss of load probability does not explicitly address the magnitude or duration of the expected losses. Losses of load of just a few megawatts for short durations on average have different impacts than do losses of larger magnitude and longer duration. Other measures which describe the duration and magnitude of outages are occasionally used in analyses of electric system reliability.

One measure of system reliability that conveys additional information is "expected energy unserved." This measures the amount of energy demanded but not delivered to customers owing to plant outages. If the LOLP and the expected energy unserved have both been calculated, then the average magnitude of lost load (in MW) can be calculated from these two results.

Figure 1 shows a simplified dispatch of an electric utility system for one week. The heavy line representing customer loads can be seen fluctuating on a daily cycle. One loss of load event is depicted, occurring on the second daily peak of the week.

FIGURE 1



The area above the available capacity (including emergency purchases) and below the customer load curve corresponds with the amount of "expected energy unserved." The horizontal length of the line under the unserved energy represents the duration of the loss of load event. Note that loss of load events can occur at load levels below the peak load, as a result of generating unit outages.

Emergency purchases can serve to decrease the magnitude and duration of a loss of load event, as seen in the second daily peak of the example in Figure 1. They can also help to avoid a loss of load event entirely, as on the fifth daily peak of the example. Note that other emergency operating procedures can likewise reduce the frequency, magnitude, and duration of load loss. These emergency operating procedures can also include voltage reduction, direct load control, customer appeals, and the use of auxiliary generating resources.

Most commonly, reliability criteria are defined in terms of a specified LOLP. Once an LOLP criterion is established, the reserve margin necessary to meet this criterion can be determined by accurately modelling the system. It should be emphasized that the LOLP estimates are theoretical and in practice tend to significantly overestimate actual generation-related outages, as discussed in more detail later.

A loss of load probability of one day in ten years is the criterion most widely used by utilities in the United States. There are, however, significant differences in approaches to modelling interconnections, generator outage rates and various other relevant phenomena in calculating the loss of load probability for a particular system. These differences in modelling approach result in differences in the level of reserves that this criterion implies for a particular system. Data from the nine North American Electric Reliability Council regions indicates that all five of the regional councils that have an LOLP criterion use one day in ten years.

Reserve Margins Used for Reliability Purposes

The usual assumption is that for a large, well interconnected system, a 15-20 percent reserve margin is adequate for reliability. Reserve margins above 20 percent could be required under certain circumstances, especially if the system relies heavily upon large nuclear units which have high outage rates, and also if the system has a very high load factor. However, with sufficient interconnection even heavily nuclear utilities may not need high reserves. One such utility, Commonwealth Edison, plans its system on the basis of a 15 percent reserve margin for reliability purposes.

The principal reason that some utility system reserve margin planning targets have increased to 20 percent and above over the past two decades is the increasing reliance on larger units, particularly nuclear units, which tend to be less reliable than smaller, especially non-nuclear, units. Moreover, it is important to distinguish between the minimum reserves required for reliability purposes, primarily in the 15 to 20 percent range, and planning reserve levels used by some utilities. Often utilities plan for higher levels of reserves than are needed for reliability, in order to achieve overall long-run economics, e.g., by displacing high cost fuels with low cost fuels.

Reliability Criteria Used by the NERC Regional Councils

The North American Electric Reliability Council (NERC) was formed by the electric utility industry "to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America."[1] NERC is divided into nine "regional councils" or regions, which collect data from the utility systems within the region, and perform assessments of the adequacy of the current and projected generating capacity. Most of the regions develop reserve or reliability criteria with which the individual utility systems within the region are expected to follow. In some cases, compliance with the regional criterion is a contractual obligation which specifies penalties for systems with less than the required reserves.

In Table 1, the reliability criteria of the NERC regions are listed. The requirements are expressed in various ways. Each of the five regions that uses an LOLP criterion in assessing the adequacy of power supplies has adopted the standard value of one-day-in-ten-years. These regions are MAAC, MAIN, NPCC, SPP AND WSCC. Five of the regions specify criteria in terms of "reserve margins." These are "ERCOT, MAAC, MAIN, MAPP, and SPP. The reserve margins specified for these regions range from 15 percent to 24 percent.

Diversity of loads allows the reserve margin requirements for individual systems within these regions to be lower than for the region as a whole. The reserve margin requirements specified for individual systems range from 15 percent to 22 percent, with lower reserve margins allowed for hydro-based systems.

