Natural Resources Defense Council

Comments to the Arizona Corporation Commission

July 15, 2013

Re: Generic Docket Number E-00000W-13-0135/ In the Matter of the Commission's Inquiry into Retail Electric Competition

Introduction:

The evidence from states with retail competition suggests that direct access may not lower prices, accelerate innovation, or provide meaningful new products and services. Furthermore, the electric service provider (ESP) business model – with its short-term focus – may not effectively support investments in new generation capacity, renewable energy sources, and in the public interest.

There are huge potential risks and uncertain benefits to customers from a transition to retail competition including price increase and lack of certainty over responsibility for reliable service. In addition, nearly every existing energy policy would have to be addressed to ensure the new market structure would not undermine or confuse compliance by all market entrants. Without fully vetting the effects of a retail competition structure, customers could be left confused, mislead or subject to abuse and fraud, or unreliable service.

The Commission would be better served ensuring that utilities provide reliable, low cost service at the lowest environmental impact. The current resource portfolio of most Arizona utilities is neither lowest cost nor lowest risk for consumers. With a heavy reliance on coal, Arizona utilities are causing significant environmental and societal costs borne by all Arizonans. Furthermore, coal exposes utilities and their customers to significant financial and regulatory risk. A better resource mix is possible if disincentives for energy efficiency are fully addressed and utilities financial health are aligned with resource portfolios that provide clean, reliable and low cost service. However, there is no significant evidence that retail competition will reduce risks for customers, ensure provision of reliable service, meet Arizona's electricity policies or lower prices.

We provide short answers to some of the questions below. Many of our answers are limited as we lack information on the market structure being contemplated by the Commission.

Retail Competition the answer depends heavily on the specific market and regulatory structure contemplated.

We have also provided three attached references. Two discuss the impacts of retail competition: one focused on the unmet promise of reduced prices and another on the impacts of retail restructuring in California. The third piece discusses the role of credit-worthy distribution utilities in selecting low cost resource portfolios.

1) Will retail electric competition reduce rates for all classes of customers- residential, small business, large business and industrial classes?

Unfavorable price performance in restructured states has been caused to some extent by increases in generation fuel costs such as natural gas. States that restructure are typically higher price states pre-restructuring, often because they rely on such fuels more heavily than do other states. However, while fuel costs do account for some of the disparities in retail prices between restructured and non-restructured states, market structure may also play a role in price hikes.

Dr. Kenneth Rose cautions that when it comes to explaining unfavorable price performance in restructured states, "the story is more complex than simply attributing the increases to the costs of fuels used to generate power."[1] For example, at the retail level, suppliers of full requirements retail service add costs and risks not directly related to costs of energy.

Disentangling these costs and risks as components of rates is difficult, so Rose's conclusions are only tenuous,[2] but his analysis suggests that the retail competition market structure may itself contribute to higher retail electricity rates. In restructured states, default service providers typically purchase their electricity at market rates under short-term contracts (1-3 years) rather than building a portfolio of long-term resources under cost-of-service ratemaking. As a result, default service prices do not capture the hedging value of long-term commitments, are subject to significant year-to-year volatility, and force customers to pay premiums associated with market-based rates (unless they have a price cap). When wholesale markets become volatile, the consequences can be severe for default service providers. For example, during the California energy crisis:

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[1] KENNETH ROSE, THE IMPACT OF FUEL COSTS ON ELECTRIC POWER PRICES 21 (June 2007), *available at* http://www.appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf.
[2] *Id.* at 17-18.

> ESPs had the incentive to "return" customers to the utilities, which meant more loss-inducing sales. An ESP with a forward contract to provide power to a customer at, say, $40/mwh could "buy out" the contract by paying the customer the difference between the retail price faced when buying from a utility at $65 [the capped retail rate for IOUs] and the contractual price of $40. The ESP could then that now available megawatt-hour and sell it in the spot market for hundreds of dollars.[3]

During periods of volatility, ESPs have been known to dump their customers back to default service as an alternative to honoring their contractual obligations – as, for example, Enron was alleged to have done in a lawsuit by the Regents of the University of California and Board of Trustees of California State University.[4] Adding new customers to default service in a period of wholesale market dysfunction only increases the pressure on retail prices, or to the default provider in the case of price caps.

Also, generation fuel cost spikes may occasion abuse by major suppliers in states where restructured retail markets are not fully competitive. In Texas, for example, many worried that under the "price-to-beat" structure major suppliers like TXU reaped windfall profits thanks to surges in natural gas prices. In October 2006, the *Wall Street Journal* reported that Texans were paying twice the national average for electricity, with little hope for relief in sight: Texas law did not require suppliers to lower rates when natural gas prices fell and the market was insufficiently competitive to discipline big suppliers like TXU.[5] Electricity prices, as a result, "did not adjust down when natural gas prices fell."[6]

Professor John Kwoka reviewed twelve such major studies, nine of which give favorable assessments of retail competition. Of those nine, seven are either consulting reports[7] or internal

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[3] W. KIP VISCUSI ET AL., ECONOMICS OF REGULATION AND ANTITRUST 460 (4th ed. 2005).

