Docket:	**R.12-03-014**
Witness:	**Julia May**
Exhibit No.:	

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.12-03-014 (Filed March 22, 2012)

ATTACHMENTS TO THE
SUPPLEMENTAL PREPARED DIRECT TESTIMONY OF JULIA MAY
ON BEHALF OF THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

JULY 23, 2012

ATTACHMENT A:

SCE DATA REQUEST RESPONSES

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Phillip Leung
Title: Power System Planner
Dated: 07/03/2012

Question 08:

Please provide the 10-year outage history for the following lines:

a. Serrano-Villa PK #1;

b. Serrano-Lewis PK #2

Response to Question 08:

a. Serrano-Villa PK #1;
Response: There were no forced outages on the Serrano-Villa Park # 1 for the last 10 years. Scheduled outages are not readily available.

b. Serrano-Lewis PK #2

Response: SCE believes that the data request contains a typographical error. SCE believes that the question should be Serrano-Lewis #2, no PK. There were no forced outages on the Serrano-Lewis # 2 for the last 10 years. Scheduled outages are not readily available.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Phillip Leung
Title: Power System Planner
Dated: 07/03/2012

Question 09:

Has SCE analyzed CAISO's power flow modeling in this proceeding? Has SCE done its own power flow modeling for this proceeding? If so, please provide the inputs that SCE used for its power flow modeling.

Response to Question 09:

Response: SCE was involved in the initial stages and developed the initial power flow Base Case that the CAISO used for its power flow modeling in this proceeding. This is the extent of the work done by SCE for CAISO's LCR Studies. SCE did not conduct its own power flow studies for this proceeding.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Phillip Leung
Title: Power System Planner
Dated: 07/03/2012

Question Q.04 Amendment:

In CAISO's 2011/2012 Transmission Plan, CAISO includes several tables featuring lists of transmission projects. *See* 2011/2012 Transmission Plan at pp. 419-428 (Table 7.1-1 (status of previously approved projects costing less than $50M); Table 7.1-2 (showing status of previously approved projects costing $50M or more); Table 7.2-1 (new reliability projects found to be needed)).

In SCE's June 26, 2012 Testimony, SCE asserts that CAISO did not consider certain transmission mitigation that could reduce LCR need. Specifically, SCE states that "the CAISO has not investigated adding transmission facilities beyond the 2021 transmission configuration used in its analysis of need for LCR resources in the LA Basin." SCE June 25, 2012 Testimony of D. Cabbell at pp. 8-9.

a. Please provide an explanation of what transmission mitigations including adding transmission facilities as stated above, could be used to reduce LCR need.

b. Pursuant to Request No. 5(a) please provide any transmission projects identified in CAISO's 2011/2012 Transmission Plan in Tables 7.1-1 through 7.2-1 that SCE believes should be added to mitigate LCR need in the LA Basin.

c. If SCE believes that additional projects should be added that were not included in Tables 7.1-1 through 7.2-1, please list those transmission projects included their expected in-service date.

d. Has SCE proposed any transmission projects for the LA Basin or Western LA Basin? If so, please provide a list of any proposed transmission project.

i. In the list provided pursuant to Request No. 4(d) above, please identify any projects that were evaluated to mitigate contingencies by way of reconducturing.

ii. In the list provided pursuant to Request No. 4(d) above, please identify any special protection system projects that have been evaluated.

e. For each project listed pursuant to Request No. 5(b-d) above, please define:

i. the project's expected impact on LCR need;

ii. the project's reactive support;

iii. the project's voltage support; and

iv. the project's estimated cost.

Response to Question Q.04 Amendment:

a. Please provide an explanation of what transmission mitigations including adding transmission facilities as stated above, could be used to reduce LCR need.

Response: In general, any upgrades (new transmission lines, reconductoring of an existing line, and new transformers, etc) added within the Local Capacity Area. However, the Local Capacity Area Technical Studies would need to be redone.

b. Pursuant to Request No. 5(a) please provide any transmission projects identified in CAISO's 2011/2012 Transmission Plan in Tables 7.1-1 through 7.2-1 that SCE believes should be added to mitigate LCR need in the LA Basin.

Response: SCE believes that the data request contains a typographical error. SCE believes that the question should read "Pursuant to Request No. 4(a)" instead of "Pursuant to Request No. 5(a)". Based on this assumption, all transmission projects identified in the 2011/2012 Transmission Plan in Table 7.1-1 through 7.2-2 and approved by the CAISO Board should be included.

c. If SCE believes that additional projects should be added that were not included in Tables 7.1-1 through 7.2-1, please list those transmission projects included their expected in-service date.

Response: There are no additional projects that should be added that were not included in Tables 7.1-1 through 7.2-1.

d. Has SCE proposed any transmission projects for the LA Basin or Western LA Basin? If so, please provide a list of any proposed transmission project.

i. In the list provided pursuant to Request No. 4(d) above, please identify any projects that were evaluated to mitigate contingencies by way of reconductoring.

Response: Yes, SCE proposed the Del Amo-Ellis Loop In project which came on-line on 6/1/2012.

ii. In the list provided pursuant to Request No. 4(d) above, please identify any special protection system projects that have been evaluated.

Response: No special protection system projects have been evaluated with the project mentioned in question 4.d (i).

e. For each project listed pursuant to Request No. 5(b-d) above, please define:

Response: SCE believes that the data request contains a typographical error. SCE believes that the question should read "Pursuant to Request No. 4(b-d)" instead of "Pursuant to Request No. 5(b-d)".

i. the project's expected impact on LCR need;

> Response: The Del Amo-Ellis Loop In project was included in the CAISO Study before its on-line date.

ii. the project's reactive support;

> Response: Not applicable, the project did not include reactive support.

iii. the project's voltage support; and

> Response: Not applicable, the project did not include voltage support.

iv. the project's estimated cost.

> Response: As shown in Table 7.2-1 the estimated cost is approximately $5-15M.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 01:

Has SCE performed its own LCR analysis of the LA Basin or the Western LA Basin in this proceeding? If so, please provide all documents including workpapers that show SCE's analysis.

Response to Question 01:

No.

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 02.a:

In its June 25, 2012 Testimony, SCE states that it "does not agree with all assumptions used by the CAISO." SCE June 25, 2012 Testimony of M. Minick at p. 5. SCE also states that "[s]ome significant assumptions that can change the LCR need include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options." *Id* . at p. 5.

a. Please identify what specific assumptions used by the CAISO SCE does not agree with and what SCE's preferred assumption would be.

Response to Question 02.a:

SCE has internal load forecasts and renewable resource generation assumptions that are not exactly the same as those used by the CAISO in their LCR analysis. In this respect our analysis would be different than the CAISO analysis if we had done an LCR study. We did not do such a study. So, the purpose of the testimony statement is to simply note that a slightly different amount of LCR might be required using different assumptions, and SCE would prefer having flexibility in the procurement targets. So, if future studies with different assumptions change the LCR requirements, we can adjust the procurement accordingly.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 02.b:

In its June 25, 2012 Testimony, SCE states that it "does not agree with all assumptions used by the CAISO." SCE June 25, 2012 Testimony of M. Minick at p. 5. SCE also states that "[s]ome significant assumptions that can change the LCR need include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options." *Id* . at p. 5.

b. Please fill out the Load and Resource Tables that are attached hereto with SCE's preferred assumptions.

Response to Question 02.b:

These load and resource tables appear to be designed to determine the Resource Adequacy (RA) or planning reserve margin requirements of the SCE system and are not capable of determining the LCR need, which is the subject of this proceeding. If such data were available it would need to be broken down further into segments at each electrical substation in order for the CAISO to do modelling required to determine LCR need for both the "LA Basin" and "Western LA Basin". SCE cannot produce such data in time for this proceeding and in some cases it may be essentially impossible to create such data without making many arbitrary assumptions, and these assumptions would need to be agreed to by the CAISO in order for the CAISO to do another LCR analysis.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 02.c:

In its June 25, 2012 Testimony, SCE states that it "does not agree with all assumptions used by the CAISO." SCE June 25, 2012 Testimony of M. Minick at p. 5. SCE also states that "[s]ome significant assumptions that can change the LCR need include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options." *Id* . at p. 5.

c. For all assumptions used in filling out the Load and Resource Tables, please provide all supporting evidence and documentation that SCE relies on for this assumption.

Response to Question 02.c:

Please refer to the answer for question 2b.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Aaron Fishman
Title: Sr. Project Manager
Dated: 07/03/2012

Question 03.a:

SCE states in its testimony that "CAISO's assumptions in the LCR analysis recognized neither the potential for increased distributed generation (DG) nor increased localized generation." SCE June 25, 2012 Testimony of M. Minick at p. 7.

a. Please state SCE's preferred current forecast for the potential for increased distributed generation in the LA Basin and Western LA Basin.

Response to Question 03.a:

SCE does not have an alternative or preferred DG forecast for the LA Basin.

Mr. Minick's testimony intends to make the general point that the LCR need would be equal to or less than that projected by the CAISO if more distributed generation (among other things) develops in appropriate locations within the LA Basin. However SCE has no information at this point in time that provides confidence that more DG will turn up in the right locations to alleviate the LCR need. There are, however, various programs being proposed within the state that may encourage the development of additional distributed generation.

SCE expects that as future generation procurement occurs to meet local reliability needs, new information on DG projects and programs may give justification to reducing the LCR procurement need. Hence, SCE has requested the CPUC grant it flexibility to procure up to the amount proposed by the CAISO (but not necessarily the total amount proposed by CAISO) so that it can reduce procurement if the new information provides confidence that the need for new generation in the LA Basin is less than what the CAISO is currently projecting.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Aaron Fishman
Title: Sr. Project Manager
Dated: 07/03/2012

Question 03.b:

SCE states in its testimony that "CAISO's assumptions in the LCR analysis recognized neither the potential for increased distributed generation (DG) nor increased localized generation." SCE June 25, 2012 Testimony of M. Minick at p. 7.

b. Please state SCE's preferred current forecast for the potential for increased localized generation in the LA Basin and Western LA Basin.

Response to Question 03.b:

See response to a) above

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Aaron Fishman
Title: Sr. Project Manager
Dated: 07/03/2012

Question 03.c:

SCE states in its testimony that "CAISO's assumptions in the LCR analysis recognized neither the potential for increased distributed generation (DG) nor increased localized generation." SCE June 25, 2012 Testimony of M. Minick at p. 7.

c. Please provide all supporting evidence and documentation that SCE relies on for this assumption.

Response to Question 03.c:

The "increased distributed generation (DG) nor increased localized generation" that Mr. M. Minick refers to is not an assumption but a general statement of fact. If more distributed/localized generation occurs in the local area, then the LCR need could potentially be reduced. However, there are no firm programs that the CAISO could look to at this time as a basis for assuming more distributed/localized generation.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 05:

Please provide a list of any additional resources that CAISO did not consider that SCE expects to mitigate the LCR need for both the Moorehead Park area in 2021. Please include the expected MW of the project and when the project could be expected to come on-line.

Response to Question 05:

SCE does not know of any sited, licensed, or contracted new generation in the Moorpark area at this time. However, slower load growth, including some of the currently uncommitted future EE and DR, transmission line equipment modifications, additional distributed generation, and other factors may lessen the need for the amount LCR generation proposed by the CAISO. Similarly, higher load growth and more stringent reliability criteria may increase this amount.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 06:

Please provide a list of any additional resources that CAISO did not consider that SCE expects to mitigate the LCR need for the LA Basin area in 2021. Please include the expected MW of the project and when the project could be expected to come on-line.

Response to Question 06:

SCE does not know of any sited, licensed, or contracted new generation in this area at this time. However, slower load growth, including some of the currently uncommitted EE and DR, transmission line equipment modifications, additional distributed generation, and other factors may lessen the need for the amount LCR generation proposed by the CAISO. Similarly, higher load growth and more stringent reliability criteria may increase this amount. Due to these factors SCE is proposing that we have flexibility in the procurement of future LCR needs.

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET CEJA-SCE-001

To: CEJA
Prepared by: Mark Minick
Title: Manager of Resource Planning
Dated: 07/03/2012

Question 07:

Please provide a list of any additional resources that CAISO did not consider that SCE expects to mitigate the LCR need for the Western LA Basin area in 2021. Please include the expected MW of the project and when the project could be expected to come on-line.

Response to Question 07:

See answer to question 6.

ATTACHMENT B:

A Ceres Report, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility,* April 2012.

Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

A Ceres Report
April 2012

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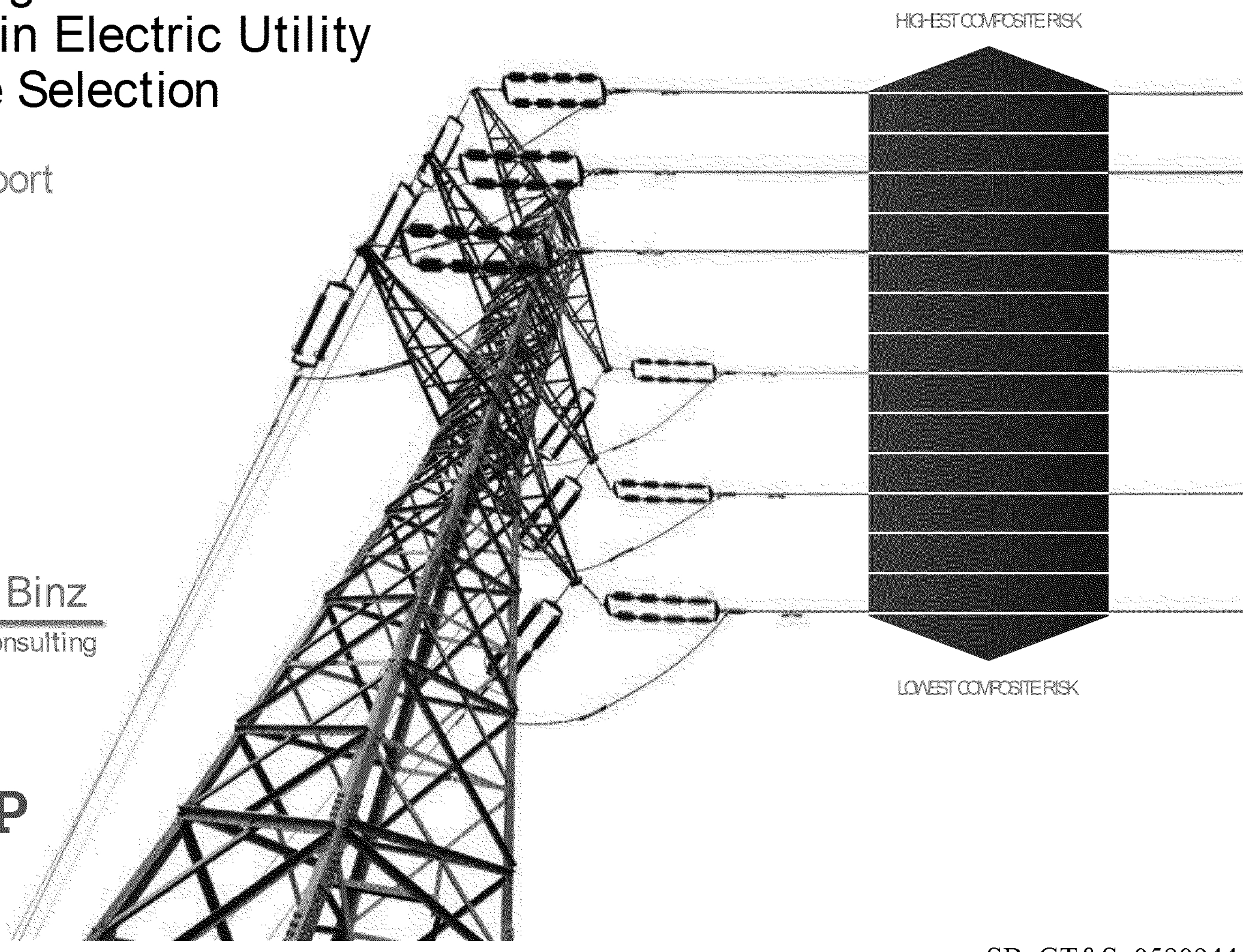

Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to state regulatory utility commissioners, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous secondary audiences, including utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

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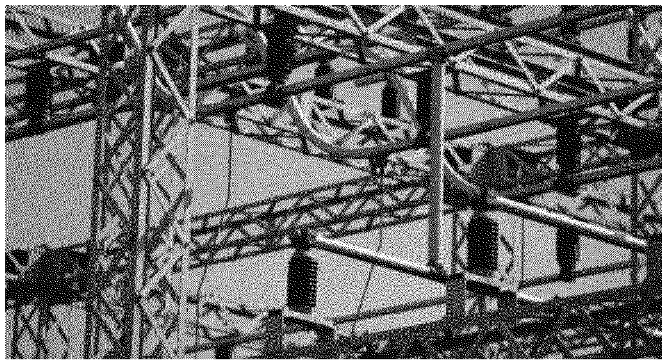
EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]



Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-firedgenerating capacity that could be retired in the 2015-2020 timeframe as a result of forthcom ing U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulationscould require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under NewEPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Figure ES-1 summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
* Construction costs higher than anticipated	* Construction delays occur
* Availability and cost of capital underestimated	* Competitive pressures; market changes
* Operation costs higher than anticipated	* Environmental rules change
* Fuel costs exceed original estimates, or alternative fuel costs drop	* Load grows less than expected; excess capacity
* Investment so large that it threatens a firm	* Better supply options materialize
* Imprudent management practices occur	* Catastrophic loss of plant occurs
* Resource constraints (e.g., water)	* Auxiliary resources (e.g., transmission) delayed
* Rate shock: regulators won't put costs into rates	* Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19 , 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency)that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" (Figure ES-2, p. 8).[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking"*; and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequenes is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically- integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

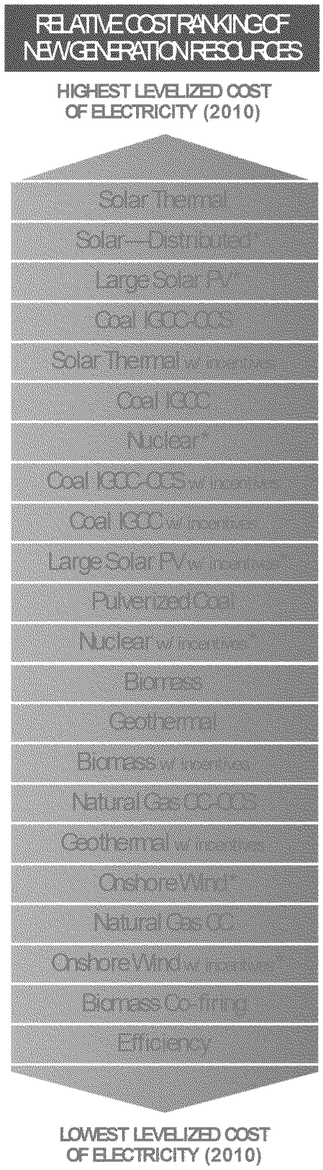


Figure ES-3

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

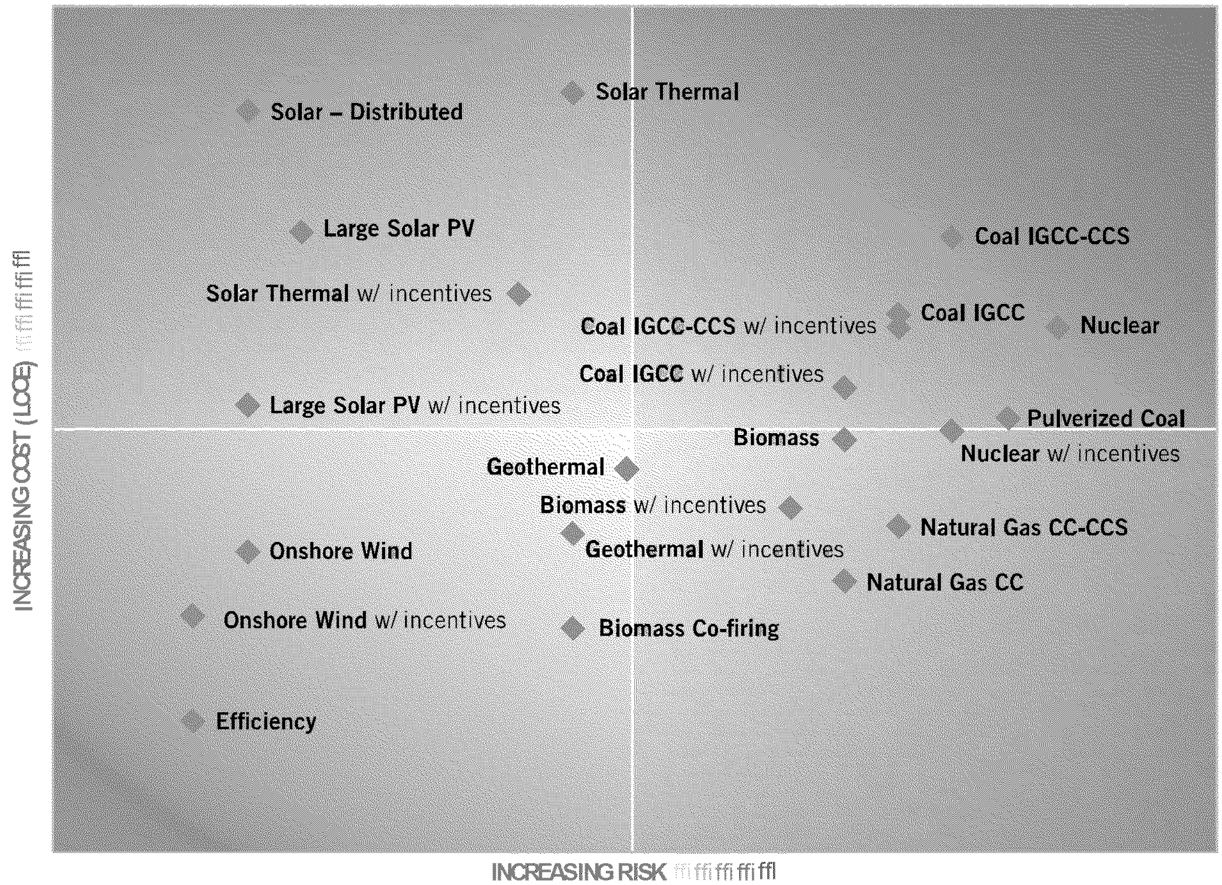
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile (Figure ES-3).

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph (Figure ES-4).[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

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PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1 **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2 **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3 **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4 **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5 **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6 **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

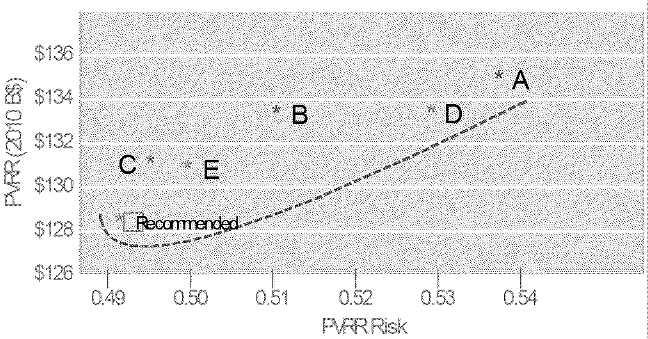
7 **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. Figure ES-5 shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Strategy A: Limited Change in Current Resource Portfolio
Strategy B: Baseline Plan Resource Portfolio
Strategy C: Diversity Focused Resource Portfolio
Strategy D: Nuclear Focused Resource Portfolio
Strategy E: EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.

- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

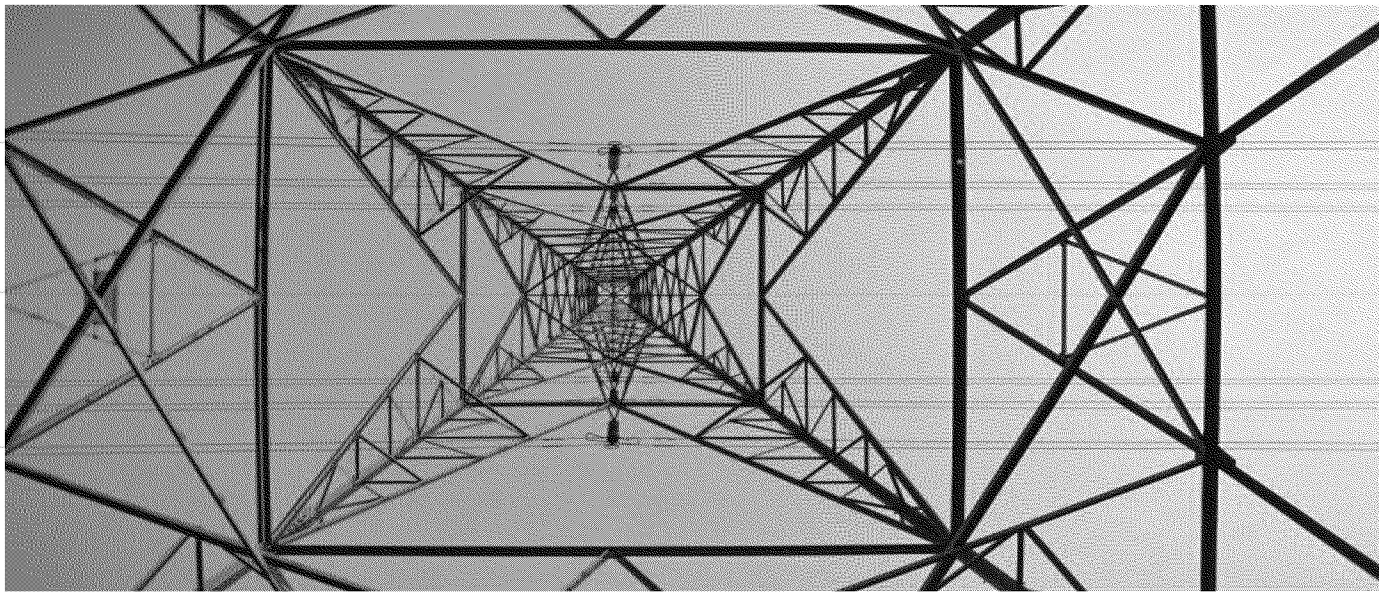
  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.

- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.

- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.



- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively** by the investment community including the rating agencies could pose longer-term threats to utilities and investors. Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefitsto resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

> **Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.**

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk = $\sum_i$ *Event$_i$* x *(Probability of Event$_i$)*

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, fillinga role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	*Time-related*
*Construction costs higher than anticipated	*Construction delays occur
*Availability and cost of capital underestimated	*Competitive pressures; market changes
*Operation costs higher than anticipated	*Environmental rules change
*Fuel costs exceed original estimates, or alternative fuel costs drop	*Load grows less than expected; excess capacity
*Investment so large that it threatens a firm	*Better supply options materialize
*Imprudent management practices occur	*Catastrophic loss of plant occurs
*Resource constraints (e.g., water)	*Auxiliary resources (e.g., transmission) delayed
*Rate shock: regulators won't put costs into rates	*Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in Figure 7. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For utility management, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For customers, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- Investors focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- Employees are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- Society generally has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial,reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

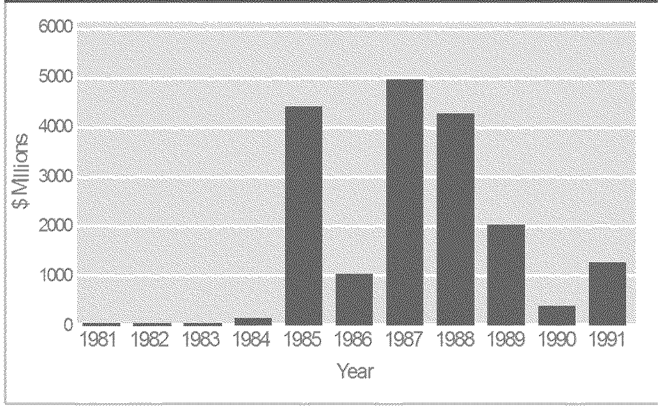
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

| Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (Figure 8).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider Figure 9. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

| Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CP UC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

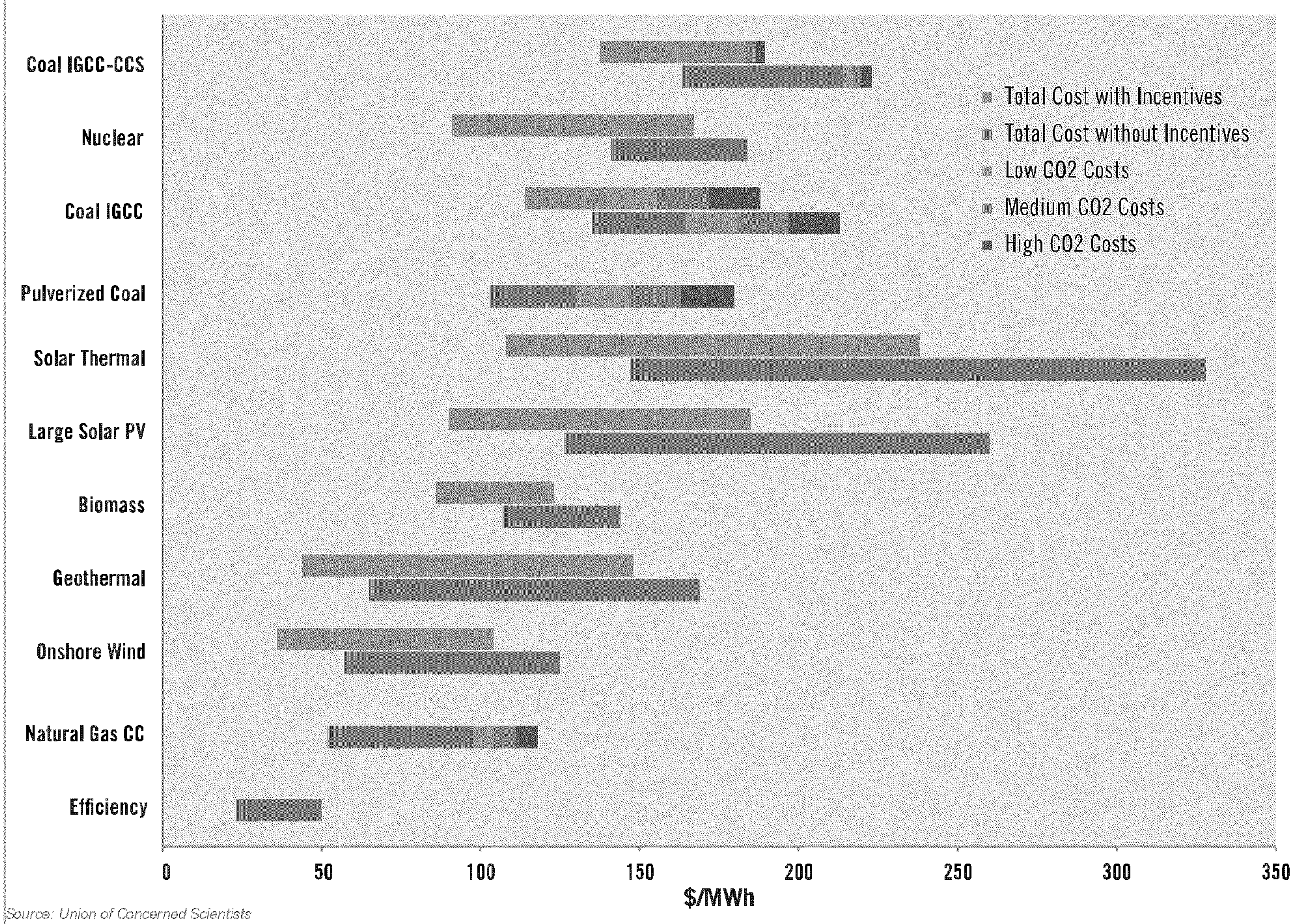
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

| Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (Figure 10).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (Figure 11).