The Southeastern Electric Reliability Council (SERC) region is large and diverse. The individual systems in this region are responsible for establishing and providing the levels of generating reserves needed.

The East Central Area Reliability Coordination Agreement (ECAR) uses a criterion expressed in terms of dependence upon supplemental capacity resources (DSCR). With the DSCR methodology, interties with other systems are not represented. No distinction is made between customer demand that would be unserved, and demand that would be served by tie-line support from other systems. With this methodology the criterion is generally (and appropriately) set well above the usual LOLP criteria of 1 day in 10 years, since a 1 day in 10 years LOLP can be satisfied with a much larger level of reliance on outside sources of power. ECAR considers DSCR values in the range of 1 day per year to 10 days per year to be acceptable. The results of ECAR's 1986 appraisal shows that with a generating unit availability rate at the average for the last five years, DSCR requirements is satisfied at a reserve margin of about 19 percent.[2]

Individual utilities within the ECAR region can set their own DSCR criteria much higher than ECAR's, but consistent with ECAR's criterion, owing to the diversity of loads within ECAR and the availability of mutual support amongst its member systems.

Table 1

Reliability Criteria Used by the NERC Regions

Reliability Council	Reserve or Reliability Criterion for Region	Reserve or Reliability Criterion Determined by Region for Individual Systems or Groups of Systems
East Central Area Reliability Agreement (ECAR)	1 to 10 days/year dependence upon supplemental capacity reserves (DSCR)	None
Electric Reliability Council of Texas (ERCOT)	15% reserve margin	15% reserve margin
Mid-Atlantic Area Council (MAAC)	1 day in 10 years LOLP	22% reserve margin
Mid-American Interpool Network (MAIN)	15% to 22% reserve margin to meet 1 day in 10 years	15% to 20% reserve margin
Mid-continent Area Power Pool (MAPP)	21%-24% reserve margin	15% reserve margin (10% for hydro systems)
Northeast Power Coordinating Council (NPCC)	1 day in 10 years LOLP for each subregion	Each subregion has its own method
Southeastern Electric Reliability Council (SERC)	Each system has its own criterion	None
Southwest Power Pool (SPP)	10% reserve margin	18% reserve margin (10% for hydro systems) or 1 day in 10 years LOLP (with 15% floor)
Western Systems Coordinating Council (WSCC)	None	Each system should meet at least one of several criteria, one of which is an LOLP of one day in ten years.

Source: An Overview of Reliability Criteria Among the Regional Councils of the North American Electric Reliability Council (NERC).

Reliability Criteria Used by Selected Utility Systems

Individual utility systems within the NERC regions sometimes develop their own criteria to use for planning purposes. Also, power pools generally set up reserve margin criteria for planning which are sometimes also used for allocating the costs of capacity among the member companies.

The New England Power Pool (NEPOOL), which operates within the NPCC region, currently plans for a reserve margin of about 20 percent, for the period after its two nuclear units have passed their immature stage. This pool uses its reserve margin requirement as a basis for "capacity equalization" payments amongst its members.

Another large pool, the American Electric Power (AEP) system, a member of the ECAR region, uses a DSCR criterion for reliability analysis. DSCR values in the range of 50 to 90 days per year have been considered adequate by AEP for its system. Information presented in AEP's 1985 Generating Capacity Margins Appraisal[3] indicates that even the more stringent end of the DSCR range (50 days) is satisfied at a reserve margin of about 16 percent.

Commonwealth Edison Co. is a well-interconnected utility system in the MAIN region which relies upon nuclear power plants for a large fraction of system capacity (approximately 40 percent currently, with 3 nuclear plants under construction.) The reserve margin used by Commonwealth Edison Co. planners is 15 percent.

The Public Service Company of Colorado, an electric utility in the WSCC region, uses a reserve margin criterion of 11 percent plus a "severe weather component" designed to allow for uncertainty in weather sensitive load. The two components, together, average 14.6 percent for the forecast period.[4]

The New York Power Pool (NYPP) a member of the NPCC region, used an LOLP criterion of one day in ten years, until 1979, at which point the criterion was re-evaluated. The revised NYPP criterion is one disconnection every ten years after accounting for all emergency operating procedures such as voltage reductions and appeals to customers to voluntarily curtail demand.[5] For the NYPP system, this criterion corresponds with a 'conventional' LOLP criterion (i.e., without accounting for emergency operating procedures) of five days in ten years. The expected number of voltage reductions under the new criterion is four per year. Thus, NYPP planners have explicitly recognized the utility's ability to introduce emergency procedures to avoid actual load loss. Assuming capacity transfer capability from other interconnected utility systems, the corresponding reserve margin derived for the New York Power Pool is 22 percent. This implies a reserve margin of only 18 percent for the individual companies within the pool, owing to the diversity of loads.