[4] The UC/CSU filed suit against Enron for breach of direct access contracts to provide universities with electric power, causing service default to utilities, with ultimate cost for electric power borne by DWR. The parties eventually settled, with Enron returning the Universities to direct access status. Bill Lockyer, A LAW ENFORCEMENT PERSPECTIVE ON THE CALIFORNIA ENERGY CRISIS: RECOMMENDATIONS FOR IMPROVING ENFORCEMENT AND PROTECTING CONSUMERS IN DEREGULATED ENERGY MARKETS 83 (2004), *available at* http://ag.ca.gov/publications/energywhitepaper.pdf.

[5] Rebecca Smith, *In Texas Energy Deregulation, Top Company is a Big Winner: TXU, Other Suppliers Keep Rates Up as State Adviser Sees Possible Manipulation*, WALL ST. J., Oct. 27, 2006, at A1.

[6] Taylor and Van Doren, *supra* note 29.

[7] Authored by Center for Advancement of Energy Markets, Synapse Energy Markets, Global Energy Decisions, Energy Security Analysis, Inc., Cambridge Energy Research Associates.

evaluations (by the New York Department of Public Service and ISO/RTO Council). The remaining five are academic studies, three of which offer negative overall assessments.[8] His review finds that, due to serious methodological flaws in many of the studies, there is "no reliable and convincing evidence that consumers are better off as a result of restructuring of the U.S. electric power industry."[9]

Considerable doubt now exists as to whether competition *can* develop for all customer classes at all. The participation rates among residential customers are almost uniformly tiny. Large, non-residential customers have switched in much higher proportions than residential and small non-residential customers. In 2004, among retail access states, average statewide retail access penetration for non-residential customers ranged from 15-62%, while it was generally still less than 10% for residential classes (which usually represent 90% of all customers and 30-40% of total load).[10] That year, only 4.4% of all U.S. electricity customers received their power from power marketers.[11] In 2006, only four states – Massachusetts, New York, Ohio, and Texas – had more than 5% of residential load served by competitive suppliers.[12] Many restructured states remain at or near zero percent. At its peak in early 2000, only 2.25% of residential customers were served by direct access providers in California. The vast majority of these customers switched to "green" ESPs which often sold power more cheaply due to the availability of direct subsidies ("customer credits") paid by all utility billpayers.

One reason most residential customers may never benefit from direct access is that it is simply not profitable enough for alternative suppliers to compete for their business. The margins at stake with small customers are often too low to attract competitors: the marketing and transaction costs alone for serving small customers have been estimated at 1 cent per kWh.[13]

[8] Note, of course, that Kwoka's study was itself prepared for the American Public Power Association. JOHN KWOKA, RESTRUCTURING THE U.S. ELECTRIC POWER SECTOR: A REVIEW OF RECENT STUDIES (2006), *available at* http://www.appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf.

[9] Of the five studies authored by academics (as opposed to consultants or internal reviews), three gave negative assessments of restructuring, while two favored it. Kwoka, *supra* note 8, at vii.

[10] Pfeifenberger et al., *Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service*, ELECTRICITY J., Dec. 2004, at 50-64.

[11] Task Force 2007, *supra* note **Error! Bookmark not defined.**, at 14.

[12] Kenneth Rose and Karl Meeusen, 2006 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS, at 14, *available at* http://www.ipu.msu.edu/research/pdfs/2006_rose_1.pdf.

[13] HARRINGTON ET AL., THE REGULATORY ASSISTANCE PROJECT, PORTFOLIO MANAGEMENT (July 2002) *available at* http://raponline.org/showpdf.asp?PDF_URL=%22Pubs/PortfolioManagement/PortfolioMgmtReport.pdf%22.

There is "little room for efficiency gains (and therefore vigorous price competition)."[14] As Pennsylvania's Consumer Advocate observed in testimony to the legislature:

> [T]he common assumption was that wholesale competition would drive down the cost of generation and that most customers would switch to retail competitors who would offer service at lower prices than the incumbent utilities. What we know now, however, is that the provider of last resort service has been, and is likely to continue to be, the *predominant service* -- at least for residential customers -- for the foreseeable future.[15] (emphasis added)

Also troubling is a study published in the *Electricity Journal* finding that in restructured states, utilities disproportionately allocate fixed and common costs to residential customers, whose price elasticity of demand is less sensitive than commercial and industrial customers. This phenomenon occurs at a higher rate in retail choice states than in franchise states.[16]

The purported benefits of retail competition thus do not, and probably will not, flow equally to all customer classes. In fact its advocates, participants and beneficiaries are principally large customers. For the residential customers who represent the bulk of customers direct access appears to offer very little.

Yet even the benefits to industrial and large commercial customers have been questioned. In theory, industrial and large commercial customers stand to gain the most, because they have the sophistication, information, and understanding of and appetite for risk/price management. Focusing on retail prices for industrial customers may provide the most helpful analysis of retail competition to date. The rate freeze problem does not apply as cleanly to this customer class as the others, for two reasons. First, unlike their smaller customer counterparts, industrial customers were often not subject to post-restructuring mandated price caps.[17] Second, as large, sophisticated market players, they were anticipated to be the primary beneficiaries of retail competition. One would thus expect evidence that at least *this* customer class has thrived.