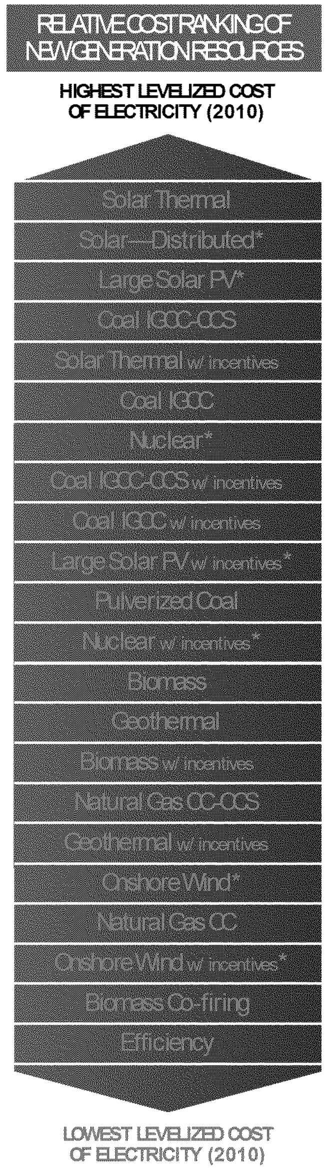
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star*, October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk... For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

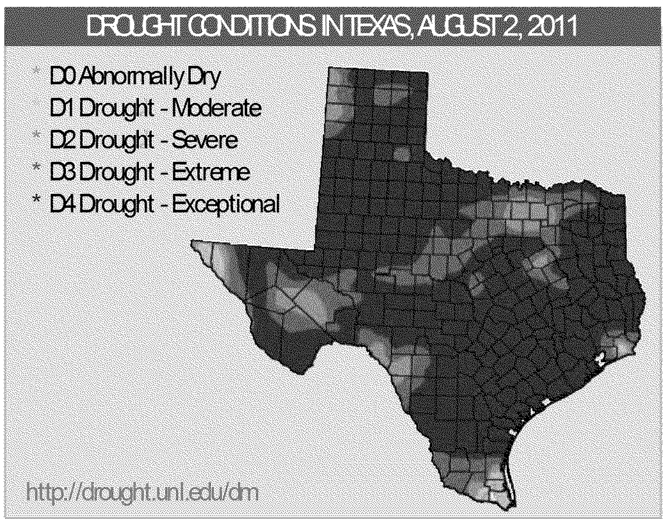
The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. Figure 12 depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in Figure 13 summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

SB_GT&S_0580971

| Figure 14

RELATIVE COST RANKING AND RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

| Figure 15

RELATIVE COST AND RISK RANKINGS OF NEW GENERATION RESOURCES WITHOUT INCENTIVES

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in Figure 14, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, Figure 15 presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in Figure 16. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

| Figure 16

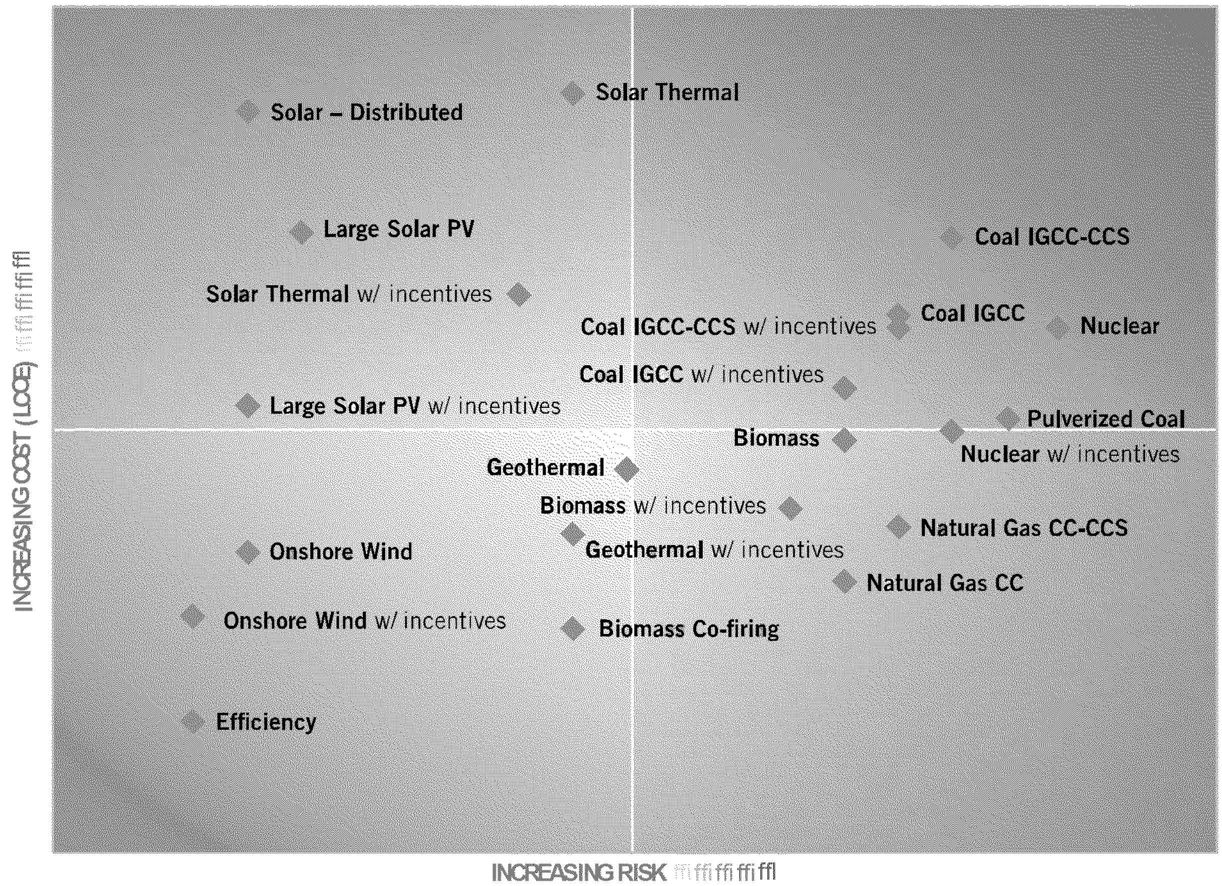
SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

| Figure 17

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. Figure 17 shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

ATTACHMENT C:

The Brattle Group Report, *ERCOT Investment Incentives and Resource Adequacy*, June 1, 2012

The Brattle Group

ERCOT Investment Incentives and Resource Adequacy

June 1, 2012

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EXECUTIVE SUMMARY

The Electric Reliability Council of Texas's (ERCOT's) energy-only market has worked well for many years to support efficient operations and to attract sufficient generation investment to maintain resource adequacy. Now, despite reserve margins declining with load growth and retirements, investment appears to have stalled. Many projects have been postponed or cancelled and no major new generation projects are starting construction. As a result, ERCOT projects that reserve margins will fall to 9.8% by 2014, substantially below its current reliability target of 13.75%. Reserve margins will decline even further thereafter unless new resources are added. Generation investors state that a lack of long-term contracting with buyers, low market heat rates, and low gas prices in ERCOT's energy-only market make for a uniquely challenging investment environment.

In response to these concerns, the Public Utility Commission of Texas (PUCT) has implemented a number of actions to ensure stronger price signals to add generation when market conditions become tight. The PUCT has enabled prices to reach the current $3,000/MWh offer cap under a broader set of scarcity conditions and is considering raising offer caps to as high as $9,000/MWh, among other measures. Following the PUCT's initiatives, forward prices have increased and more than 2,000 MW of relatively low-cost capacity additions have been announced, including uprates and reactivations of mothballed units. The critical question remains whether the recent and proposed reforms will be adequate and what other measures might be necessary to attract sufficient investment.

To inform the Commission's and ERCOT's actions, ERCOT commissioned *The Brattle Group* to address three questions:

1. **Investors and their Investment Criteria**. Identify, describe, and rank the relevant factors that influence investment decisions made by the development and financial community related to new capacity additions, capacity retirements, and repowering projects in ERCOT.
2. **Market Outlook for Investment and Resource Adequacy**. Evaluate the current drivers from both a wholesale and retail perspective that influence resource investment decisions in the ERCOT market.
3. **Evaluation of Policy Options**. Provide suggestions for ways to enhance favorable investment outcomes for long-term resource adequacy in ERCOT.

Our approach to addressing these questions and our findings are summarized as follows:

Investors and their Investment Criteria

To understand the factors affecting suppliers' willingness to invest, we interviewed a broad spectrum of generation developers and lenders and analyzed relevant financial indicators, as described in Section II. We found that investors are generally cautious after a history of investment losses. However, many could and would invest in ERCOT if revenue levels were expected to be adequate to earn a return on the investment that is commensurate with perceived risks.

The lack of long-term power purchase agreements (PPAs) in Texas's retail choice environment generally leaves much of the investment risk with investors, similar to other retail restructured markets. A number of generators also stated that the ERCOT's energy-only market design is more volatile, harder to model, and riskier overall than energy-and-capacity markets (though they acknowledged that generator revenues in ERCOT are more stable than spot prices, since most power is sold at least several months forward at prices that average out weather and other unexpected effects). Some also worried that energy-only markets can lead to extreme outcomes that might induce future regulators to intervene in the market. However, they expressed that the current Commission has demonstrated a strong commitment to markets and regulatory certainty. Overall, we believe that ERCOT's energy-only market may be only marginally riskier than energy-and-capacity markets, a view consistent with the statements of a subset of merchant investors. Both types of markets place much more risk on investors than do regulated environments without retail choice.

Considering these risk factors, some generation developers state that they will require projected returns exceeding the 9.6% after-tax weighted-average cost of capital (ATWACC) assumed by ERCOT.[1] Large, diversified investors with hedging options and the ability to finance plants on their balance sheet might be able to invest at lower returns. We estimate an ATWACC as low as 7.6% for efficiently hedged and diversified merchant generation investments.

Risk tolerances and revenue needs vary considerably by type of investor. To underwrite project-finance loans with no upside opportunities, lenders must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error. Larger borrowers can partially diversify project-specific risks and can borrow more cost-efficiently against a larger corporate balance sheet. Such investors may be able and willing to weather some bad years for a few good years as long as the discounted expected value is high enough. These are likely to be the most robust investors in a market with high price volatility. Smaller, undiversified borrowers relying on high leverage through project-specific, non-recourse debt financing with little equity, however, might ultimately be uncompetitive and pushed out of the market unless they can secure long-term PPAs with public power or other entities.

Market Outlook for Investment and Resource Adequacy

In Sections III and IV, we examine whether new and proposed rules are likely to produce prices that are high enough often enough to attract sufficient investment. Our approach includes: (1) assessing ERCOT's market and operational processes to understand how new and proposed rules will affect scarcity prices; (2) analyzing forward curves; (3) conducting economic simulation modeling to project future prices, including the frequency of scarcity prices; and (4) comparing projected energy margins to capital costs and investors' cost of capital. We conduct this analysis for a broad range of potential planning reserve margins, showing how suppliers' energy margins will increase as reserve margins fall and the market becomes tighter, or decrease as reserve margins rise. The key question is whether market prices will be high enough to support entry at an acceptably high reserve margin and associated reliability level. We address this question in the context of several major uncertainties that investors face.

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1 See PUCT (2012b), Item Number 87, p. 1. We note that ERCOT's ATWACC estimate was developed a year ago and that the cost of capital has decreased since then, as we discuss further in Section II.D.3.

We find that generators' energy margins have been low because of low gas prices and low market heat rates, except during rare price spikes. Market heat rates have been low because an efficient generating fleet and new wind generation form a very low and flat supply curve. However, current and proposed market rule changes will increase the frequency and level of scarcity prices. Forward curves have risen correspondingly, but they are still not high enough to support investment in new generation, notwithstanding recent success in attracting relatively low-cost plant reactivations and uprates.

Our simulation analysis finds that the Commission's proposals to further raise the offer cap would stimulate greater investment, but investment would still fall short of what is needed to meet ERCOT's current reliability target of "one load-shed event in 10 years," at least under current market conditions and demand response penetration. Scarcity prices would be too infrequent to support the target because if reserve margins are high enough to make load shedding very rare, scarcity pricing events would also be quite rare. This is compounded by the long "tails" of the load distribution, including rare, extreme extended heat waves such as the one in 2011. Having high enough reserves to limit load shedding even under even such challenging conditions would eliminate scarcity in most years.

We estimate that the current market design and the $3,000 offer cap would achieve a reserve margin of only 6% on a long-term average basis under current market conditions. If the offer cap is increased to $9,000, a reserve margin of approximately 10% could be achieved without reducing the frequency of scarcity prices below the level needed to support investment. This is approximately five percentage points less than the 15.25% reserve margin we estimate would be needed to achieve ERCOT's reliability target. Our 15.25% estimate is higher than ERCOT's current 13.75% reliability target because we assumed a 1-in-15 chance of extreme 2011 weather occurring, whereas ERCOT's target reserve margin study could not account for 2011 weather because it had not been experienced at the time. On average, the 10% reserve margin achieved with a $9,000 offer cap would result in approximately one load-shed event *per year* with an expected duration of two-and-a-half hours, and thirteen such events in a year with a heat wave as severe as the one in 2011. In years with less extreme weather than 2011, however, load shedding would be expected to occur less than once in ten years.

Reserve margins would differ on a year-to-year basis due to the lead times required to respond to supply shocks, such as simultaneous environmentally-driven generation retirements. Moreover, even our long-term average estimates are highly uncertain due to underlying uncertainties about market conditions, weather, regulatory risk, and investors' perceptions of these risks. The range of uncertainties we analyzed could result in average reserve margins that fall between one and seven percentage points below the 1-in-10 target reserve margin on average. For example, with only a 1-in-100 chance of extreme 2011 weather, the reserve margin achieved with a $9,000 offer cap would fall only three percentage points below the reserve margin needed to achieve the reliability target and load shedding would be expected only once every three years on average.

An important qualification to these simulation results is that they assume only the current level of demand response (DR). If several thousand megawatts (MW) of price-responsive demand were added, those resources could prevent involuntary load shedding and set prices at customers' willingness to pay, thereby increasing reliability and softening (but not eliminating) price spikes. With this much demand response, ERCOT's energy-only market design could support the current bulk power reliability target under a $9,000 price cap. However, achieving such a high demand response penetration would take years, not months, as we explain further in Section V.B.

Evaluation of Policy Options

Our finding that the energy-only market will not dependably support ERCOT's current reliability target until sufficient demand response penetration is achieved suggests that either the market design needs to be adjusted or the reliability objectives have to be revised. We present a broad analysis of policy options, preceded by a discussion of reliability objectives.

The "1-in-10" reliability standard has been used in the industry for decades, but has rarely been evaluated from an economic perspective, as we explain in Section VI. ERCOT's "1 load-shed event in 10 years" interpretation of the 1-in-10 standard is more stringent than the "1 outage day in 10 years" interpretation used in the Southwest Power Pool (SPP). Other regions use entirely different approaches based on the economic value of reliability. We also note that distribution outages cause customers to lose power 100 times more often than do generation resource shortages, suggesting that the 1-in-10 target could be too high. Even if reserve margins fall to a 10% equilibrium reserve margin, load shedding would occur approximately two-and-a-half hours per year, averaging only three minutes per customer; this compares to an average of a few *hundred* minutes per customer per year from distribution outages. Moreover, critical loads that are not behind a single distribution feeder may enjoy even less exposure to power outages, assuming load shedding protocols are designed properly. We therefore recommend that the PUCT and ERCOT evaluate their resource adequacy objectives in the context of delivered reliability, load shedding protocols, and informed by an analysis of marginal costs and benefits. We recommend determining the *desirable* reserve margin target and, separately, a *minimum acceptable* reserve margin needed to avoid extremely adverse consequences under worst-plausible weather and outage conditions.

This report does not recommend a specific course of action because the best path forward depends on policy objectives, which only stakeholders, regulators, and other policymakers can assess. To inform the choice among policy options, we describe five available options and present the advantages and disadvantages of each in Section VI:

1. Energy-only with market-based reserve margin;
2. Energy-only with adders to support a target reserve margin;
3. Energy-only with backstop procurement at minimum acceptable reliability;
4. Mandatory resource adequacy requirement for load serving entities (LSEs); and
5. Resource adequacy requirement with a centralized forward capacity market.

The evaluation criteria assessed for each option include both the reliability implications of letting the market determine the level of reliability and the market implications of having regulators determine the level of reliability. We also assess economic efficiency, compatibility with investment, regulatory stability, and the extent and complexity of necessary market design changes. Table 1 summarizes our evaluation of these policy options.

Table 1
Comparison of Policy Options

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes	Comments
1. Energy- Only with Market-Based Reserve Margin	Market	Market	Highin short-run; Lower in long-run w/ more DR	High	May be highest in long-run	Easy	- Depends on substantial DR participating to set prices at willingness-to-pay; ERCOT does not yet have much DR
2. Energy-Only With Adders to Support a Target Reserve Margin	Regulated	Market	Medium	High	Lower	Easy	- Not a reliable way to meet target - Adders are administratively determined
3. Energy- Only with Backstop Procurement at Minimum Acceptable Reliability	Regulated (when backstop imposed)	Regulator (when backstop imposed)	Low	High	Lower	Easy	- Attractive as an infrequent last resort, but long-term reliance is inefficient, non-market based, and slippery-slope
4. Mandatory Resource Adequacy Requirement for LSEs	Regulated	Market	Low (with sufficient deficiency penalty)	Med-High	Medium (due to regulatory parameters)	Medium	- Well-defined system and local requirements and resource qualification support bilateral trading of fungible credits, and competition - Cannot be a forward requirement - Flexibility: DR is like opting out; customers not behind a single distribution feeder could pay for higher reserves and reliability
5. Resource Adequacy Requirement with Centralized Forward Capacity Market	Regulated	Market	Low	Med-High (slightly less than #4)	Medium (due to regulatory parameters)	Major	- Working well in PJM - Forward construct can efficiently respond to retirements and meet needs with sufficient lead time - Transparency valuable to market participants and market monitor - Many administrative determinations

"Energy-only with market-based reserve margins" is theoretically the most efficient option because it allows customers to choose the level of supply based on prices and their value of avoiding curtailment, without having to pay for costly reserves they may not want. It also provides strong incentives for resources to be available when they are needed most. We believe that energy-only, perhaps with rare backstop procurement of short-term resources as needed to support a very minimal reserve margin, might be the most aligned with the Commission's demonstrated philosophy to let the market work. However, this would require managing public expectations about reliability implications and the potential for periodic high spot prices. Energy-only will deliver less reliability than the current target until more price-responsive demand is developed.