General Characteristics of Utility Systems Which Affect Reliability and Reserves Requirements

The major characteristics of a utility system which affect the reliability/reserves relationship are:

(1) Load shape

(2) Forced outage rates of generating units

(3) Maintenance outage requirements for generating units

(4) The number and size of generating units

(5) Transmission interties with neighboring utilities

(6) Availability and effectiveness of intervention procedures

A lower system load factor will tend to increase reliability and decrease the reserve margin necessary to meet a given reliability criterion. Lower load factors generally permit more opportunities (during seasonal low load periods) for maintenance, without jeopardizing reliability during those periods, thus allowing greater resources to be available during high load periods.

There are, however, certain economic reasons to prefer high load factors. Thus, it may be that optimum deployment of resources for reliability is sacrificed in order to achieve operating economies. Of course, this would mean that those operating economies would be greater than the additional resource costs (or reliability impacts) incurred. It should be noted that load factor itself is just an aggregate measure of load shape, and that the detailed monthly shapes can have an impact upon system reliability as well.

Most directly, lower forced outage rates for generating units will result in greater system reliability and, consequently, a lower reserve margin to meet a given reliability criterion. Similarly, units which have lower and more flexible maintenance requirements will contribute to greater system reliability and lower reserve margin requirements. Larger (especially nuclear) units typically have higher than average outage rates. They also have less flexibility in maintenance scheduling, start-up and load following. Peaking and hydro resources generally have low forced outage rates and great flexibility to meet rapidly changing loads.

Smaller sized generating units will result in relatively greater reliability and lower reserve margin requirements. For example, consider a system comprised of only two units of 250 MW, each with ten percent forced outage rate. This system will have only a one percent chance of experiencing a 500 MW outage, because for this to occur both units must be forced out of service simultaneously. In contrast, another system with a single 500 MW unit (with the same 10 percent forced outage rate) will have a ten percent chance of experiencing a 500 MW capacity outage. Moreover, as noted above, smaller units tend to have lower forced outage rates.

A utility system which has substantial interconnections with neighboring systems can take advantage of diversity of loads and resources to obtain system support when needed, for those few hours when internal resources are insufficient to meet load. Greater interconnection will result in greater reliability and criterion. Where systems are very well interconnected they should generally be treated as one entity for purposes of reliability analysis.

Finally, utility systems can use a number of options to avoid outages when peak load exceeds the generating resources that are available under normal conditions. These include shedding interruptible loads, re-scheduling maintenance, use of emergency generator ratings, voltage reductions and, ultimately, appeals to customers to reduce usage. The availability and effectiveness of these measures varies from system to system.

Impact of Generating Unit Additions

One of the reasons that it is important to conduct reliability analyses, rather than to simply use a single reserve margin for system planning purposes, is that the relationship between reliability and reserve margin can change. In particular, an abrupt change can occur when a new generating unit is brought on-line.

Recently, some electric utilities have increased their target reserve margins, coinciding with the commercial operation of large new units. In particular, nuclear generating units can have a detrimental impact upon system reliability, increasing reserve margin requirements by several percentage points. There are several characteristics of the new unit that can be important, including its size and its availability.

ESRG has found that for several systems the addition of a new nuclear unit increased the system's reserve margin requirement by four percentage points. That is, in order to maintain the same level of reliability after the nuclear addition began operating, the systems required roughly four percentage points more generating capacity. This additional need occurs for two reasons. First, the outage rate of a large nuclear unit is generally higher than the average for the previously existing system plants. Second, the size of a new nuclear unit is generally much greater than the average size of the existing plants.

Thus, prior to the addition of a major resource, an electric system should evaluate the reliability impacts of the addition. This is particularly important if the characteristics of the resource addition are unlike the previously existing capacity mix.

For reserve margin requirements to change by several percentage points is not unusual, particularly with the addition of a nuclear generating capacity.