In fact the evidence suggests otherwise. In his 2005 study, Professor Jay Apt found no

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[14] Blumsack et al., *Lessons From the Failure of U.S. Electricity Restructuring*, ELECTRICITY J., March 2006, at 25.
[15] Testimony of Sonny Popowsky, Consumer Advocate of Pennsylvania, Before the Senate Environmental Resources and Energy and Consumer Protection and Professional Licensure Committees, (June 5, 2007), *available at* http://www.oca.state.pa.us/tmony/test.htm.
[16] John A. Sautter, *Where Have All the Benefits Gone? Cost Allocation Toward Residential Ratepayers in Restructured Electricity Markets*, ELECTRICITY J., March 2007, at 41. As of mid-September 2007, no one had challenged Sautter's claim.
[17] Task Force 2007, supra note **Error! Bookmark not defined.**, at 92.

correlation between restructuring and improvement to the annual rate of change in price.[18] Another study found that "[t]he data show that prices for industrial customers, who were expected to be the principal beneficiaries, have no statistically significant differences between restructured and un-restructured states."[19] In another analysis, Professor Mark Fagan concludes that over a narrower period (2001-2003), average industrial prices (adjusted for "competition transition charges") were 1.3 percent above predicted levels in restructured states while they were 9.2 percent above predicted levels in non-restructured states. But in Fagan's analysis, "neither regulatory reform at the retail level (restructuring status) nor at the wholesale level (RTO participation) is a significant driver of the restructured states' superior price performance."[20] Taber's independent econometric study came to a similar conclusion, finding "no evidence to support the general expectation that deregulation would result in lower electricity prices."[21] Even the Electricity Consumers Research Council (ELCON), an association of large industrial electricity users and major force behind retail competition in the 1990s, criticized competitive retail markets.[22]

2) In addition to the possibility of reduced rates, identify any and all specific benefits of retail electric competition for each customer class.

An *Electricity Journal* study by Apt, Lave, and Blumsack answers the question, "Did restructuring speed innovation?" succinctly: due to the pressure to lower costs in competitive states, R&D budgets have suffered, and thus "there has been less opportunity for innovation and introducing new technologies in restructured states."[23]

[18] Jay Apt, *Competition Has Not Lowered U.S. Industrial Electricity Prices*, ELECTRICITY J., March 2005, at 52-61.
[19] Blumsack et al., *supra* note 14, at 29.
[20] Mark Fagan, *Measuring and Explaining Electricity Price Changes in Restructured States*, Regulatory Policy Program Working Paper RPP-2006-02, Mossavar-Rahmani Center for Business and Government: John F. Kennedy School of Government, Harvard University (June 2006), at 10, *available at* http://www.ksg.harvard.edu/m-rcbg/research/rpp/RPP-2006-02.pdf.
[21] Taber, Chapman & Mount, *Examining the Effects of Deregulation on Retail Electricity Prices*, Cornell University Department of Applied Economics and Management Working Paper 2005-14 (2006), at 45, *available at* http://aem.cornell.edu/research/researchpdf/wp0514.pdf.
[22] ELCON released several statements complaining that it has "not seen true competition" and "[t]his is not the world ELCON envisioned when we embarked on this road 15 or 20 years ago." See, e.g., Statement of John Anderson, President of the Electricity Consumers Resource Council (ELCON) at the Press Conference on the Joint Filing of Electricity Customers, December 17, 2007, *available at* http://www.elcon.org/press_release.htm.
[23] Lave et al., *Deregulation/Restructuring Part I: Reregulation Will Not Fix the Problems*, ELECTRICITY J., Oct. 2007, at 16.

The Task Force found that among profiled states competition "has not developed as expected for all customer classes" – and there are generally more choices in suppliers and services for commercial and industrial than residential, in part because the former usually do not have option to take POLR service at discounted, regulated rates.[24] In Massachusetts, the Task Force reported over 20 direct suppliers serving C & I customers, along with 50+ licensed electricity brokers or marketers; for residential customers there were but four active suppliers, even though it is one of 4 states where more than 5% residential load was served by competitive suppliers in 2006. New Jersey C & I customers have nearly 20 suppliers, while residential customers have only one or two. In Texas and New York, residential customers have more options – 15 in Texas, between 6 and 9 in each New York service territory.

3) How can the benefits of competition apply to all customer classes equally or equitably?

See the answer to Question 2, above. This question assumes significant benefits. We see no reason to justify this assumption.

4) Please identify the risks of retail electric competition to residential ratepayers and to the other customer classes. What entity, if any, would be the provider of last resort?

Risks include: higher prices; price spikes and reliability failures from lack of appropriate infrastructure and supply investment; consumer confusion; inadequate compliance with existing Arizona energy policies; including energy efficiency and renewable energy investment; customer investment paralysis resulting from ongoing price and market uncertainty.

While a provider of last resort might ensure customers can get reliable electricity from somewhere, it by no means ensures low cost provision. The costs of such a provider would inevitably be higher than other providers, to ensure adequate energy supply for all customers, and the costs of this insurance would have to be spread across customers. A provider of last resort does not protect against the confusion, fraud and abuse possible by misleading market entrants, nor does it ensure all market participants comply with existing Arizona energy laws and policies.

5) How can the Commission guarantee that there would be no market structure abuses and/or market manipulation in the transition to and implementation of retail electric competition?

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[24] Task Force 2007, *supra* note **Error! Bookmark not defined.**, at 92.

Such a guarantee would be difficult and would require significant analysis of market and regulatory structure alternatives.