If the Commission and ERCOT want to maintain a higher level of reliability, the four other options we present differ in their effectiveness, efficiency, and complexity. Price adders or backstop procurement may seem appealing because they require the least modification to the existing design in the short term. However, price adders will not dependably achieve any particular reserve margin. The backstop procurement option introduces market inefficiencies and could threaten the viability of market-based investments unless it is used very sparingly to maintain only a minimum-acceptable level of reserves that is well below the "desirable" target. If policymakers decide that a higher target reserve margin must be met every year, imposing a resource adequacy requirement on LSEs is the most market-based, efficient option. Implementing such a reserve margin requirement through a forward capacity market could further increase forward competition, price transparency, and efficient investments, but these markets are quite complex and increase the importance of administrative parameters such as the load forecast.

Recommendations

Our primary recommendations are that the PUCT and ERCOT: (1) evaluate and define resource adequacy objectives for the bulk power system; and then (2) choose a policy path to meet those objectives, informed by the advantages and disadvantages of each option we have identified. We recommend defining the long-term resource adequacy framework expeditiously. Committing to a definitive course of action will resolve regulatory uncertainty and support investment. However, we urge caution about implementing major changes too quickly or without sufficient analytical support or stakeholder consideration. Complex market design changes will likely take more than a year to implement, and market participants need to be allowed ample time to prepare for the implementation of any changes.

The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments. However, we anticipate that more low-cost resources will enter the market before 2014 than are currently reported in ERCOT's Report on the Capacity, Demand and Reserves (CDR) Report, yielding reserve margins that are at least somewhat above the 9.8% currently projected.[2] If the 2014 planning reserve margin outlook fails to improve sufficiently to meet a minimum acceptable level of reliability before new generation can be added, the PUCT and ERCOT could consider soliciting additional Emergency Response Service resources as a short-term solution. However, we stress that such a backstop mechanism should be implemented with great restraint to avoid introducing a perpetual dependence on backstops or displacing market-based resources that would otherwise be developed.

In addition, and regardless of the overarching policy path selected by the Commission, we recommend enhancing several design elements to make the ERCOT market more reliable and efficient, as discussed in Section V: (1) increase the offer cap from the current $3,000 to $9,000, or a similarly high level consistent with the average value of lost load (VOLL) in ERCOT, but impose this price cap only in extreme scarcity events when load must be shed; (2) for pricing during shortage conditions when load shedding is not yet necessary, institute an administrative scarcity pricing function that starts at a much lower level, such as $500/MWh when first deploying responsive reserves, and then increase gradually, reaching $9,000 or VOLL only when

[2] ERCOT (2012n).

actually shedding load; (3) increase the Peaker Net Margin threshold to approximately \$300/kW-year or a similar multiple of the cost of new entry (CONE), and increase the low system offer cap to a lever greater than the strike price of most price-responsive demand in Texas; (4) enable demand response to play a larger role in efficient price formation during shortage conditions by introducing a more gradually-increasing scarcity pricing function (as stated above) so loads can respond to a more stable continuum of high prices, by enabling load reductions to participate directly in the real-time market, and by preventing price reversal caused by reliability deployments; (5) adjust scarcity pricing mechanisms to ensure they provide *locational* scarcity pricing signals when appropriate; (6) avoid mechanisms that trigger scarcity prices during non-scarcity conditions; (7) address pricing inefficiencies related to unit commitment but without over-correcting; (8) clarify offer mitigation rules; (9) revisit provisions to ensure that retail electric providers (REPs) can cover their positions as reserve margins tighten and price caps increase; and (10) continue to demonstrate regulatory commitment and stability. We recommend considering these ten suggestions no matter which resource adequacy framework the Commission and ERCOT select.

lower than it otherwise would be under similar time and weather conditions. The planning model would also need to incorporate price by adjusting load downward during hours in which load would be shed and prices would be at the cap. We performed a similar step in our analysis of scarcity pricing and load shedding for this study, as discussed in Section IV above; we added 1,700 MW of additional supply during scarcity and load-shed conditions based on observed errors in the load forecast model during scarcity conditions in 2011.

VI. REVIEW OF POLICY OPTIONS FOR RESOURCE ADEQUACY

This section discusses resource adequacy objectives and an array of market design options that the PUCT and ERCOT could pursue to achieve those objectives. We discuss the advantages and disadvantages of each option, although we do not recommend any one over the others because the best path depends on the policy objectives.

A. Resource Adequacy Objectives

Before pursuing any major market redesign efforts, we recommend that the PUCT and ERCOT first clarify the fundamental design objectives of ERCOT's resource adequacy construct. More specifically, we recommend considering the following questions:

1. Is the current 1-event-in-10-years (1-in-10) reliability standard yielding the appropriate and efficient resource adequacy target around which to design the ERCOT wholesale power market?
2. Should regulators determine the reliability target, or should the reliability level be determined solely by market forces?
3. Even if the target reliability level is to be determined by market forces rather than an administrative determination, do regulators wish to impose a backstop constraint preventing very low reliability outcomes?

Answering these questions will help regulators determine which of several policy paths to pursue, achieve a more efficient outcome, and reduce regulatory uncertainties for market participants.

1. Appropriateness and Efficiency of the 1-in-10 Reliability Target

Consistent with industry practice, ERCOT's reliability target for the bulk power system is based on LOLE, or the frequency of expected firm load shed events caused by supply shortages. For decades, the utility industry has used a 1-day-in-10-years bulk power standard for setting target reserve margins and capacity requirements.[207] While the origin of the 1-in-10 metric is unclear, references to the standard appear as early as the 1940s.[208] Usually, utilities and system operators offer no justification for the reasonableness of 1-in-10 other than that it is the industry standard

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[207] For a discussion of the 1-in-10 standard and alternatives, see Carden, Wintermantel, and Pfeifenberger (2011).

[208] See Calabrese (1950).

or that it is consistent with NERC guidelines.[209] Because customers rarely complain about bulk power reliability under the 1-in-10 standard and system operators and policymakers generally are not faulted if they adhere to long-term industry practices, few question 1-in-10 as an appropriate standard.

It is also helpful to understand that the 1-in-10 standard is not applied uniformly throughout the industry. For example, ERCOT and many other system operators interpret the 1-day-in-10-years standard as "1 outage event in 10 years," while other system operators such as SPP interpret the 1-day-in-10-years standard as "24 outage hours in 10 years." While the two interpretations sound semantically similar, the level of reliability they impose differs significantly. As shown in a recent case study of a 40,000 MW power system, the former definition requires a 14.5% reserve margin, while the latter requires only 10%.[210] Finally, some regions, including TVA, SERC, and WECC, do not use the 1-in-10 standard at all to set planning reserve margins, instead using a different approach or leaving this task to their member utilities.[211] For example, utilities within SERC and TVA have determined planning reserves based on explicit benefit-cost analyses of the economically optimal reserve margin. A recent NRRI whitepaper explains how these studies can be conducted.[212]

The 1-in-10 standard is also poorly-defined with respect to the events it describes. For example, the "1 event in 10 years" standard that ERCOT and many other regions use is independent of the size or duration of outage events. Small load-shed events are given the same priority as widespread, large events. For example, two 2 MW events in 10 years with a duration of 1-hour each would not be acceptable, whereas one 3,000 MW event lasting 10-hours would still meet the standard. A better-defined metric would recognize that the latter case represents poorer reliability because it requires 7,500 times more MWh to be shed. Moreover, because outage events tend to affect a larger proportion of total load in smaller power systems, 1ffinffi0 does not provide the same level of reliability for customers in differently-sized power systems. These concerns led the NERC Generation and Transmission Planning Models Task Force to adopt the better-defined metric of *normalized* Expected Unserved Energy (EUE), which is the MWh of load shed divided by the total load if there had been no shedding.[213]

Another important consideration is the role of bulk power reliability in the context of overall customer reliability. In ERCOT, the 1-in-10 resource adequacy target implies average outages of less than 1 minute per year per customer.[214] This compares to average annual customer outages

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[209] Some industry participants may believe that the 1-in-10 standard is a NERC requirement, but it is our understanding that this is not quite the case. In many NERC Regional Entities, non-binding guidelines reference the 1-in-10 standard or require a study of reliability, although the actual mandated reliability levels are determined by the utilities or RTOs themselves under state or FERC oversight. Some NERC entities, such as SERC, do not rely on the 1-in-10 standard as a guideline, see NERC (2008).

[210] See Carden, Wintermantel, and Pfeifenberger (2011).

[211] See NERC (2008).

[212] See Carden, Wintermantel, and Pfeifenberger (2011).

[213] See NERC (2010).

[214] Based on an average 2-hour, 1,500 MW outage event every 10 years in a 65,000 MW system. The 2-hour outage translates to 12 minutes of outages per year, while each individual customer would have only a 2% chance of being curtailed during those outages because only 1,500 of 65,000 MW will be shed. This results in approximately 0.3 minutes of load shed per customer per year with these assumed outage characteristics.

well in excess of 100 minutes due to outages caused by disturbances on the distribution system (and on the transmission system to a lesser extent). During severe storm events, annual outage durations can reach several hundred to several thousand minutes per customer, as shown in Table 17.

Table 17
Average Annual Minutes of Power Outage per Customer

	2008 *(min)*	2009 *(min)*	2010 *(min)*	2011 *(min)*
Centerpoint	8,690	136	111	170
Oncor	344	260	246	237
AEP Central	943	165	2	306
TNMP	47	1	41	54
Entergy	10,480	195	3	219

Source:
Data aggregated by ERCOT from utilities' Annual Service Quality Reports, see PUCT (2012a).

For these reasons, the value of maintaining a high resource adequacy standard needs to be evaluated carefully in the context of distribution- and transmission-related outages, which have a much greater impact on customer reliability. Creating market structures that further increase resource adequacy may prove to be less cost-effective than investments to improve distribution reliability.

Despite these considerations, little empirical work has been done in the industry to quantify the economics of the 1-in-10 criterion to confirm that it reasonably balances the tradeoffs between the economic value of reliability and the system capital costs imposed. Nor have the economics of the 1-in-10 target been evaluated in ERCOT specifically. We recommend that ERCOT, the PUCT, and stakeholders re-evaluate the target in terms of its overall value, policy objectives, risk, and cost-effectiveness before re-designing the electricity market in an attempt to achieve that target.

Such an economic evaluation of bulk system reliability should take into account all economic and risk mitigation benefits of increased planning reserve margins, including reduced cost of outages considering customers' VOLL, the reduced costs of emergency power purchases, and a reduced incidence of extremely high-cost outcomes during unusual market conditions.[215] Note also that VOLL varies widely by customer types, with residential customers generally having the lowest outage-related costs (often less than $5,000/MWh) and commercial and certain industrial customers the highest (often exceeding $10,000/MWh). A load-weighted average VOLL for the system is sometimes used in these evaluations. However, if load-shed events can be targeted to customers with the lowest VOLL, then the optimal resource adequacy target will be lower. We discuss options to let consumers differentiate reliability in Section VI.B.

[215] See Carden, Wintermantel, and Pfeifenberger (2011).

2. Regulator-Determined versus Market-Determined Reliability

Another important question is whether the PUCT and ERCOT should determine the desired level of bulk power reliability, or whether the reliability level should be determined solely through market forces. All other U.S. regulators have determined that reliability standards should be mandated, except to the extent that demand response allows customers to self-select a lower level of firm service. In those markets, bulk power reliability is treated as a public good with administratively-imposed standards, not unlike many other standards such as ambient air quality standards or car safety standards. Even in markets with administratively-determined reliability targets or mandates, there are a variety of market-based approaches for achieving these reliability outcomes. We examine several options of this type in Sections VI.B.2-5.

Allowing market forces to determine the level of resource adequacy is one of the chief theoretical advantages of the textbook energy-only market construct.[216] Under this theoretical design, there is no such thing as "involuntary" load shed because wholesale prices are allowed to rise high enough that eventually sufficient voluntary curtailments will bring supply and demand into balance. The resulting reserve margins and bulk power reliability levels therefore represent the most efficient outcome, based on customers' own expression of the value of reliability. However, as discussed in Section V.B above, this construct is most effective with a substantial level of DR penetration that has not yet been achieved in ERCOT. If and when sufficient DR penetration is achieved, market-determined reliability levels have a clear advantage over administratively-determined reliability outcomes. In the absence of substantial DR penetration, even a market-based approach to determining bulk power reliability must still rely on administrative approximations of efficient prices during scarcity conditions, as discussed in Section V.A.2 above and Section VI.B.1 below.

3. Reliability Target versus Minimum Acceptable Reliability

A final policy question is whether, aside from a target or optimal level of reliability, the PUCT and ERCOT also wish to separately identify a lower "minimum acceptable" level of reliability. For example, market outcomes may be allowed to vary from year to year around an economically optimal target. However, there may be a reserve margins level below which potential reliability outcomes would be unacceptable to customers and policy makers. It might be appropriate to define such a minimum resource adequacy level based on the total amount of load shedding that could occur under worst-case weather, such as that which occurred in 2011.

B. Policy Options

In this section we evaluate five distinct policy options for approaching resource adequacy in ERCOT:

1. Energy-Only with Market-Based Reserve Margin
2. Energy-Only with Adders to Support a Target Reserve Margin
3. Energy-Only with Backstop Procurement at Minimum Acceptable Reliability
4. Mandatory Resource Adequacy Requirement for LSEs
5. Resource Adequacy Requirement with Centralized Forward Capacity Market

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[216] See Pfeifenberger, Spees, and Schumacher (2009), Section IV.

ATTACHMENT D:

FERC, *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*,

Docket Nos. RM12-6-000 and RM12-7-000 (June 2012)

139 FERC ¶ 61,247
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket Nos. RM12-6-000 and RM12-7-000

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure

(Issued June 22, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The revised definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system."

The Commission also proposes to approve: (1) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case

basis; (2) NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exception from the "bulk electric system" definition; and (3) NERC's proposed implementation plan for the revised "bulk electric system" definition.

DATES: Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

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SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,247
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure — Docket Nos. RM12-6-000, RM12-7-000

NOTICE OF PROPOSED RULEMAKING

(Issued June 22, 2012)

1. Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" contained in NERC's *Glossary of Terms Used in Reliability Standards* (NERC Glossary) developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. NERC submitted its petition in response to the Commission's directive in Order No. 743 that NERC develop a revised definition of "bulk electric system" using NERC's Reliability Standards development process.[2] The revised definition of bulk electric system:

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[1] 16 U.S.C. § 824o (2006).

[2] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150, *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

(a) removes the basis for regional discretion in the current bulk electric system definition;

(b) establishes a bright-line threshold so that the "bulk electric system" will be facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources; and

(c) contains specific inclusions (I1-I5) and exclusions (E1-E4) to provide clarity in the definition that the facilities described in these configurations are included in or excluded from the "bulk electric system."

2. The Commission also proposes to approve:

(a) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, and remove elements from the definition of "bulk electric system" on a case-by-case basis;

(b) NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exceptions from the "bulk electric system" definition; and

(c) NERC's proposed implementation plan for the revised "bulk electric system" definition.

3. NERC's proposed revision to the definition of "bulk electric system" removes regional discretion and establishes a 100 kV bright-line threshold. Further, we believe that NERC's proposal offers additional clarity to the definition of bulk electric system by creating specific inclusions and exclusions within the definition, which provide

granularity with regard to common types of facilities and facility configurations and whether they are part of the bulk electric system.

4. We believe that the proposed "core" definition, including the inclusions and the exclusions, as well as the exception process should produce consistency in identifying bulk electric system elements across the reliability regions. In addition, it appears that NERC's proposed exception process to add elements to, and remove elements from, the definition of the bulk electric system adds transparency and uniformity to the process.

5. Although it is rare that the Commission would address Rules of Procedure changes in a rulemaking docket, we will do so in this instance because of the interplay between NERC's modified bulk electric system definition and the newly developed case-specific exception process set forth in NERC's proposed Rules of Procedure change. While we propose to approve NERC's petitions, we also seek comment from NERC and interested parties on certain aspects of NERC's petitions to understand the application of the proposed "core" definition, including the application of the inclusions and exclusions, and the proposed exception process to ensure consistent implementation.

I. Background

A. Section 215 of the FPA

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject

ATTACHMENT E:

Comments of Southern California Edison Company on Notice of Proposed Rulemaking, Revision to Electric Reliability Organization Definition of Bulk Electric System, FERC Docket No. Rm09-18-000, May 10, 2010

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Revision to Electric Reliability Organization Definition of Bulk Electric System	)))))	Docket No. RM09-18-000

COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY ON NOTICE OF PROPOSED RULEMAKING

Pursuant to the Notice of Proposed Rulemaking issued March 18, 2010, Southern California Edison Company hereby submits its Rulemaking Comments.

I.

INTRODUCTION

On March 18, 2010, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued a Notice of Proposed Rulemaking to revise the Electric Reliability Organization's ("ERO") definition of the term Bulk Electric System ("BES").[1] The definition of the term Bulk Electric System is important because transmission facilities within the definition are subject to NERC's Reliability Standards while non-BES facilities are not subject to the Reliability Standards, although they remain subject to state and regional reliability standards.