Reliability Modelling

Computer models are used to calculate the reliability indices of electric utility systems, including LOLP, DSCR, and unserved energy. The input data requirements and appropriate methodological approach depend upon the question to be answered.

Sometimes these reliability models are used as a check on the adequacy of reliability over some future planning period. The ECAR and AEP reports referred to above are examples of this type of study. System characteristics are projected and reliability indices are calculated. If the calculated indices compare favorably with pre-determined criteria, then the system plan is judged to be adequate.

Another very common application of reliability modelling is in determining the reserve margin required for a particular system to satisfy a particular reliability criterion. Some of the NERC regions perform such studies in arriving at the system reserve margins which will provide LOLP at a level of one day in ten years.

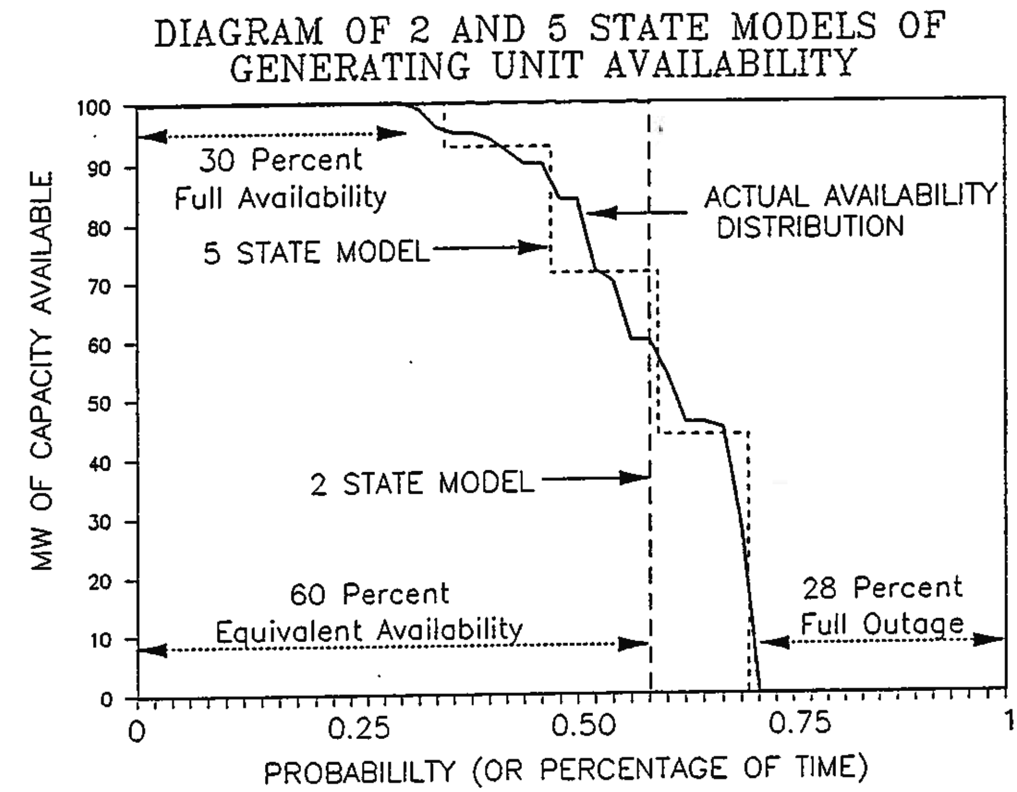
The same computerized dispatch models used for production costing calculations are frequently employed for reliability analysis. Probabilistic techniques are used to "simulate" the random nature of forced generating unit outages. Maintenance outage schedules, as will be discussed below, are usually assumed to be fixed. There are many publications that address reliability modelling generally, for example, books by Billington[6] and Sullivan.[7] Moreover, particular models each have their own documentation.

The essential inputs to computerized reliability models include capacity and outage data for each generating unit, and some representation of customer loads. Intertie support and some of the interconnection procedures are also frequently included in the model.

In modelling generating units for reliability, it is desirable to represent partial capacity outages accurately. Some reliability models are limited to a <u>two-state</u> representation of generating unit availability. That is, at any point in time the unit is assumed to have either <u>all</u> of its capacity in service, or <u>all</u> of its capacity out of service. In reality, however, generating units frequently experience partial capacity outages, in which some -- but not all -- of the generating capacity is unavailable. A <u>multi-state</u> representation of generating unit availability, is preferable to a two-state model, because with more states the actual availability distribution can be accurately represented.