6) What, if any, features, entities or mechanisms must be in place in order for there to be an effective and efficient market structure for retail electric competition? How long would it take to implement these features, entities, or mechanisms?

The Commission appears to be considering a full reevaluation and reinvention of its existing market and regulatory structure. We would recommend a complete analysis of every policy and consumer protection to ensure any new proposed market structure meets or exceeds the performance of the current system at a comparable or lower cost. As companies compete on price in a competitive retail market, they are not necessarily incentivized to maintain reliability or provide the services customers and the regulator may expect. These new incentives should be fully evaluated before the Commission moves forward.

7) Will retail electric competition require the divestiture of generation assets by regulated electric utilities? How would FERC regulation of these facilities be affected?

We have no comment at this time.

8) What are the costs of the transition to retail electric competition, how should those costs be quantified, and who should bear them?

The costs will vary depending on the market structure and timing. The Commission should ensure that customers are protected from these costs. In many states transition has proven expensive and controversial: As part of the retail restructuring process, states typically mandated some form of "default service provider" or "Provider of Last Resort" (POLR) for customers who could not, or chose not to, receive generation service from an alternative supplier. During the transition periods, these POLRs must provide service under frozen or capped rates; usually, however, the caps applied only to residential customers.[25] These periods often last five or more years, and presumably Arizona would face a similar wait for a restructured market to deliver on its promises.

[25] Thus, some argue, price data about larger customer groups may provide the most instructive price data available at this time. For more on this point, see Section IV.c.ii, *infra* at 10, which suggests that restructuring may have no impact on the annual rate of change in price for large customer classes.

In its 2007 report to Congress, for example, the Electric Energy Market Competition Task Force ("Task Force") [26] found that, generally, few alternative suppliers serve residential customers, and where multiple suppliers exist, "prices have not decreased as expected, and the range of new options and services often is limited." The report notes that in many states below-market capped POLR service is prohibiting entry of alternative suppliers and development of fully competitive retail markets. Among 7 profiled states (IL, MD, MA, NJ, NY, PA, TX), competition "has not developed as expected for all customer classes."[27]

However, as a practical matter, in several states lifting the caps caused considerable turmoil and popular backlash.[28] In 2007, headline-grabbing rate increases in Maryland (50% in Baltimore) and Illinois (24% in Chicago) occurred because the period of regulated prices ended while underlying prices of the fuels used for generation (coal and natural gas) rose significantly.[29] In response to Illinois' electric rate increases, Governor Rod Blagojevich signed legislation providing $1 billion in rate relief to customers, eliminating the auction process, and establishing the Illinois Power Agency to stabilize electric rates.[30] Whether caps/freezes were adopted in genuine anticipation of falling market prices, or to make restructuring politically palatable to constituents (or both), is open to debate. Either way, since deregulation *was* promised as a strategy for lowering rates, lifting the caps in the face of rate spikes has become a real concern for many customers and, in turn, their elected officials.

9) Will retail electric competition impact reliability? Why or why not?

The California experiment with retail competition makes clear that retail competition certainly can negatively affect reliability. Market entrants do not necessarily have sufficient

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[26] The Task Force was established under Section 1815 of the Energy Policy Act of 2005 "to study and report on competition in wholesale and retail electricity markets in the United States." Its five appointed members came from the Department of Justice, Federal Energy Regulatory Commission, Federal Trade Commission, Department of Energy, and the Rural Utilities Service. *See generally* http://www.usda.gov/rus/electric/competition/index.htm.

[27] Task Force 2007, *supra* note **Error! Bookmark not defined.** at 91.

[28] *See, e.g.*, David Cay Johnston, *A New Push to Regulate Power Costs*, N.Y. TIMES, Sept. 4, 2007 ("The combination of higher and faster-rising prices has outraged individual consumers and small businesses and prompted big electric customers to fight back on political, regulatory and legal fronts. 'It is fair to say that in the states that did restructure, we are on the defensive,' said John Shelk, president of the Electric Power Supply Association, which represents owners of competitive power plants.").

[29] Jerry Taylor and Peter Van Doren, Commentary, *Short-Circuited*, WALL ST. J., Aug. 30, 2007, at A11.

[30] Governor's Press Release, Aug. 28, 2007, available at http://www.illinois.gov/PressReleases/ShowPressRelease.cfm?SubjectID=3&RecNum=6205.

customer certainty to make long term infrastructure and reliability investments. Price based competition incentivizes minimizing long term investments. Lastly, retail market entrants can be more susceptible to wholesale market manipulation. This combination can lead to significant reliability impacts.

ESPs operate on short timelines. One problem with short positions is that they are vulnerable to wholesale price fluctuations. If spot market prices are low enough, utilities can be under-sold by ESPs – all the while, of course, utilities pay the long-term infrastructure costs that provide benefits to the whole system. But if wholesale prices spike too dramatically, ESPs can dump customers back onto the utility, as mentioned already.

In the mid-1990s, it was widely believed that merchant power could be financed and built under market conditions. But that view has not come to fruition. Since the California energy crisis, there appears to be little interest in financing generation without a long-term commitment. According to Blumsack et al., the increased risk in relying on the merchant sector has raised the costs of infrastructure, and is reflected among investors. The financial community lends to "system-financed investments" at lower interest rates than "project financing." "Equities markets have not been kind to deregulated utilities or the merchant sector…"[31]

10) What are the issues relating to balancing area authorities, transmission planning, and control areas which must be addressed as part of a transition to retail electric competition?