[1] Notice of Proposed Rulemaking, Revision to Electric Reliability Organization Definition of Bulk Electric System, 130 FERC ¶ 61,204, issued March 18, 2010 ("NOPR").

The proposal contained in the NOPR is that the Commission direct NERC to (1) revise its definition of the term "Bulk Electric System" to include all electric transmission facilities with a rating of 100 kV or greater and (2) require that every exemption for an individual transmission facility first undergo an independent review and approval of the exemption by the appropriate Regional Entity, NERC, and FERC.[2] The Commission seeks comments about this proposal.[3]

II.

COMMENTS

SCE generally supports defining the Bulk Electric System to include all electric transmission facilities with a rating of 100 kV or above. However, SCE recognizes that in some instances, the facility's rating may not be the most relevant factor to determine whether it should be included or exempted from the BES. In such instances, the NOPR's proposal to require three levels of independent review before allowing a facility to be exempt from the Reliability Standards would add excessive layers of review and paperwork without benefit, fail to leverage the expertise of the Regional Entities, and leave uncertainty for the facility operator until all three reviews are completed.

SCE proposes, as an alternative, that FERC permit Regional Entities to conduct initial transmission facility exemption reviews under approved methodologies – i.e., subject to delegation agreements – with the approval from any such review raising a rebuttable presumption of exemption. SCE further proposes that NERC and/or FERC then be permitted to further review any exemption granted by the Regional Entities and, if appropriate, repeal a Regional Entity's grant of exemption. Such a process would

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[2] NOPR, at p. 1.
[3] NOPR, at p. 26.

avoid an undue administrative burden, provide stability in planning, properly leverage the expertise of the Regional Entities, and improve the oversight role of NERC and FERC.

A. <u>Duplicative Review of Transmission Facility Exemptions Will Cause Additional Administrative Burden Without Adding Value</u>

The NOPR's proposal would impose an unnecessary administrative burden on Transmission Owner/Operators by requiring them to seek multiple layers of approval before any such facility may obtain and reasonably exercise an exemption.[4] This would be accomplished by requiring that after a Regional Entity approves such an exemption, NERC must then approve the exemption. Then, NERC must submit the proposed exemption "to the Commission for review on a facility-by-facility basis."[5] The NOPR's proposal specifies that "[a]ny such submission must also include adequate supporting information explaining why it is appropriate to exempt a specific transmission facility that would otherwise satisfy the proposed 100 kV threshold. Only after Commission approval would the proposed exclusion take effect."[6] Under such a proposal, any exemption approved by one or two reviews would not be sufficient – a third review would be required before the Transmission Owner/Operator may begin to exercise the exemption.

It is suggested that this facility-by-facility review would "allow flexibility where warranted while providing appropriate oversight to assure that there is a legitimate need for an exemption."[7] However, no explanation is offered as to why such review by NERC or Commission staff would be more effective than that of the engineers employed by the

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[4] NOPR, at p. 12.
[5] *Id.*
[6] *Id.*
[7] NOPR, at pp. 12-13.

Regional Entities who are intimately familiar with the technical conditions, design, and needs of the electrical grid in their respective regions. It is unclear why an analysis by the Regional Entities would not provide "flexibility where warranted" but two additional layers of review, administration, and paperwork would do so.

Further, the NOPR proposal does not acknowledge or address the delays that will result from the proposed multiple facility-by-facility reviews. It is clear that at a minimum, each review will require additional time for NERC and FERC staffs to conduct their analyses. However, that is only after both NERC and FERC develop and initiate their review processes – steps that will each, in all likelihood, cause significant delay in the establishment of the exemption process and raise uncertainty about the status of facilities until the multiple reviews are completed.

B. The Regional Entities are Most Familiar with the Characteristics of the Bulk Electric Systems in their Respective Regions

The NOPR's proposal would add multiple reviews before any transmission facility may be deemed exempt from inclusion in the BES.[8] If adopted, this would change the current system in which the Regional Entity alone may consider the region's supplemental criteria in considering BES exemptions – with NERC oversight of the review.[9] SCE supports the single initial review feature of the current system in which the Regional Entity considers and approves an exemption under NERC oversight. SCE believes that adding additional layers of review *before* approval of exemptions will not increase reliability and will add significant time and burdens to Transmission

[8] NOPR, at p. 1.
[9] NOPR, at pp. 2-4.

Owner/Operators. But, adding further oversight may do so, without creating unnecessary administrative burdens.

To justify the new requirement that would add two additional layers of review, the NOPR identifies one Regional Entity that the NOPR states fails to adhere to the current NERC procedure – the Northeast Power Coordinating Council, Inc. ("NPCC").[10] Rather than proposing that FERC order NPCC to conform to the NERC definition of BES, the proposal would deny the seven remaining Regional Entities their existing flexibility to consider unique characteristics of their systems – despite their current conformity and cooperation on the issue.

The remaining Regional Entities have complied with the NERC definition of BES and have delegation agreements with NERC for implementing this compliance. The delegation agreements between NERC and the Regional Entities were authorized under the Federal Power Act and the Commission's regulations.[11] Those agreements have allowed for the enforcement of Commission-approved Reliability Standards by the Regional Entities for the past several years.

These delegation agreements are consistent with the Energy Policy Act of 2005's support of the current procedure that requires the Commission to presume that "a proposal for delegation to a Regional Entity … promotes effective and efficient administration of bulk power system reliability and should be approved."[12] This efficiency is realized as the Western Electricity Coordinating Council ("WECC") and other Regional Entities become familiar with the Registered Entities in their regions and the design characteristics of their regional grids as they enforce the FERC-approved

[10] NOPR, at pp. 7-9.
[11] 16 U.S.C. § 824o(a)(7) (2010); 18 C.F.R. §§ 39.1, 39.8 (2005).
[12] Energy Policy Act 2005 § 1211, 119 STAT. 944 (2005).

reliability standards through self-certifications, spot-checks, and audits. These design characteristics are not insignificant as weather, topography and load centers vary dramatically between regions.

This familiarity with the entities and facilities in the regions provides a sound technical basis for any exemptions to the facilities of the BES for the respective region in a manner that best promotes the reliability of the nation's bulk power system.

C. **Regional Entities Have the Technical Expertise to Properly Classify the Transmission Facilities in Their Respective Regions**

Currently, the Commission gives deference to the technical expertise of NERC in the development of Reliability Standards, and NERC gives deference to the technical expertise of the Regional Entities in the application of Reliability Standards – consistent with the Energy Policy Act of 2005 and Commission-approved delegation agreements. The Regional Entities work with the Registered Entities in their regions on a daily basis and, as a consequence, understand the unique characteristics of the transmission facilities and the needs in their region. It is this deep region-specific technical expertise that guides effective determinations of exemptions to BES in a manner that, in the aggregate, best promotes the reliability of the bulk power system at the national level. The expertise of the Regional Entities is what drove the Energy Policy Act of 2005's provision that the Commission shall give deference to the technical work of Regional Entities such as WECC.[13]

[13] *Id.*

Unfortunately, the proposal before the Commission fails to leverage the technical expertise of the Regional Entities. Absent the region-based technical expertise that exists today, the exemption process would not be as effective and could be error-prone.

D. FERC Should Give Deference to the WECC BES Definition Task Force

The proposal's identity of a 100 kV threshold for BES facilities is consistent with current reliability criteria, as NERC has defined the Bulk Electric System with a 100 kV "general" threshold for decades.[14] The proposal acknowledges that seven of the eight Regional Entities have adopted NERC's definition either verbatim or with limited additional criteria, but then asserts that an absolute and inflexible rule is now required.[15]

Interestingly, the proposal notes that WECC has established a BES Definition Task Force but does not assert any deficiency with WECC's engineering group.[16] Nonetheless, the proposal does not explicitly provide or recognize that the Commission will give deference to WECC's technical expertise. The Commission's final order should provide deference for the work of the WECC BES Definition Task Force ("BES Task Force") – consistent with the Energy Policy Act of 2005.[17]

Of interest to SCE as a WECC BES Task Force participant, the proposal does not assert any technical infirmities in the Material Impact Assessment ("MIA") method being considered by the WECC BES Task Force to determine technical grounds for the exemption of facilities with a rating above 100 kV. However, the proposal then states that it has "adequate technical justification" for its proposed threshold by citing events

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[14] NOPR, at p. 13.
[15] *Id.*
[16] NOPR, at pp. 13-14.
[17] Energy Policy Act 2005 § 1211, 119 STAT. 944 (2005).

involving 115 kV and 138 kV that have either caused or contributed to "significant bulk electric system disturbances and cascading outages."[18]

The BES Task Force has recently responded to comments on its fourth draft proposal and is in the process of refining the MIA method to test for the potential exclusion of radial lines that are at voltages of 100 kV or above. The MIA will be based upon a dynamic stability testing method, as recommended by the BES Task Force. Rather than engaging in redundant and potentially unnecessary oversight of the Bulk Electric System in the WECC region, FERC could review the MIA and its results, and if it finds the method to be acceptable, allow WECC to administer the methodology for excluding transmission facilities above 100 kV. If technically sound and appropriate, FERC could allow other regions to adopt the MIA method as well. This would provide clear guidance and a more streamlined process that would benefit the nation's bulk power system.

This approach would be consistent with the proposal SCE outlined above – that Regional Entities conduct the initial exemption reviews and NERC and/or FERC would review and, where warranted, repeal the exemption within a reasonable period of time. Moreover, from the time an exemption would be granted by the Regional Entity until such possible repeal by NERC or FERC, the Transmission Owner's compliance obligations would be subject to the Regional Entity finding.

The Commission should, in its final order, provide deference to the work of the WECC BES Task Force and other Regional Entities – as provided for under the Energy Policy Act of 2005.

[18] NOPR, at p. 15.

E. FERC Should Resolve the Statutory Term "Bulk Power System"

In Footnote 24 of the NOPR, FERC proposes to further delay addressing the statutory term "Bulk Power System" when noting, "While the Commission indicated in Order No. 693 … that the Commission may reconsider the scope of the statutory term Bulk Power System in a future proceeding, in this proceeding we are addressing only the ERO's definition of the term bulk electric system."[19] The Commission is aware that numerous parties, including SCE, have sought clarification of the term "Bulk Power System" since prior to the March 2007 issuance of Order 693. In Order 693, the Commission declined to address the term "Bulk Power System", but stated it would rely on the NERC BES definition and NERC's registration process initially and would address the issue in a later order.[20]

The industry has been seeking final resolution of the statutory term "Bulk Power System" since then and through this NOPR the Commission proposes to further postpone resolution of the issue. SCE requests that the Commission act now and through this NOPR to resolve the statutory term "Bulk Power System" and that the Commission's final order recognize that the definition of BES developed under this NOPR will meet the statutory term "Bulk Power System" and no further review need to take place.

III. CONCLUSION

SCE appreciates the effort and consideration that was put into developing a methodology for redefining the Bulk Electric System and recognizes the importance of the Reliability Standards for facilities that impact the Bulk Electric System – as well as

[19] NOPR, at p. 10.
[20] Mandatory Reliability Standards for the Bulk-Power System, Docket No. RM06-16-000, Order No. 693, at p. 26, issued March 16, 2007.

the similar state and regional reliability standards that apply to non-BES facilities. SCE believes that the redefinition itself is useful and positive, if complete, but that the proposed exemption review process may not be effective. Therefore, SCE respectfully requests that the Commission accept these comments and re-design the proposed exemption review process accordingly.

Respectfully submitted,

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Dated: May 10, 2010

CERTIFICATE OF SERVICE

I hereby certify that, I have this day served a true copy of "**Southern California Edison Company's ("SCE") Comments on Notice of Proposed Rulemaking**" on all parties identified on the official service list(s). Service was effected by transmitting the copies via email to all parties who have provided an e-mail address. First class mail will be used if electric service cannot be effectuated.

Dated at Rosemead, California, on this 10th day of May, 2010 at Rosemead California.

_/s/vicki.carr-donerson_________________________
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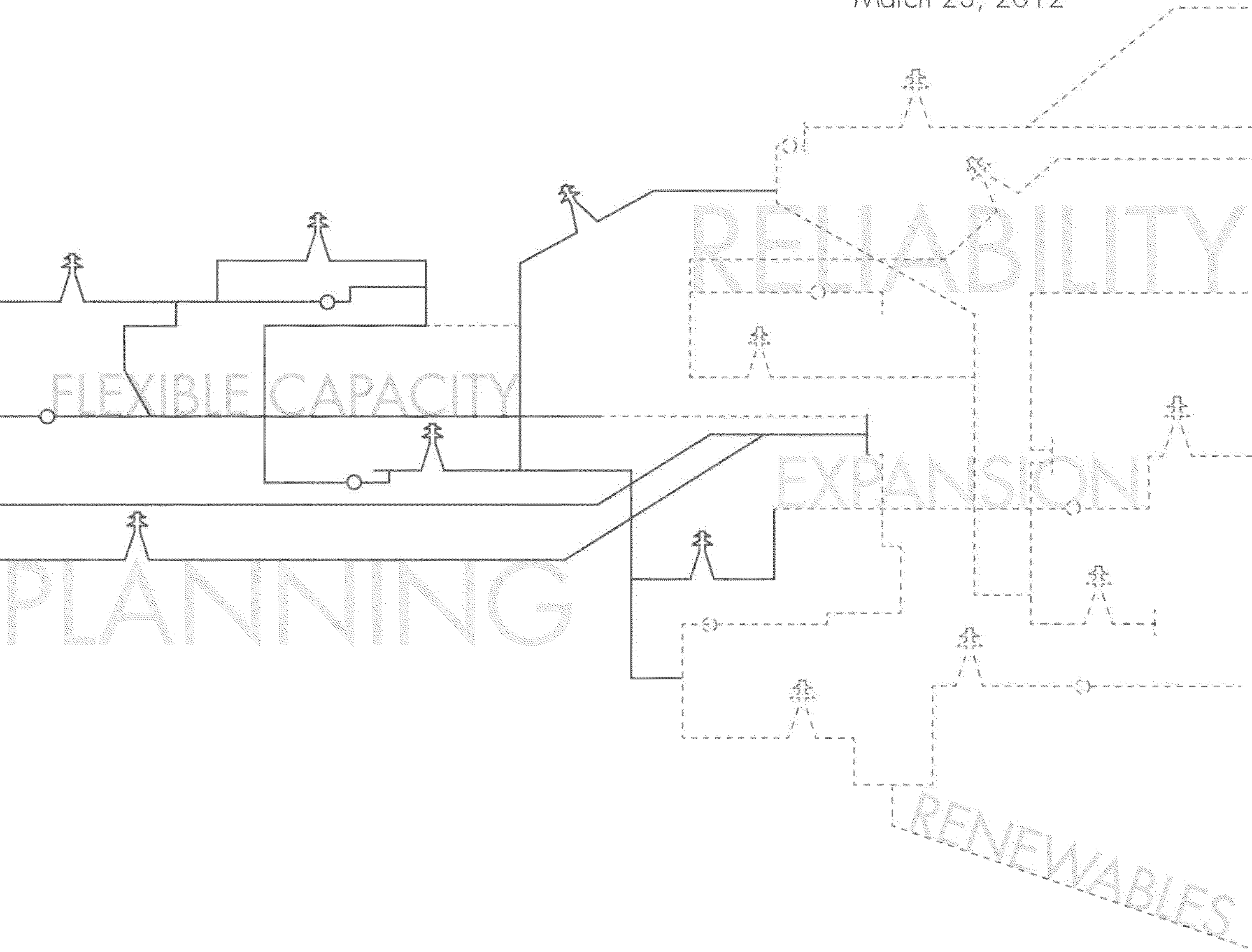
ATTACHMENT F

Excerpt from CAISO's 2011/2012 Transmission Plan

2011-2012 TRANSMISSION PLAN

March 23, 2012



California ISO

Shaping a Renewed Future

Prepared by: Infrastructure Development

Approved by ISO Board of Governors

Conclusions

It was determined that there is no need for OTC generation across all four RPS portfolios. Table 3.3-10 below is a summary of LCR and OTC generation requirements for the overall Greater Bay Area.

Table 3.3-10: Summary of LCR and OTC requirements in Greater Bay Area

LCR Area	Trajectory (MW)	Environmentally constrained (MW)	ISO Base Case (MW)	Time-constrained (MW)
Overall GBA	5,773	4,728	5,778	6,572
OTC Gen. Need	0	0	0	0

3.3.2.3.2 LCR Study Results — LA Basin Area

To determine the level of OTC generation requirements for the LA Basin in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall LA Basin;
- Western LA Basin;
- Ellis sub-area; and
- El Nido sub-area.

The Western LA Basin and Ellis sub-area drive the need for OTC units. The Ellis sub-area needs these units to mitigate a voltage collapse issue. The Western LA area needs these units to mitigate an overloading issue. The overall LA Basin generation requirements also incorporate the need for this OTC generation.