This is illustrated in Figure 2, a capacity availability distribution for a hypothetical 100 MW generating unit. The solid line which declines from 100 MW at 30 percent of the time to 0 MW at 72 percent of the time represents the capacity

FIGURE 2



available from this unit. In this example, the unit is partially available in various capacity states for 42 percent of the time.

With a two-state model, however, the unit must be represented as either fully in or fully out. The capacity distribution associated with this simplified model is a single step, where the partial outages are accounted for as equivalent full outages. In the example, the equivalent availability of 60 percent would be used, with the equivalent full outage at 40 percent, so that the total amount of generation available matches the actual. Thus, the 42 percent of partial outage time is assumed to be divided between equivalent full outages and equivalent full availability (12 percent and 30 percent respectively). The shape of the single step capacity availability curve, however, is only a very crude approximation of the actual capacity availability distribution.

In contrast, the five-state model of generating unit availability, also depicted in Figure 2, is a much closer approximation to the actual availability curve. Like the two-state model, the five-state model involves approximation of the actual capacity availability curve with a step function. However, with the five-state model, more steps are used, with intermediate steps representing partial capacity availability (i.e., partial outage states). The increased number of steps allows the representation of capacity availability to match the actual distribution more closely.

This is no small matter. By using the two-state representation, a system's reliability can be significantly understated. Analysis has shown that the difference between such accurate and crude approximations of partial outages can amount to several percentage points difference in reserve requirements to meet a given reliability criterion. Thus, the terms "equivalent availability" and "equivalent forced outage rates," while accurate for energy calculations, are misleading for reliability calculations.

In reliability modelling, another pitfall related to generating unit forced outage representation is the data itself. Especially for units such as combustion turbines and diesels which are called upon infrequently, the usual outage data can be misleading. The usual equation for generating unit forced outage rate is as follows:[8]

$$\text{Forced Outage Rate} = \frac{\text{Forced Outage Hours}}{\text{Forced Outage Hours} + \text{Service Hours}}$$

Because of the high operating cost of combustion turbines and diesels, these "peaking" units are called upon only occasionally to produce electricity. That is, for these units the number of service hours in usually low and the number of attempted start-ups is relatively high. For this type of unit, a successful start-up could be followed by only a few hours of operation until the unit is intentionally shut down for economic reasons. An unsuccessful start-up might be followed by a much longer period of "forced outage time," until the repair of the unit is completed. Moreover, because these units are only rarely needed to serve load, the repair may be conducted at a very leisurely pace. Thus, for peaking units, the forced outage rate data, collected according to the usual equation does not provide a good measure of the failure rate to be expected in future system operations. While a reasonable forced outage rate to use for a particular peaking unit may be in the neighborhood of 10 percent, the historic data for the unit may show a forced outage rate of 50 percent or higher. In such cases, the higher number will overstate the unavailability of the unit, and should not be used in system reliability analysis.

The discussion of generator outage modelling above has focused upon forced, or randomly occurring generating unit failures. In simulating the reliability of an electric utility system, it is important to model planned maintenance outages properly as well. The major issue in modelling planned unit outages is the allocation of those outages throughout the study period. An annual maintenance schedule can be developed in a sub-optimal manner, such that system reliability will be very poor, even though adequate generating capacity exists. For example, scheduling one or more major resources to be out during the peak load period is likely to be poor practice, and to result in inferior system reliability.

"Optimal" maintenance schedules can be developed by using a reliability model to explore alternate plans. For this type of analysis it is usual to simulate each week of the year separately, calculating reliability indices for each. In practice, levelizing the reliability across the year will result in the best overall annual system reliability. Of course, constraints upon the scheduling of outages can be relevant to such analysis. Such constraints include maintenance crew availability, and refueling requirements for nuclear plants.

Customer loads must be represented in a reliability model. Hourly customer loads are sometimes input, while in other cases only the daily peak loads are used. The use of hourly loads is generally preferable, in that important measures of reliability such as the expected energy unserved can then be calculated. If only the daily peak loads are input to the model, then the number of events (of loss of load or dependence upon others) can be calculated, but the amount of energy involved cannot. The daily peak method, while still in use, dates back to the early development of analytic techniques for reliability analysis. With computers now widely available, the more detailed approach in which system reliability in all hours is considered, must be considered preferable.