There are a many potential issues depending on the market design. We have no additional comment at this time.

11) Among the states that have transitioned to retail electric competition, which model best promotes the public interest for Arizonans? Which model should be avoided?

The December 2007 *Electricity Journal* reports that while the principles of retail competition remain appealing in the abstract, "the reality has been mildly to totally disappointing." "[A] handful of states have returned to the old regulatory regime or are seriously thinking doing so."[32] One in three regulators in deregulated states said that "they are now seriously considering re-regulating utilities in their jurisdictions," according to the 2007 Survey of State Utility Regulators carried out by Standard & Poor's and RKS Consulting. Moreover,

[31] Blumsack et al., *supra* note 14, at 23.
[32] *Mich. Is Among States Ready to Turn Back Deregulation Clock*, ELECTRICITY J., Dec. 2007, at 8-9.

when asked to name the states "operating the most successful deregulated energy markets," the most popular response (one in three) was "none."[33]

It is appropriate to recall a fundamental difference between wholesale and retail electricity markets.[34] In wholesale markets, entities purchase and sell power for resale with the overall goal of minimizing bulk power costs. In retail markets, on the other hand, where power is sold to end-users, the emphasis is on the quality and quantity of energy *services* rather than minimizing the price per kilowatt-hour of bulk power. The desirability of competition in the wholesale market is, or can be, a wholly separate question from whether it is necessary or appropriate in the retail sector.

As the CPUC has observed, "[f]or its first two years of operation in the late 1990s, California's restructured markets worked reasonably well."[35] But "calamity struck" in 2000 and 2001, when a number of factors combined to bring the state to financial crisis: unusually high prices in natural gas and wholesale electricity; an over-stressed power grid; possible anti-competitive behavior by market participants; and the state's reliance on short-term wholesale spot markets for most of its load.[36] The West's two largest electricity distribution companies, PG&E and Southern California Edison, incurred massive losses because of the gap between wholesale electricity prices and state-frozen retail rates.[37] The California crisis must factor heavily into any consideration of retail competition.

12) How have retail rates been affected in states that have implemented retail electric competition?

See answer to question 1.

13) Is retail electric competition viable in Arizona in light of the Court of Appeals' decision in *Phelps Dodge Cop. v. Ariz. Elec. Power Coop.*,207 Ariz. *95*, 83 P.3d 573 (App. 2004)? Are there other legal impediments to the transition to and/or implementation of retail electric competition?

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[33] RKS Research and Consulting, Press Release, *Fifth National Study Finds Major Shifts in Opinion & Priorities; Energy Efficiency, Nuclear Gain Support While Coal-Fired Generation Proves Divisive* (Sep. 20, 2007), *available at* http://www.rksresearch.com/changecourse.html.

[34] For a helpful discussion, see RALPH CAVANAGH, THE GREAT "RETAIL WHEELING" ILLUSION – AND MORE PRODUCTIVE ENERGY FUTURES, Natural Resources Defense Council (March 1994).

[35] *Id.* at 6.

[36] Ralph Cavanagh, *Revisiting "the Genius of the Marketplace": Cures for the Western Electricity and Natural Gas Crises*, ELECTRICITY J., June 2001, at 13.

[37] *Id.* at 12.

No Comment at this time.

14) Is retail electric competition compatible with the Commission's Renewable Energy Standard that requires Arizona's utilities serve at least 15% of their retail loads with renewable energy by 2025? (See A.A.C. R14-2-1801 et seq.)

Any market design for retail completion would have to require all market entrants to comply with all aspects of this standard. This could prove difficult given the short term market focus ESPs without a known customer base. As discussed above, ESPs often have a harder time making long term investments and financial commitments. This concern could certainly affect their willingness to comply with a renewable portfolio standard.

15) Is retail electric competition compatible with the Commission's Energy Efficiency Standard that requires Arizona electric utilities to achieve a 22% reduction in retail energy sales by consumption by 2020? (See A.A.C. R14-2-2401 et seq.)

Funding and administering this standard would be significantly more complicated under retail completion. Market entrants would not have a secure customer base or service territory and would likely have harder time successfully implementing energy efficiency. Furthermore, market entrants would likely be incentivized to maximize sales and therefore would have an incentive to avoid cost effective energy efficiency investments.

Retail competition has hampered energy efficiency programs across the country. In the early years of restructuring, funding nationwide decreased dramatically for ratepayer-funded electric energy efficiency programs. In nominal dollars, it decreased from about $1.8 billion in 1993 to just $900 million in 1998.[38] Demand side management was seen as unnecessary in competitive retail markets; pricing and the market would guide customer choices about efficiency. The Task Force notes that "in some instances, retail competition has discouraged these traditional types of programs [demand response], particularly when distributing utilities are no longer responsible for POLR service," citing as an example Pepco ceasing its air-conditioner direct load program when it divested its generation assets.[39] Funding rebounded reaching $1.35 billion in 2003, as states adopted public benefits programs and other means of supporting energy

[38] AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY, 3RD NATIONAL SCORECARD ON UTILITY AND PUBLIC BENEFITS ENERGY EFFICIENCY PROGRAMS: A NATIONAL REVIEW AND UPDATE OF STATE-LEVEL ACTIVITY 1 (Oct. 2005), *available at* www.aceee.org.
[39] Task Force 2007, *supra* note **Error! Bookmark not defined.**, at 97.

efficiency based on non-bypassable surcharges on electric rates – particularly in the wake of the California energy crisis.[40]

16) How should the Commission address net metering rates in a competitive market?