Area Definition for Overall LA Basin

The transmission tie lines into the LA Basin are:

1. San Onofre-San Luis Rey #1, #2, and #3 230 kV lines;
2. San Onofre-Talega 230 kV line;
3. San Onofre-Capistrano 230 kV line;
4. Lugo-Mira Loma #2 & #3 500 kV lines;
5. Lugo-Rancho Vista #1 500 kV line;
6. Sylmar-Eagle Rock 230 kV line;
7. Sylmar-Gould 230 kV line;
8. Vincent-Mesa Cal #1 and #2 230 kV lines;
9. Vincent-Rio Hondo #1 and #2 230 kV lines;
10. Devers-Red Bluff #1 and #2 500 kV lines;

ATTACHMENT G

CAISO's Addendum to 2011/2012 Transmission Plan

Addendum to:
Board-Approved 2011/2012 Transmission Plan

Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results

June 12, 2012

Addendum to Board-Approved 2011/2012 Transmission Plan Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results

This Addendum to the Board-approved ISO 2011-2012 Transmission Plan (March 23, 2012 version) updates the study results for the LCR ***sensitivity*** analyses of the mid net load scenario conducted at the request of the state agencies (CARB, CEC, and CPUC) as set out in Section 3.4.2, page 254 of the 2011/2012 ISO Transmission Plan.

In that sensitivity analysis of the mid net load scenario, incremental uncommitted energy efficiency and additional combined heat and power, as provided by the state energy agencies (i.e., CPUC and CEC), were modeled in the 2021 environmentally constrained portfolio study case. The Addendum provides updated study results for the incremental uncommitted energy efficiency scenario, and new results for additional combined heat and power assumptions. The updates results also reflect the modeling of the Board-approved Del Amo – Ellis 230kV loop-in project that has been advanced to be in service in 2012. The Del Amo – Ellis 230kV loop-in project was not yet an approved project when the previous analyses took place, and was originally targeted to be in service in 2013.

As mentioned at the ISO's December 8, 2011 stakeholder meeting, the ISO treats these studies in which incremental uncommitted energy efficiency and additional combined heat and power as ***sensitivity studies***, which were requested by the state energy agencies (i.e., the CPUC and CEC) to evaluate the impact to potential generation need in the LA Basin area had these programs materialized. The ISO considers these studies as sensitivity studies due to the uncertain nature of these programs whether they would materialize at the forecasted locations.

The following section 3.4.2.1 replaces and supersedes previous section 3.4.2.1 (pages 255 – 256) in the ISO 2011-2012 Transmission Plan (March 23, 2012 version).

3.4 Assembly Bill 1318 (AB1318) Reliability Studies

3.4.2.1 Study Results

The results of study items #1, 3 and 4 are provided in Section 3.3.2 (OTC Reliability Assessment Study Results). In this section, only new study results for item #2 above are reported. The following table includes assumptions provided by the CPUC and CEC in regards to assumptions of incremental uncommitted energy efficiency (EE) and combined heat and power (CHP) values for SCE and SDG&E.

Table 3.4-1: State energy agencies' provided assumptions on incremental uncommitted EE & CHP

Load Serving Entities	2021 Incremental Uncommitted EE (MW)	2021 Incremental Uncommitted CHP (MW)
SCE	2,461	209
SDG&E	496	14

The following presents a series of ***sensitivity*** study results with incremental uncommitted EE and/or additional CHP modeled for SCE and SDG&E. The study results are provided step by step to provide information regarding the incremental impacts of EE, CHP and the Del Amo-Ellis 230 kV loop-in project, respectively.

Table 3.4-2 provides a summary of study results with incremental uncommitted EE only and without the Del Amo – Ellis 230kV loop-in project[1]. These changes are triggered by the following:

LA Basin's total LCR requirements:

ϕϕι For this update, the ISO dispatched additional base-load generation in San Diego LCR area[2] to adequately mitigate a voltage instability concern under an N-1-1 contingency condition (i.e., Sunrise Powerlink and Southwest Powerlink). This minimum level of generation need in San Diego for this sensitivity study was modeled to ensure that we would not underestimate the generation need in the LA Basin LCR area. Previous studies had generation at a lower level in the San Diego area after modeling of the incremental uncommitted EE; however, this lower generation level turned out to be inadequate for mitigating the critical N-1-1 contingency voltage stability concern. Due to the interaction between LA Basin and San Diego LCR areas, the updated generation adjustment in turn resulted in having lower overall LCR requirements for the larger LA Basin.

Western LA Basin's new local generation requirements:

ϕϕι In the previous sensitivity studies, the ISO inadvertently monitored the Serrano – Villa Park #2 230kV line, which has higher rating than its parallel Serrano – Villa Park #1 230kV line. In this updated study, the ISO correctly monitored the lower rated constrained line (i.e., Serrano – Villa Park #1 230kV line). This resulted in higher new local generation requirements[3] to mitigate identified overloading concerns. The generation adjustment above for San Diego LCR area was included in this analysis for the Western LA Basin.

[1] The Del Amo – Ellis 230kV loop-in of Barre substation project was accelerated for summer 2012 due to extended outage of the San Onofre nuclear generation. This project brings Del Amo – Ellis 230kV line into Barre Substation, creating Del Amo – Barre and second Barre – Ellis 230kV lines.
[2] The total generation within San Diego LCR area for this sensitivity study is approximately 1,900 MW.
[3] The definition of new generation requirements in this section refers to the repowering of once-through cooled generation with acceptable cooling technology.

Table 3.4-2: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental EE

Portfolios	Area	LCR			New Gen. Required ? ^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,847	869	6,716	Yes	Serrano - Villa PK#1	Serrano - Lewis #1 / Serrano - Villa PK#2
	LA Basin Overall	7,135	1,519	8,654	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range		868 - 1,437 MW plus SONGS				New generation need ranges from most effective to less effective locations
	Ellis**	434	124	558	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	327	91	418	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA

** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering), but two shunt caps are still needed.

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Table 3.4-3 provides a summary of study results with incremental uncommitted EE and incremental uncommitted CHP. With the additional uncommitted CHP modeled for the LA Basin as well as the San Diego LCR area, the need for new generation requirements in the Western LA Basin LCR area is lower than the scenario in Table 3.4-2. However, the total LCR needs in the larger LA Basin increase slightly, due to the lower effectiveness of the additional CHP.

Table 3.4-3: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental uncommitted EE and CHP

Portfolios	Area	LCR			New Gen. Required ?^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,895	869	6,764	Yes	Serrano - Villa PK#1	Serrano - Lewis #1 / Serrano - Villa PK#2
	LA Basin Overall	7,203	1,519	8,722	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	782 - 1,301 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis**	388	124	512	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	284	91	375	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA

** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering) but two shunt caps are still needed.

Table 3.4-4 provides a summary of study results with incremental uncommitted EE, uncommitted CHP and the Del Amo – Ellis 230kV line loop-in project modeled. With the loop-in project in service, it eliminates the need for local generation in the Ellis sub-area for the mid net load sensitivity analyses. However, because the loop-in project has the effects of reducing impedance in the southern Orange County area, it causes more power flow through the area, thus increasing the overload on the Serrano – Villa Park #1 230kV line under an N-1-1 contingency. Therefore, more local generation would be needed to mitigate this overloading concern.

Table 3.4-4: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental uncommitted EE, CHP and Del Amo – Ellis 230kV loop-in project

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (Mw)	Total (MW)	New Gen. Required ? ^	Constraint	Contingency
Environmentally Constrained (Mid Net Load Condition)	Western LA	6,155	869	7,024	Yes	Serrano - Villa PK#1	Serrano - Lewis #1 / Serrano - Villa PK#2
	LA Basin Overall	7,288	1,519	8,807	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	1,042 - 1,677 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis	0	0	0	No	None	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	274	91	365	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA.

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering).

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ATTACHMENT H

Excerpt from Lawrence Berkley National Laboratory Report: Tracking the Reliability of the U.S. Electric Power System

LBNL-1092E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Tracking the Reliability of the U.S. Electric Power System:

An Assessment of Publicly Available Information Reported to State Public Utility Commissions

Joseph H. Eto and Kristina Hamachi LaCommare

October 2008

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Executive Summary

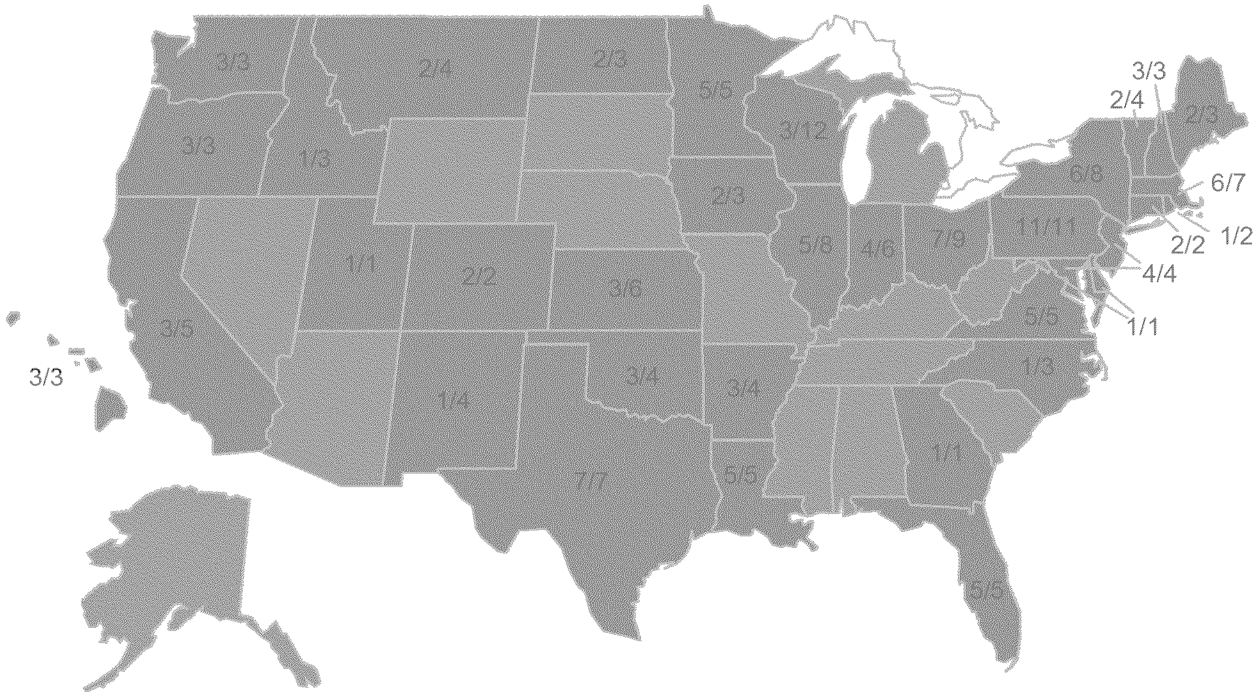
Large blackouts, such as the August 14-15, 2003 blackout in the northeastern United States and Canada, focus attention on the importance of reliable electric service. As public and private efforts are undertaken to improve reliability and prevent power interruptions, it is appropriate to assess their effectiveness. Measures of reliability, such as the frequency and duration of power interruptions, have been reported by electric utilities to state public utility commissions (PUCs) for many years. This study examines current state and utility practices for collecting and reporting electricity reliability information and discusses challenges that arise in assessing reliability because of differences among these practices.

To collect information on current practices and rules that guide utility-reported reliability information, we contacted all 50 state PUCs as well as the District of Columbia (DC) PUC. When permitted by state practices, we also collected a large sample of publicly available, actual reliability information reported by utilities to the PUC for year 2006. In total, we received information provided by 123 utilities to 37 state PUCs (see Figure ES-1). In aggregate, the reliability information we collected represents over 77% of total electricity sales by state-regulated investor-owned utilities or nearly 60% of total U.S. electricity sales.

Our assessment focused on three reliability metrics: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI). SAIDI and SAIFI measure the duration and frequency, respectively, of sustained interruptions; MAIFI measures the frequency of momentary interruptions. Taken together, these three metrics can be used to develop a comprehensive assessment of reliability nationwide.

Our findings regarding state PUC practices and rules on reliability information reported by utilities are summarized as follows:

- Thirty-five state PUCs, including DC, require routine reporting of reliability event information. This is a net increase of 10 state PUCs over the number reported in a similar survey conducted by the National Regulatory Research Institute (NRRI) in 2004.
- These 35 PUCs require annual reporting of SAIDI and SAIFI and/or the Customer Average Interruption Duration Index (CAIDI), which, along with SAIFI, can be used to derive SAIDI. Only two state PUCs require reporting of MAIFI.
- Twenty-one PUCs have reporting requirements that formally define major events. Of these 21, four require reporting following the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices, which introduces a consistent means for defining major events using the concept of "major event days."
- An additional four PUCs receive reliability information from utilities, though not as a result of a formal reporting requirement.
- Thirty-seven state PUCs, including DC, make publicly available or summarize in publicly available documents, the reliability information they collect from utilities.



State PUCs that provided information (number of utilities for which LBNL received information/total number of state-regulated utilities)

State PUCs that did not provide information

Figure ES- 1. Summary of States that Provided Utility-Reported Reliability Information

Our findings regarding utility practices for collecting and reporting reliability information to state PUCs are summarized as follows:

- All utilities reported SAIDI and SAIFI (and/or CAIDI). Only 12 of the 123 utilities reported MAIFI.
- Summary statistics for reported SAIDI, SAIFI, and MAIFI exhibit observable though not statistically significant variations across census regions.
- The definition of and practices for recording sustained and momentary interruptions have evolved over time leading to inconsistencies among utilities.
- Differences in the definition of a sustained interruption do not appear to affect SAIDI or SAIFI in a statistically significant manner.
- Utilities define major events as a means for distinguishing between utility performance in planning for and responding to routine interruptions versus that for non-routine or extraordinary interruptions.
- The definition of a major event is not consistent among the majority of utilities.
- IEEE Standard 1366-2003 introduces a consistent means for defining major events using the concept of "major event days."
- Some utilities report SAIDI and SAIFI both including and not including major events; other utilities only report SAIDI and SAIFI not including major events.
- When major events are not included, SAIDI is lowered relatively more than SAIFI compared to when major events are included.
- Many utilities report descriptive information on each major event.

- Use of IEEE Standard 1366-2003 does not appear to bias SAIDI or SAIFI values compared to using prior definitions of major events.

We also collected information on bulk power system emergencies reported by utilities in near real-time to national bodies in 2006, including the U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC), and compared aspects of this information to that reported by utilities to state PUCs. Our findings are summarized as follows:

- Information on electricity reliability reported to these two national bodies consists of descriptive information that is reported in near real-time on individual, large events that affect the bulk power system. The reporting takes place in near real-time because an important purpose of the reporting is to notify relevant industry and public bodies of significant power system events that may require immediate response. With few exceptions, the same information is reported to both DOE and NERC at the same time.
- Many, but not all, events reported to these national bodies also cause power interruptions to customers. For these events, the number of customers affected is reported.
- An initial assessment of these events supports the conventional wisdom that the majority of power interruptions experienced by customers are not due to large events that affect the bulk power system; they are due to more localized events that affect only utility distribution systems.
- It is difficult to cross-reference information reported to national bodies on individual large bulk power system events that cause power interruptions, as defined by these national bodies, with information reported to state PUCs on individual major events, as defined by either the PUC or the reporting utility.

From these findings, we draw the following conclusions and recommendations:

- State PUC interest in electricity reliability is growing.
- However, differences in utility reporting practices hamper meaningful comparisons of reliability information reported by utilities to different state PUCs and, therefore, may limit the effectiveness of efforts to measure the effectiveness of efforts to improve reliability.
- Efforts to eliminate differences that are solely due to reporting practices are just beginning. These efforts, which focus on using standard definitions, such as those promoted by IEEE Standard 1366-2003, are promising and should be encouraged.
- Until IEEE Standard 1366-2003 is adopted universally, regulators concerned about the definition and treatment of major events in reporting reliability information should consider requiring reporting of SAIDI and SAIFI both including and not including major events, as well as descriptive information on each major event.
- More work is required to better understand the sources of discrepancies and the importance of seeking greater consistency between reliability information reported to national bodies and that reported to state PUCs.

ATTACHMENT I

Excerpt from SCE December 2011 Outage Report

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL® Company

December 2011 Outage Report:

Restoration and Communications Challenges and Root Cause Evaluation

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Appendix A

Cause to Corrective Action Matrix

Root Cause Addressed	Corrective Actions	Interim Actions
Root Cause 1 SCE's methods for collecting and analyzing storm damage information are not sufficient for events of this magnitude, limiting its ability to make accurate and timely damage assessments and estimated restoration times.	**Corrective Action 1** Develop an improved damage assessment method that integrates information from *** * ****** * ********** * ****** * ****** * ********* System, Damage Assessment ***** * ********** * *** * ******* Centers. The final damage restoration projections should establish a conservative estimated restoration time based on initial damage assessment, plus extra time for contingencies. Integrate the output of this methodology with formal communications to the appropriate SCE storm and senior leadership team.	**Interim Action 1** Develop a tool for assessing damage assessment and estimating restoration time, to be used by the Storm ******** * ******* * **** * includes the following: *********** * ** * ********* the magnitude of the damage such as: circuit breaker positions * **** * ** * * ****** * ***** * down calls, quick field assessment reports, analysis of circuit problems and potential causes; * * ******** * **** * **** * **** down, transformer down and damage restoration estimates; * * ********* * **** * **** * standard travel times, parts acquisition, crew deployments and restoration estimates to determine overall restoration time; * * *********** * ***** * to be added based on incomplete information; * * * * ****** * *** * ***** * * response that includes personnel in the organization capable of implementing this damage assessment tool.