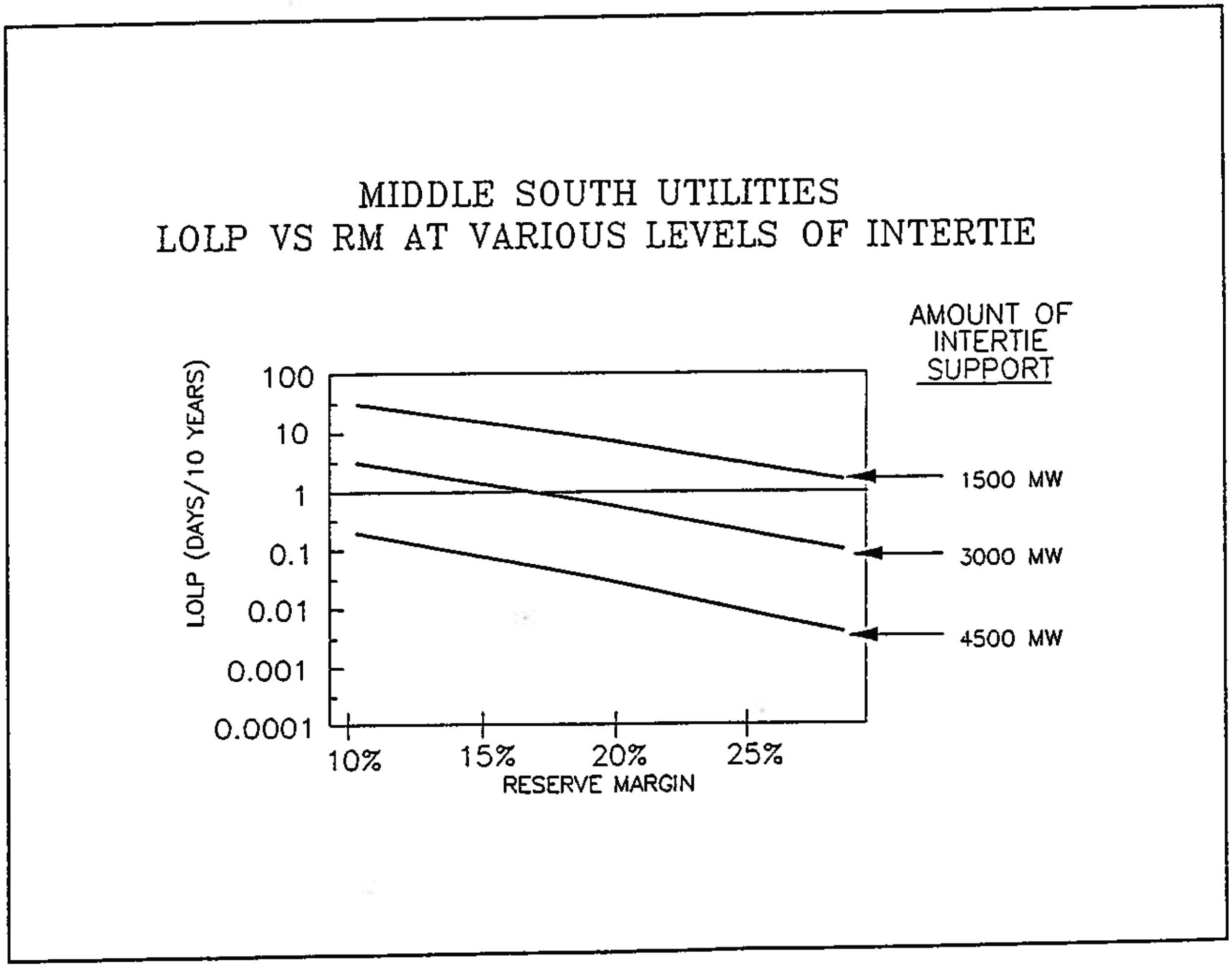
By using both the daily peak and the complete method of load representation, a rich set of reliability measures can be obtained, including the expected number of LOLP or DSCR events, the energy unserved, and, potentially, magnitude and duration information. For example, if analysis using the full hourly load set indicates an expectation of 24 hours of unserved load, and the analysis using daily peak loads indicates that 3 loss of load events are expected, then the average expected duration of each of the three events would be 8 hours (24 divided by 3).