Net metering policy requirements should apply to all market participants. A full evaluation of the effect of such a reform should be included in this docket. Solar energy is remarkable popular and effective in Arizona, and retail competition and the associated rate and policy uncertainty could make it more difficult for customers to assess the viability of investment in solar.

17) What impact will retail electric competition have on resource planning?

Retail Competition can make it very hard for a market entrant to successfully implement long term plans for necessary resources. As a result short term purchases are more likely and market manipulation can be a bigger risk. Furthermore, low cost additions, including energy efficiency, can be harder to integrate without a territorial customer base. See attachment X for more discussion of this issue.

18) How will retail electric competition affect public power utilities, cooperatives and federal controlled transmission systems?

No Comment at this time.

Submitted,

July 15, 2013

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[40] *Id.*

Attachment 1:
State Retail Electricity Markets:
How Are They Performing So Far?
By Kenneth Rose

State Retail Electricity Markets: How Are They Performing So Far?

States that restructured their electricity market to separate power generation from other retail services did so in part to create competition and bring their generally higher power prices down. The move has not produced the desired result.

by Kenneth Rose

One of Justice Brandeis' more memorable quotes was from a 1932 dissent, in which he stated that "a single courageous State may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country." While states do not necessarily start out to perform an experiment so much as change public policy, 13 states and the District of Columbia did decide to restructure the electricity market in their jurisdictions, separating generation from retail electricity service and allowing retail customers access to a variety of service suppliers. More than twice as many states – 30 in all – chose not to do so.[1,2]

Kenneth Rose *is an independent consultant and a Senior Fellow with the Institute of Public Utilities at Michigan State University. Dr. Rose is a nationally recognized expert with more than 28 years of research experience on the structure, economics, and regulation of the US electric supply industry. He was a Senior Institute Economist at The National Regulatory Research Institute at Ohio State University from 1989 to 2002 and a lecturer for the School of Public Policy and Management and the John Glenn School of Public Affairs at OSU. Dr. Rose received his Ph.D. degree in Economics from the University of Illinois at Chicago.*

[1] The term "retail access" is used in this article to mean allowing an end-use retail customer to pick their own supplier, or having the statutory and regulatory means to pick a power supplier. Whether an actual offer is available to retail customers is another matter.

[2] Of the remaining seven states, three have limited retail access to larger customers or to a percent of sales (Michigan, Montana, and Virginia), one (Arizona) regulates the retail price, and one (California) suspended retail access. Also, Alaska

This has been the status for quite some time now, with no state having passed legislation to begin retail access since 2000, and even a few states having pulled back from it in the aftermath of the California/Western power crisis of more than a decade ago. Most of the states that adopted retail access have now finished their transition periods, during which previously regulated residential rates were usually discounted and capped for a number of years. Since the caps have expired, the residential retail customers are now paying a market-based price for electricity, either from a supplier they chose or based on a default rate determined in an auction process or by some other market means.

A principal motivation for retail access legislation was that states with high electricity prices relative to other states and the national average were hoping to lower their prices. Large industrial customers were the group most actively seeking retail access, but clearly residential customers were expected to benefit as well, or so it was hoped.

The main question addressed here is, how are the customers in retail access states faring relative to those in states that remained regulated; specifically, how have residential customers fared? Or put another way, have the retail access states closed the gap with the lower-cost states that, with a few exceptions, did not adopt retail access?

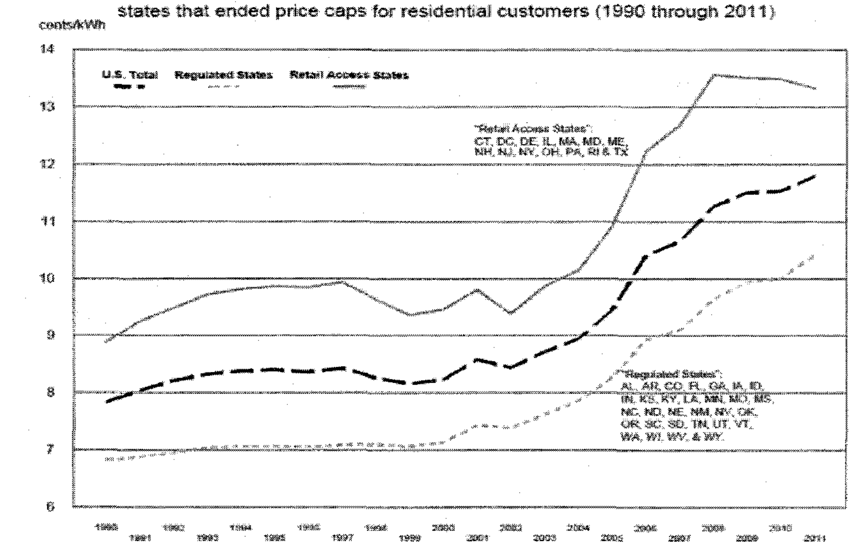
To shed some light on this question, we need to look at how electricity retail prices have changed over the last 20 years. The data used here is from the U.S. Department of Energy, Energy Information Administration (EIA). This provides a reliable and consistent time series to examine and is widely used for these reasons. However, there are several limitations to using this data series. First, the data is state level, so any variation within the state between utilities will be missed. Second, it includes all utilities in the state including those that either may not be regulated or not required to allow retail access (such as public power utilities). Third, the rates or prices are the total bundled average revenue per kilowatt-hour (kWh).[3] This is the total average price that includes generation, transmission, distribution, , and other customer charges; however, the generation portion is the only part of the price that is subject to potential competition. Since there is no consistent data source of generation-only prices, this is the best data currently available and likely the reason that the EIA data is most often used by those who want to track state-level utility prices. While this EIA data includes commercial and industrial customers, only the residential customer class is addressed here.