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Root Cause 2	Corrective Action 2	Interim Action 2
SCE policies, such as those regarding safety around downed wires, can delay damage estimates and restoration efforts in major storms, but the company's Event Response and Recovery Protocol does not take those effects into account, preventing it from adjusting its response to compensate for those delays.	Assess the impact of any new ** * ******* * * * * * ****** against the ability of the organization to restore power following a storm or major event. This assessment should include part time requirements, such as System ********* * ******** * * * what provisions need to be adjusted in order to facilitate timely restoration of power.	****** * *** * *********** * ******** * **** * ******** * Guidelines" to improve restoration time without compromising public safety. Review the new policy against impacts and risks associated with the Event Response and Recovery Protocol. This new policy would be analyzed for its impact to storm restoration and then reviewed and approved by the appropriate senior leadership before implementation. Consideration should be taken for use of other resources, such as Field Service Representatives, to maintain safety to the public and allow first responders to focus on service restoration.

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Contributing Cause Addressed	Corrective Actions	Interim Actions
Contributing Cause 1 SCE's Event Response and Recovery Protocol is not sufficient for responding to extensive, high concentration storm damage.	**Corrective Action 3** Revise the Event Response and Recovery Protocol to address the following: * * ******* * ***** * *********** for activation of the Corporate Emergency ********** * ****** * * * * ****** * ****** * assessment responsibilities to minimize overlapping damage reporting. * * ****** * **** * ***** * with the appropriate personnel assigned when work group coordination is required. * *** * ******* * * *********** grounding personnel with line clearing crew when grounding requirement is in effect.) * * ********* * ***** * jurisdictional control for switching, clearance and assignment of work for events involving extensive, high concentration damage where clearance and switching requests exceed switching center capability. * * ******* * *********** * resources to track and input work status in ****** * ********** * System.	**Interim Action 3** Develop a method to split jurisdictional responsibility and temporarily assign switching restoration activities to operators at adjacent switching centers. Periodically, workload on Switching Center employees exceeds their ability to comprehensively manage the affected area. A typical symptom of this is a delay in issuing switching orders or line and equipment clearances. When these delays significantly affect the restoration times, jurisdiction can be transferred to an adjacent Switching Center to assist in managing the restoration effort.

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Contributing Cause 2	Corrective Action 4	Interim Actions
SCE's storm response communication plan is not sufficient for setting realistic expectations for service restoration during major events.	Establish a communication strategy that includes: * * ******** * *** * ********* * SCE employees informed in affected areas * * *** * ** * ******** * ******** * for current response status and projections, including the source of the numbers and the person responsible for them; * * *** * ** * ************ storm data to predict call volume based on weather predictions; * * *** * ** * *** * **** * ******** * weather predictions to refine National Weather Service predictions; * * ********** * *** * ****** * as it occurs to detect consequential differences between its predicted severity and area of impact versus the actual; * * ******** * *** * *********** * voice messages to reflect damage being different than expected, particularly for high concentration damage; * * ******** * ******* * content to manage public expectations.	None

Contributing Cause 3	Corrective Action 5	Interim Actions
SCE does not have a method to reliably compare actual restoration rates relative to predicted rates in order to gauge whether Estimated [illegible] met.	Revise the Event Response and Recovery Protocol to include the following: [illegible] restoration rate with clearly defined roles and responsibilities; [illegible] monitoring restoration rate; [illegible] projections will not be met.	None

Additional Opportunities for Improvement

Since beginning this Root Cause Evaluation, SCE has engaged with various stakeholders and received feedback and additional suggestions for improving restoration, communication with customers, and cooperation with agencies and communities. SCE has also received and reviewed the February 1, 2012, report prepared by the Consumer Protection and Safety [illegible]

[illegible]

[illegible] 2012. SCE met with the city managers and other stakeholders representing fifteen affected cities, and with other city mayors and local officials, to gather their input. SCE has worked with first responders to discuss how to best coordinate resources in a major event such as the November 30 windstorm. Finally, SCE has worked with its own employees to discuss how to better provide service and communications during major incidents.

As a result of these activities, SCE has identified additional opportunities for improving SCE's Event Response and Recovery Protocol:

Storm Categorization: Revise the storm categorization criteria to ensure their appropriateness and clarity, including the efficacy of maintaining the highest category declared until normal operations are resumed.

Mutual Assistance: Revise the mutual assistance component of the Protocol to ensure the [illegible] warrant it. Identify ways to improve integration of mutual assistance crews by reducing their mobilization time and increasing their self-sufficiency.

Incident Command System: Review SCE's Incident Command System, used for emergency management, to identify opportunities for integration and cohesion between the ICS and

*** * ********* * ********** * ****** * * ********* * ***** * ****************** ** ****** * appropriate.

Event Recovery Manager: * ****** * *** * ***** * ******** * ******* * **** * ** * *** * ***** position as it relates to storms, including triggers that warrant the staffing of this role and a determination of the appropriate span of control. This should factor into how to perform jurisdictional split as discussed in Corrective Action 3.

Staffing: Review the description of organizational response for each storm classification and clarify the methodologies used to establish minimum staffing requirements and develop storm organization charts and rosters.

Outage Management System: Assess system performance during major storm events when ****** * ** * ****** * **** * ***** * * **** * ****** * ***************************** * ** * predict the extent of outages to enhance the accuracy of these predictions.

Smart Meters: Evaluate both interim and permanent solutions involving the use of Smart ***** * **** * ** * ****** * ********** * *** * ************ ************************* * ***** * for the early assessment of customer outages to help determine the magnitude of system damage and to determine the number of customers still remaining without power during the restoration activities.

Work Flow: Assess the performance of the repair work initiation capability of the field crews' mobile devices, as well as the effectiveness of the process from the point at which repair orders are created, materials are ordered and filled, work is scheduled and crews are dispatched. Identify opportunities to improve performance and implement those that provide the most benefit and are also the most feasible.

Call Center Capacity: Review the Call Center infrastructure, processes, technology and staffing capacity requirements during events where information updates are provided to discrete groups of customers affected by an outage, versus those occasions when community-wide or event-level messaging is appropriate. Identify opportunities to improve performance and implement those that provide the most benefit and are also the most feasible.

Stakeholder Coordination and Communication: Identify and implement improvements in emergency communications with public agencies and elected officials.

Medical Baseline Customers: Identify and implement opportunities to identify and *********** * **** * * * ******** * **** * ******* * ************************** * ** * ***** ** * *** * * * ******* * ************ * ******* * * *** * **** *************** **** * *** * ******* * ** * ******* * *** * * * ***** * ******* * *************************** ********** * that an unplanned outage will exceed 12 hours to let them know of the extended outage and ********* * **** * ** * ******* * ** * ********* * ***** * ****************************** * cannot be reached by telephone, field personnel will be dispatched to the customer's home to give the customer this information in person. If the customer is not at home at that time, then a door hanger will be left providing outage and safety information. Reports that track contact

**** * ******* * ******** * ********* * **** * ** * ******************************* ********* * *
contacted. Additionally, Regional Centers with reverse 911 capabilities will be used to notify these customers about the extended outage as well as provide status updates.

Information Access: Review and implement, as appropriate, text messaging, e-mail, webinars and conference calls to update elected officials, first responders, Community Emergency
******** * ***** * * ***** * **** * ******* * *** * ***** * ******************** * * ***** *
consider use of reverse 911 capabilities.

Education: ******* * ******** * *** * ********* ******************** * ***** * ** * ********** *
****** * * ****** * **** * *********** * ** * *** * *** * ***** ********************

Volunteers: SCE will encourage its employees to join Community Emergency Response
***** * * **** * ** * ***** * *********** * * *********** * ****************** *
******** * ******* * ***** * **** * * * * * *** * *** * * * ****************************** * **
********* * ******** * ** * ********* * *** * **** *

Pole-Loading: Assess available pole-loading calculation software and select optimum
******* * * * ** * ******* * ******** * **** * ** * ************************** * ***** * *** *
*********** * ******* * * **** * **** * *** * ***** * ************************ * ******* * *** *
clarify responsibilities for assuring that in-service poles with new attachments will continue
** * **** * ** * * * * ****** * ******* *

ATTACHMENT J

Excerpt from The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources

The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources

Experience and Prospects

by Meg Gottstein and Lisa Schwartz[1]

Auction-based capacity markets held several years ahead of need — called "forward" capacity markets — are a relatively new approach for addressing resource adequacy in the power sector. Early experience in the United States (US) suggests that these markets have the potential to play a supporting role in delivering capacity from low-carbon, demand-side resources, including energy efficiency. However, auction results to date also suggest that these markets encourage the construction or continued operation of high-emitting supply-side resources to meet reliability targets. Market design improvements and additional policies can serve to better align these capacity markets with carbon reduction goals.

[1] The authors gratefully acknowledge technical assistance from Paul Peterson and Doug Hurley, Synapse Energy Economics, Inc.

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Introduction and Summary

For most of the US power sector's history, the quantity and mix of resources built to meet customer demand for electricity was determined or "planned" by utilities and regulators using a range of analytical tools and methods. The revolution in computing technologies during the 1970s and '80s made possible the development of sophisticated planning models that were used to identify the least-cost mix of resources to meet demand for electricity, given a specified level of reliability. In the mid-1990s – with the emergence of electric industry restructuring in some parts of the US – came the expectation that competitive markets would now determine both the optimal amount and the optimal mix of resources. The result was a move away from involvement of regulators in the planning and procurement of electricity, toward almost exclusive reliance upon markets for deciding how much and what kind of generating capacity would be available to meet customer demand.

Real world experience quickly demonstrated that early market designs were not going to deliver the amount of generating capacity required for reliability needs. Stated another way, these markets were not eliciting sufficient investment in plant capacity to meet resource adequacy requirements. The response in parts of the US was to introduce a regional planning and procurement process into organized power markets[2] to address this shortcoming. Regional system operators, using traditional planning studies, were now tasked with determining the level of capacity needed for resource adequacy several years into the future. They also became responsible for procuring the required amount of capacity by augmenting existing energy markets with a forward looking capacity auction.

More specifically, in these auctions the system operators solicit bids to meet the level of resource commitment they estimate will be needed to meet future peak demand on the system, and then provide market-based revenues to resources that can fulfill that commitment. The revenues take the form of a stream of capacity payments[3] — at a price determined through a regional competitive auction. Only those resources bidding at or under the market clearing price of the auction receive capacity commitments and payments for being available, and for measured and verified performance when called upon, during the expected system peak hours. This particular approach to planning and procurement in the power sector became generally referred to as a "forward capacity market."

Forward capacity markets are a development to watch because they combine traditional planning with organized markets into a unique formula that, based on experience to date in the US, appears to overcome the limitations of earlier energy-only or capacity market designs in meeting resource adequacy needs.[4] More important, they represent the first time that energy efficiency resources have been expressly designed into organized power markets and permitted to compete directly with supply-side power generators.

Demand-Side Resources

Demand-side resources (also referred to as demand resources) are customer-based resources that reduce energy needs at various times of the day and year — across some or many hours. They are generally defined as follows:

1) **Energy efficiency** — installing more efficient equipment or using more efficient processes/ systems to achieve a continuous and permanent reduction in energy use without reducing the quality of service
2) **Demand response** — changing a customer's electricity demand in response to dispatch instructions or price signals
3) **Distributed generation** — generating electricity at the customer site, in some cases using the waste heat produced in the electric generation process to also deliver useful heat or steam (combined heat and power)

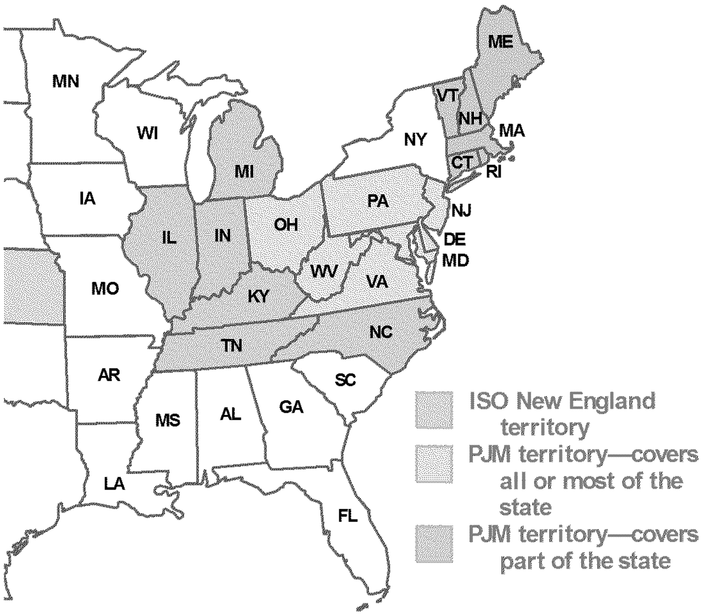
2 "Organized power markets" refers to power markets with an Independent System Operator (ISO) or Regional Transmission Organization (RTO) that operates a regional energy market, capacity market, or both. This paper does not distinguish between RTOs and ISOs — which provide equivalent reliability services — and we refer to these entities generically as regional "system operators" in the following sections.

3 Capacity payments are in US$/megawatt (MW)-day or US$/kilowatt (kW)-month. Conversion: $100/MW-day ≈ $3/kW-month.

4 An overview of that experience is presented above.

Figure 1

ISO New England and PJM Territories



Two organized markets in the US — PJM[5] and ISO New England (ISO-NE)[6] — now conduct forward capacity auctions that permit a wide range of demand-side resources to compete with supply-side resources in meeting the resource adequacy requirements of the region. (See Figure 1 below.) The response of demand-side resources in the PJM and ISO-NE auctions is impressive, and their participation is clearly demonstrating that reducing consumer demand for electricity is functionally equivalent to — and cheaper than — producing power from generating resources for keeping supply and demand in balance. One study suggests that participation of these resources in the first New England auction potentially saved customers as much as $280 million by lowering the price paid to all capacity resources in the market.[7] And in the most recent PJM auction, demand-side resources are credited with reducing the unit clearing price from $178.78 to $16.46 in unconstrained zones — a savings of $162.32/MW- day.[8] Detailed results for the PJM and ISO-NE forward capacity auctions are presented in Appendix 1.

There are two additional capacity markets in the US – one run by the New York ISO and the other (as of June 2009) by the Midwest ISO.[9] However, only PJM and ISO-NE run auctions several years in advance of need and permit energy efficiency along with other demand-side resources to compete with generation to meet future reliability requirements. They also offer the longest track record for forward capacity markets covering multiple states. Brazil is the only other country with a forward capacity market, but it does not permit demand-side resources of any kind to compete.[10] Therefore, our discussion focuses on the forward capacity markets run by PJM and ISO-NE.

This paper examines how auction-based forward capacity markets address resource adequacy, with particular focus on their potential to increase the availability of

[5] PJM Interconnection is an RTO that operates a competitive wholesale electricity market and manages the high-voltage electricty grid for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvaia, Tennessee, Virginia, West Virginia, and the District of Columbia.

[6] ISO-NE oversees New England's bulk electric power system, serving the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[7] Cheryl Jenkins, Chris Neme, and Shawn Enterline, Vermont Energy Investment Corporation (VEIC), "Energy Efficiency as a Resource in the ISO New England Forward Capacity Market," ECEEE 2009 Summer Study Proceedings.

[8] Joseph Bowring, Monitoring Analytics, "Analysis of the 2012/2013 RPM Base Residual Auction," Sept. 10, 2009, Table 20. "Unconstrained" zones do not experience any distribution or transmission bottlenecks for the delivery of electricity to the end-user, whereas "constrained" zones experience such limitations and pay clearing prices that reflect those constraints to capacity available during peak hours in those zones. Accordingly, the reduction in prices due to demand resources for any individual constrained zone will be higher or lower than $162.32 per MW per day for this auction, depending in part on the quantity of demand-side resources located in that zone.

[9] For more information on these capacity markets, see Paul Peterson and Vladlena Sabodash, Synapse Energy Economics, Inc., "Energy Efficiency in Wholesale Markets: ISO-NE, PJM, MISO," ACEEE 5th National Conference — Energy Efficiency as a Resource, Sept. 29, 2009, and New York ISO, "Installed Capacity Manual 4," October 2009.