One of the most challenging aspects of reliability modelling is accurate representation of intertie support. Transmission interconnections play a major role in providing reliability, and study results will often be very sensitive to the way in which these interties are represented. In practice, problems can be minimized by selecting the system to be studied appropriately, and by developing inputs for the interties carefully. An appropriate system to study by reliability modelling would be large enough that the role of outside systems in determining reliability is minimized, yet not so large that limits upon the transmission lines within the system will play a crucial role (unless the model being used can accurately represent such limits).

A 1984 survey of utilities by Ebasco Services, Inc., found that: "in most cases where LOLP is used, the assistance available from neighboring utilities is taken directly into consideration: either by representing them as separate resources similar to generation, or by using a two-area model, or by using the results of a reserve requirements study performed on a pool-wide basis."[9] In order to accurately represent intertie capability, transmission modelling (e.g., load flow) exercises and, perhaps, investigations of past experience, are useful.

Figure 3 is a graph of the relationship between LOLP and reserve margin parameterized as a function of intertie from an ESRG analysis of the Middle South Utilities System.[10] The large range of the graph (note that the scale is logarithmic) shows that system reliability is very sensitive to interties. For example, at a reserve margin of 20 percent, the system would experience about 10 LOLP days per ten years if it had 1500 MW of intertie support. In contrast, with 3000 MW of intertie support and all else equal, the LOLP would be less than 1 day per ten years. Finally, with 4500 MW of intertie support, the LOLP would be less than one tenth of a day per ten years.

FIGURE 3



Other Types of Reliability Analysis

There are two other common types of reliability analysis that should be mentioned briefly here. These are transmission system analysis and economic reliability studies, both of which are related to engineering reliability analysis (discussed above), yet different in both technique and purpose.

Transmission system analysis involves assessment of the adequacy of interconnections. Events such as transmission line overloading and cascading tripouts are addressed, rather than the overall adequacy of generating resources. In practice, nearly all actual service outages in the United States are the result of distribution and transmission system failures rather than generating unit unavailability.

The other type of analysis worth noting is the economic reliability study, in which the costs and benefits of providing various levels of reserves are assessed in order to determine an economically optimal margin for planning purposes. The tradeoffs involve many cost components, the most essential of which are the cost of capacity on one hand, and the cost of unserved energy demand on the other.

Such economic studies, if properly performed, provide guidance to system planners by suggesting an appropriate amount for future resource additions. They do not, however, attempt to address the question of what level of resources is required in order to provide reliable service. Nor do such studies address the specific resources that should be included in the plan. A common misuse of this type of study involves finding an "economically optimal" reserve margin for future system planning based upon the cost of peaking capacity, and then using that reserve margin to justify investments in expensive baseload capacity. New baseload capacity additions (i.e., coal and nuclear plants) should be evaluated in terms of their own overall economic impacts. To claim that such plants are justified based upon reserve margin studies which use less-expensive capacity is fallacious.

The Pacific Gas and Electric Company (PG&E) has developed a "value-based" methodology for generation planning.[11] PG&E's approach involves finding the optimal reserve margin, based upon tradeoffs between the cost of peaking capacity and the "cost" of unserved energy. Unexpected swings in load growth and resource availability are accounted for in the analysis. This study represents one of the more ambitious efforts to incorporate economic considerations into electric utility reliability analysis. The PG&E approach is designed to determine appropriate levels of reserves, not the specific type of capacity addition required. Thus, it need not suffer the type of misuse discussed above.

The engineering and economic approaches to system reliability intersect in the area of unserved energy, which is of fundamental importance to both types of analysis. The engineering approach is to limit the LOLP, and thus the amount of unserved energy, to acceptably low values. The economic approach is to ascribe a cost to the unserved energy, thus penalizing scenarios with economically unacceptable levels of reliability.

The appropriate cost to apply to unserved energy is very difficult to determine. Data on the costs incurred as a result of real and hypothetical outages are collected by surveying customers, a technique that is inherently imprecise and error prone. Further, the "costs" incurred due to power outage can vary greatly depending upon location, magnitude, and duration of the outages, which are not calculated in performing a conventional LOLP analysis. There is, therefore, a great deal of uncertainty and therefore further research required in ascribing dollar values to unserved energy demand.