and Hawaii have not pursued retail access. All seven of these states, therefore, do not fit precisely into either category of "retail access" state or "regulated" state.

[3] The price is calculated by dividing the total state revenue for the year (total dollars for each customer class) by the respective customer sales (total kWh sold for that state and year).

Figure 1 shows the weighted average price for residential customers for all states, the 14 jurisdictions with retail access, and the 30 states that are regulated. Prices on the left side of the chart begin with 1990 prices and show the price gap that already existed between these groups of states years before retail access began, as well as their price relationship through 2011. Note first that the gap that the high-cost states were trying to close is essentially maintained for the entire time period. Retail access states saw a price decrease between 1996 and 2002, which may be attributed to the automatic discounts and price caps that nearly all states had adopted as part of their "restructuring" legislation.

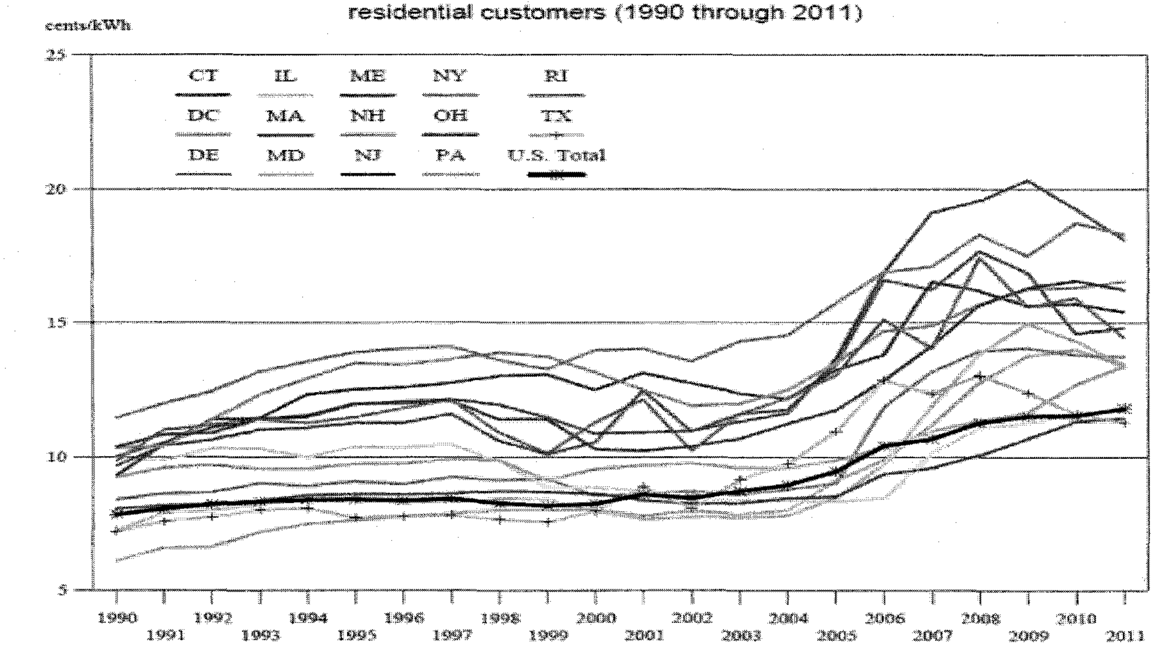
Figure 1. Weighted annual averages for all states, regulated states and states that ended price caps for residential customers (1990 through 2011)



Data source: DOE/EIA.

From 2002 to 2008 the weighted average price for these retail access states increased considerably, increasing by over 44 percent during that time period. Prices in regulated states in the same time period increased over 30 percent.

Figure 2. States with retail access and US average for residential customers (1990 through 2011)