[10] Sam Newell, Kathleen Spees, and Attila Hajos, The Brattle Group, *Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements*, prepared for the Midwest Independent System Operator, January 2009. http://www.brattle.com/_documents/uploadlibrary/upload832.pdf

demand resources to meet future capacity requirements. However, experience to date also makes a strong case that more is needed in a carbon-constrained world, where the total mix of resources is as important as the total quantity, both in the short- and long-term. In particular, construction and continued operation of high carbon-emitting, supply-side resources dominate the mix of capacity clearing these auctions, and therefore these resources are receiving the bulk of market incentives (capacity payments). The results of recent studies — as well as market experience — also suggest that carbon pricing alone is unlikely to reduce this dominance in forward capacity markets (or in energy-only markets) at the pace or scale required to meet aggressive carbon reduction targets.

In light of these observations, we pose the following question to policymakers: How can the planning and procurement process through forward capacity markets be strengthened to work in concert with carbon reduction goals and policies, rather than at cross purposes? This paper suggests a menu of options that could reduce carbon emissions from the power system by:

- Providing premium capacity payments to low-carbon resources
- Selecting auction winners based on level of carbon emissions as well as bid price
- Making capacity payments only to those resources with low- or zero-carbon emissions
- Phasing out capacity payments to existing, high-emitting resources
- Allowing a longer price commitment or establishing fixed-capacity floor prices for low-carbon resources
- Properly considering energy efficiency in load forecasts that set auction capacity needs
- Refining existing market rules, as needed, to ensure that energy efficiency can fully compete on an equal basis with power generators, including distributed generation[11]

More generally, forward capacity markets create market incentives in the form of capacity payments for resources that can commit to being available at times of system peak, beginning several years into the future. But these capacity payments are clearly not the only factor driving the mix of resources to meet customers' current and future electricity needs. Existing market rules and procurement policies that affect the mix of resources meeting the system's energy requirements — as well as policies and regulations that affect access, location, and cost recovery for transmission and distribution facilities — have enormous impact on both the short- and long-term resource mix in the power sector.

It is beyond the scope of this paper to fully explore how market rules, regulations, and policies can be harmonized and strengthened to meet customers' energy needs reliably in a carbon-constrained world. Nonetheless, we observe that many states in the US, including those where forward capacity markets and carbon pricing currently exist, have made large and long lasting commitments to demand-side and renewable resource procurement through additional policies and regulations. These include:

- Strong energy efficiency codes and equipment standards
- Stable and sustained funding to provide audits, financial incentives, and financing for home and business efficiency improvements, including through carbon auction revenues
- Energy efficiency resource standards that require achievement of specified energy-saving targets
- Renewable energy standards that require meeting a percentage of energy consumption with renewable resources, along with long-term contracting requirements in some cases
- Decoupling of utility profits from revenues, financial incentives for shareholders, or both where the utility is the efficiency portfolio manager — or performance contracting with third-party administrators to deliver comprehensive, large-scale efficiency programs
- Complementary resource planning and procurement practices designed to increase the mix of demand-side and renewable resources that can meet resource adequacy requirements

Finally, we recognize that not all regions will create capacity markets for the purpose of addressing resource

[11] For example, energy efficiency resources that clear the PJM auction cannot receive capacity payments for more than four delivery years, whereas under the ISO-NE market rules these resources are eligible to receive payments over the full life of the installed measures. All other resources are eligible to participate in these capacity markets for as long as their ability to reduce demand or generate power continues.

adequacy needs, and we do not attempt to evaluate in this paper whether they should. The evolution of capacity markets in certain regions of the US has its own, and unique, history. (See text box.) Establishing forward capacity markets and their associated auctions involves complex market rules and a myriad of market design choices along the way, all with major implications for the relative costs and benefits to consumers and resource providers. Options for addressing resource adequacy needs that do not involve the development of a capacity market should also be explored by policymakers, particularly in the context of a carbon-constrained power sector. The starting point of this paper, however, is that such markets already exist (or are in the planning stages). It is within this context that we offer our observations and recommendations.

Resource Adequacy in the US

In the US, resource adequacy refers to the "ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times" — in effect, to provide reliable supply 99.97 percent of the time.[12] This high standard of reliability reflects the unique "serve all, or serve none" nature of the electric system: If it falls short in meeting even one customer's power needs, all customers relying on that electric circuit are literally left "sitting in the dark." Contrast this with other goods and services sold to consumers — for example, milk sold at a grocery store. If there are only 15 cartons of milk on the shelf and 16 customers come in at the same time to purchase milk, only one customer walks away empty handed (and that person could at least find a substitute product at the store to quench his/her thirst). In contrast, if that product were kilowatt-hours, and peak demand (or peak load) exceeds the ability of the system to generate electricity at that time, then the store "shuts down" and all customers walk away empty-handed.

To ensure against such an outcome, utilities and other companies that sell electricity in the US and in many other power markets in the world are obligated to own or purchase enough capacity to reliably meet their customers' peak demands ("loads"). We call them "load-serving entities" or "LSEs," and unless otherwise noted, do not distinguish between regulated LSEs (e.g., distribution utilities) and non-regulated LSEs (retail electricity suppliers). In either case, the LSE's resource obligation in a forward capacity market is expressed in terms of its share of projected capacity needs for the region several years in the future.

An electric system must perform three functions well to ensure resource adequacy — that is, to ensure that there is sufficient capacity committed to meeting customers' peak loads at all times. These are:

1) Estimate when the peak loads are likely to occur and the level of capacity commitment needed to reliably meet them.[13]
2) Obligate LSEs to have sufficient capacity available to them during those projected periods of peak loads.
3) Put policies and rules in place to ensure that sufficient resources will commit capacity to operate (or to reduce loads) during these periods, both in the short- and long-run.

In other words, ensuring resource adequacy involves a planning process (what level of capacity commitment is needed and when?) and a procurement process (how to acquire it?) that focus on the quantity and timing of resources, but not the mix of resources required to meet system reliability. The attribute a resource is required to demonstrate for resource adequacy purposes is that its obligated capacity will be available when called upon, during the projected hours of peak system loads. Resource adequacy rules are indifferent to other attributes, including environmental attributes of resources.

[12] North American Electric Reliability Corporation, Glossary of Terms Used in Reliability Standards, April 20, 2009, at http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf Put another way, resource adequacy means having sufficient electric supply resources in place to maintain the "one day in 10 years" standard of reliability (which translates to reliable supply 99.97 percent of the time). See also N. Jonathan Peress and Kenneth A. Colburn, "Connecting Market Design: From Carbon to Electric Capacity," October 2005, Vol. 3, No. 1, Energy Committee Newsletter, American Bar Association.

[13] The level and timing of peak loads are estimated before the fact, and the projections are less reliable the farther out in time they are made.

How Forward Capacity Markets Evolved in the US[14]

Forward capacity markets in the US evolved as a way of ensuring resource adequacy at reasonable costs to electricity consumers through a combination of system planning and organized markets. Prior to the development of organized markets in parts of the US,[15] power "pools" established a reserve margin requirement and each participating LSE was responsible for acquiring installed capacity to meet its individual loads plus that margin, or face financial penalties. The setting of capacity requirements for the pool as a whole meant, however, that each LSE's reserve requirements were significantly lower than they would otherwise be if it were a stand-alone entity; that is, participants in the pool benefited from the greater diversity of loads and supply resources that characterized the combined system. The pools also facilitated the trading of capacity through bilateral agreements, which had particular value in those pools where individual system peaks were temporally differentiated (as in New England whose northern states peaked in the winter and southern states in the summer). After market restructuring, LSEs also could trade capacity in auctions run by the system operator responsible for the reliability of the region's electric grid. In those early days of competitive wholesale markets, auctions generally were held just a few days before the one-month delivery period.

These nascent capacity markets provided insufficient incentives for plants to be available when called on. The result was "bipolar pricing." If there was a supply surplus, capacity prices were effectively zero. If there was any shortfall, capacity prices rose to the price cap (if any). Moreover, short time horizons for the auctions limited offers for new capacity. In addition, market power[16] concerns surfaced after utilities sold their power plants under electric industry restructuring, particularly in areas with significant transmission constraints. The Federal Energy Regulatory Commission (FERC) responded with price caps for the energy market that, as a side effect, limited scarcity price signals. Thus, "energy-only" power markets — that is, markets that pay clearing prices for energy on a day-ahead or shorter basis — were not paying high enough prices for investors to build sufficient peaking resources to meet future reliability needs.

Meanwhile, merchant generators were buckling under high fuel prices for new natural gas-fired plants, and owners of older, less efficient plants filed requests for retirement. To maintain system reliability, federal regulators approved expensive "reliability must-run" contracts to keep needed plants going and then mandated the development of a more systematic approach for paying for capacity. The resulting process produced a mechanism to make capacity payments to all generators, not just those applying for retirement, and to develop more efficient capacity where it was most needed. But the high price tag of such contracts for the New England states led to legal action that ended with a novel settlement in 2006: a capacity market run by ISO-NE that allows energy efficiency and other demand-side resources to compete with generation to meet reliability requirements several years in advance of need. In 2007, much of the Mid-Atlantic and Midwest region adopted a similar capacity market run by PJM.

[14] This description draws upon Robert Stoddard and Seabron Adamson, CRA International, "Comparing Capacity Market and Payment Designs for Ensuring Supply Adequacy," Proceedings of the 42nd Hawaii International Conference on System Sciences, 2009, and Sandra Levine, Doug Hurley, and Seth Kaplan, "Prime Time for Efficiency," *Public Utilities Fortnightly*, June 2008.

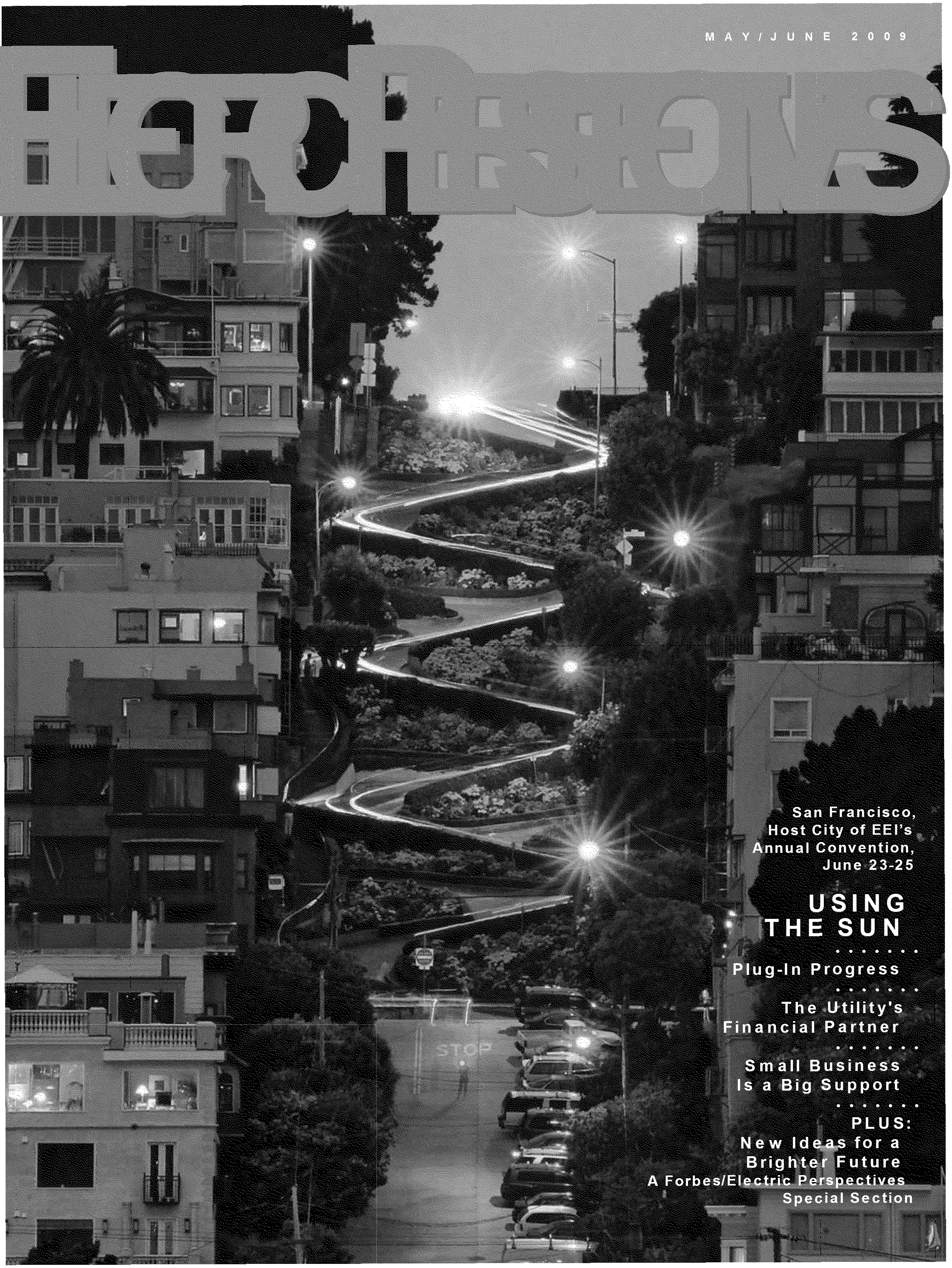
[15] See footnote 2 for a definition of "organized markets." Southern and western states, except for California, have not developed organized power markets.

[16] Such as withholding power to extract higher prices.

ATTACHMENT K

Article: Selling Energy Efficiency

MAY/JUNE 2009



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ATTACHMENT L

Excerpt from SCE's Annual System Reliability Report – 2011

Southern California Edison
Annual System Reliability Report - 2011
Table of Contents

Attachment	Tab Name	Description
1A	Historical System Indices (IEEE Std 1366-2003)	SAIDI, SAIFI, and MAIFI Annual System Statistics calculated per IEEE-1366.
1B	Historical System Indices (D.96-09-045)	SAIDI, SAIFI, and MAIFI Annual System Statistics calculated per D.96-09-045.
1C	Major Event Days Detail	For each excluded major event day, the date & primary cause, the associated SAIDI, SAIFI and MAIFI and the basis for the exclusion (either the D96-09-045 definition or IEEE Std 1366-2003 2.5 Beta Method).
2	List > 12 Sustained	Circuit ID and number of customers experiencing more than one sustained outage per month on a rolling annual average basis after exclusion of major events (2002-2011)
3	Top 10 SAIDI Each Year	The largest SAIDI days each year, the number of customers affected, and the number of people used to restore service (2002-2011)
4	No Service by Hourly Interval	The number of customers without service by hourly interval (2002-2011) for each major event day.
5	No Service by Duration	The number of customers without service by outage duration (2002-2011) for each major event day.

Southern California Edison

Historical System Reliability (CPUC D.96-09-045)

2002 - 2004 Using DTOM

2005 Using DTOM & ODRM

2006 - 2011 Using ODRM

	All Interruptions Included[1]			Major Event Days Excluded Per D.96-09-045[2]		
YEAR	SAIDI[3]	SAIFI	MAIFI	SAIDI[3]	SAIFI	MAIFI
2002	52.75	1.23	1.11	50.44	1.11	1.10
2003 (w/o sub)[5]	87.23	1.39	1.37	63.90	1.19	1.17
2003 (w/ sub)	79.20	1.35	1.37	57.78	1.15	1.18
2004 (w/o sub)	75.21	1.34	1.19	67.11	1.26	1.12
2004 (w/ sub)	68.39	1.30	1.19	62.83	1.24	1.13
2005 (w/o sub)	91.64	1.52	1.44	74.25	1.27	1.21
2005 (w/ sub)	91.45	1.52	1.44	74.16	1.27	1.21
2005 (ODRM)[4]	106.41	1.02	2.00	82.10	0.82	1.67
2006 ODRM	142.27	1.08	1.81	116.34	1.00	1.64
2007 ODRM	151.60	1.15	1.68	141.95	1.11	1.60
2008 ODRM	119.21	1.12	1.67	119.21	1.12	1.67
2009 ODRM	105.98	0.94	1.41	105.98	0.94	1.41
2010 ODRM	141.14	1.09	1.64	141.14	1.09	1.64
2011 ODRM	232.60	1.08	1.49	173.03	1.03	1.43

All calculations utilize a definition of "sustained" interruption as described in D.96-09-045, which is an interruption lasting 5 minutes or longer.

[1] This excludes ISO-directed firm load curtailment, Protective Outage Plan (POP) outages, Remedial Action Scheme (RAS) outages.
[2] Major Event Exclusions are defined in D.96-09-045 under Appendix A Section I - Item 4c.
[3] Metrics for 1999 - 2005 have been adjusted upward to reflect the variance introduced by Southern California Edison's former convention of declaring All Load Up (ALU) when power had been restored up to the last residential transformer. An estimate was added to the annual CMI base to arrive at the normalized SAIDIs. No adjustment was necessary beyond 2005.
[4] ODRM data in 2005 only does not include Area Outages.
[5] "Sub" refers to substitution of historical average metrics in circuits affected by the Bark Beetle Infestation.