Although the engineering and economic methods differ in technique and intent, in practice the results tend to be similar for systems which do not rely upon high cost fuels for a large portion of their total energy supply. This is because systems which are planned such that a reasonable LOLP criterion is maintained will experience such small amounts of outage that the price ascribed to unserved energy is unimportant. ESRG has found that for a system with a reasonable reserve margin (and therefore an LOLP of about one day in ten years) the amount of unserved energy will generally be less than one hundredth of one percent of total system energy requirements.[12] In general, the amount of unserved energy is directly proportional to the LOLP, at least in the ranges of LOLP with which we are usually concerned.

Reliability: Theory and Practice

A calculated loss of load probability of one-day-in-ten-years does not necessarily mean that some amounts of load will actually not be served for a cumulative total of twenty-four hours over a ten-year period. If interconnections with other companies are not modelled or are understated in the calculation of loss of load probability, then some of the predicted load loss will not occur, as load will be served by power from other companies. Moreover, there are also a number of standard "emergency" operating procedures for avoiding loss of load. Thus loss of load probability calculations, and associated reserve margin determinations, which do not take these factors into account will tend to underestimate reliability and overestimate the reserve margin required to meet a given loss of load probability criterion.

One important method of decreasing the probability of load loss is dynamic scheduling of maintenance. Schedules for maintenance are developed with consideration given to such factors as system production costs, labor crew logistics, and the consequences of maintenance deferral. While schedules for a particular month are often developed several years in advance, particular unit planned outages can be flexibly changed even upon very short notice. For example, if substantial amounts of capacity are forced out of service, then upcoming scheduled maintenance outages are likely to be deferred and any maintenance outages in progress are likely to be speeded up. This is a degree of flexibility not ordinarily (or readily) represented in electric utility reliability modelling. Therefore, such models would tend to underestimate system reliability.

A 1979 Electric Power Research Institute report[13] compared calculated reliability or loss of load probability to historical experience for a particular power system and found that the actual system was more reliable than any of the calculations indicated. The primary explanation given for the difference was the failure of the computer models used to perform the calculations to address "outage postponability, the management of postponable outages, and the acceleration of repair efforts during periods of need."

Other human intervention procedures which typically are not accounted for in loss of load calculations include voltage reduction, or brownouts, voluntary load curtailment and use of emergency generator ratings. While voltage reduction and voluntary curtailment do represent energy demand that is unserved, they have quite different effects than involuntary demand curtailment. Calculated LOLP generally include all the expected loss of load or unserved energy can fall into a regime that can be dealt with by one or more of the above methods before involuntary curtailment or outages need occur. Finally, even when all such emergency generation extension and supplementary measures are exhausted, actual outages can be limited by rotating them for short periods of time through local areas.

As noted earlier, prior to 1979, the New York Power Pool used an LOLP criterion of one day in ten years for planning purposes. Since that time, however, the pool has recognized the failure of the traditional loss of load probability techniques to account for human intervention and so has adopted a reliability criterion which explicitly addresses some of the emergency operating procedures which are implemented prior to actually disconnecting load. The level of reliability chosen for this criterion is "one disconnection every ten years." Disconnection in this case refers to all voluntary and involuntary interruption of service but does not include voltage reductions.

Also, as in nearly all calculations of reliability, the New York Power Pool's techniques understate reliability by not modelling the flexibility of planned outages. The Pool's new criterion corresponds to a loss of load probability of five days in ten years prior to the implementation of emergency operating procedures. Thus, the criterion accepts about four days per year of voltage reduction, and does not take account of the further potential of voluntary curtailment through customers appeals.

Conclusion

This paper has emphasized the need for a number of important considerations in reliability analysis, including:

- Clearly defined measures of reliability (DSCR, LOLP, expected energy unserved, etc.).
- Clearly defined and well founded reliability criteria.
- Accurate representation of system characteristics in reliability simulations.

Certain potentially problematical areas were addressed:

- Accurate modelling of generator outages, including multi-state representation of partial outages and appropriate use of outage data (especially for peaking units).
- Accurate representation of the magnitude and availability of external support -- either by modelling such interconnections and resources, or by defining the system under study broadly enough.
- Accurate representation of emergency operating procedures.

The observations and recommendations made in this paper should help system planners conduct accurate and complete reliability studies, avoiding analytical pitfalls. Proper studies will help to ensure that electric utility systems maintain adequate resources to serve customer load reliably and economically.

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