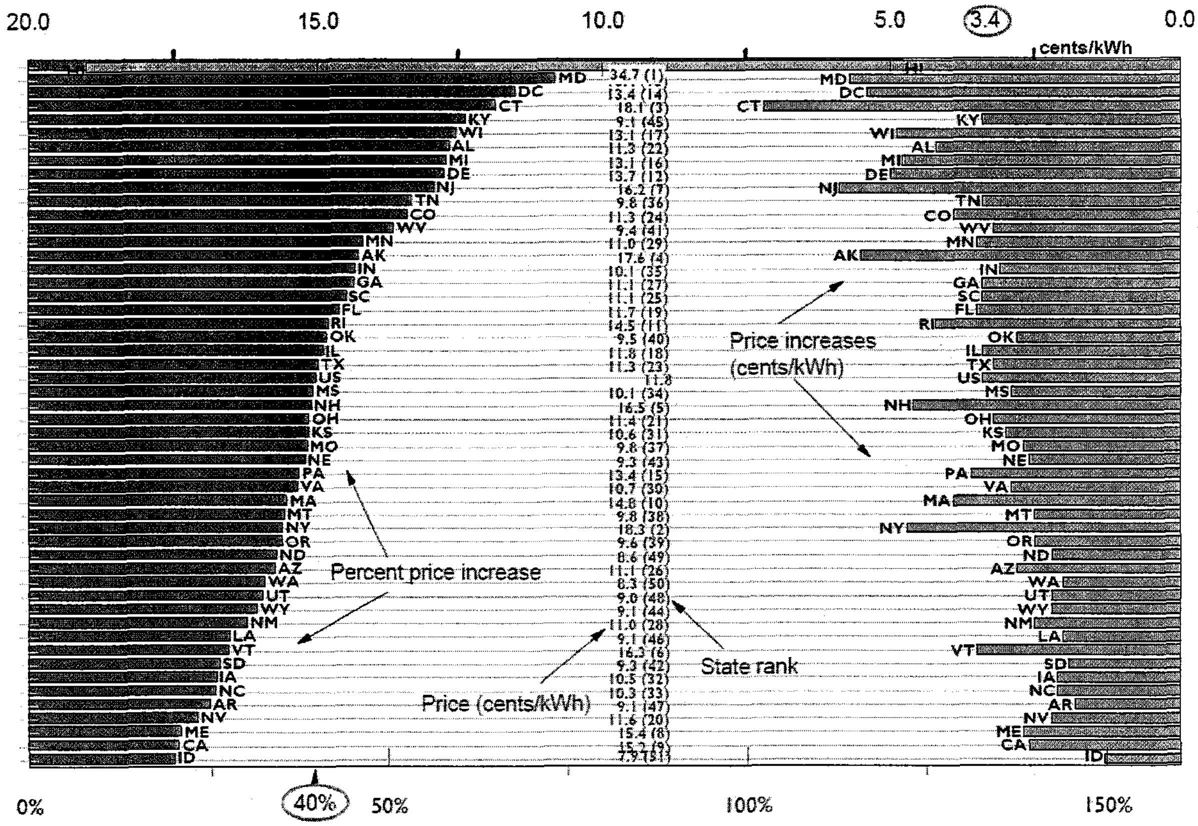


Data source: DOE/EIA.

Since 2008, prices in retail access states *decreased* somewhat, by 1.7 percent, while regulated states increased by nearly eight percent. Interestingly, the price gap between the weighted averages has not changed much over the years; the smallest difference between them was two cents per kWh in 2002 and the furthest apart was almost four cents in 2008. Last year the price gap was about three cents per kWh.

Figure 2 provides a closer look at retail access states, showing prices for all 14 retail access states and the US average. Note that there was quite a bit of variation over the years. The District of Columbia offered the lowest cost in 1990 and for several years thereafter, but now lies toward the middle of the range and above the national average. New York was the highest cost state for most years. Recently, Connecticut was the highest cost state for four years, but last year New York prices again moved slightly above Connecticut's. Of the 14 retail access states for the period 2008 to 2011, seven decreased in price (Connecticut, Delaware, Massachusetts, Maryland, Maine, Rhode Island, and Texas), six increased (D.C., Illinois, New Hampshire, New Jersey, Ohio, and Pennsylvania), and one did not change appreciably (New York). Two of the 14 were slightly below the national average in 2011 (Ohio and Texas), while the other twelve were above – with six states more than 25 percent above the national average (Connecticut, Massachusetts, Maine, New Hampshire, New

Figure 3. State percentage price increase (left side, bottom axis), price increase (right side, top axis), and 2011 prices (center numbers, with state rank), for residential customers, from 2002 to 2011



Data source: DOE/EIA.

Jersey, and New York).

The percent increase from 2002 to 2011 for all states is shown in **Figure 3** on page 5 (the left-side bars, using the bottom axis), in decreasing order. Every state saw an increase in electricity prices during this time period, but the range of increases varied considerably; Idaho increased by 20 percent, while Maryland saw a 74 percent increase.[4] The national average increase was 39.7 percent (40 percent is circled at the bottom of the chart).

Restructuring assumed that competition in generation would lower prices more than enough to offset any higher costs required to supply retail customers. That has not happened.

Twenty-three states, including eight of the 14 retail access states, increased at a higher rate than the national average.

The bars on the left in the chart are the price increases in cents per kWh (using the top axis); the national average increase was 3.4 cents per kWh (also circled). The numbers through the middle of the chart are the average electricity price for residential customers in the state. The state's rank appears in parentheses,(with the highest priced jurisdiction ranked as 1 and the lowest as 51.

Why Have We Not Seen an Apparent Residential Customer Benefit from Retail Access?

How should we account for the persistent price difference between the two state groups and the lack of a clear benefit to residential customers in retail access states? To answer this question, three important factors must be addressed. First, there is undoubtedly an impact on retail prices from fuel prices that can be seen in Figures 1 and 2, except that the average weighted price for the retail access states increased at a much faster pace.

Natural gas prices increased considerably from 2000 to 2008, with the average cost of natural gas for the industry increasing 110 percent during that period.[5] However, from 2008 to 2010 the average price of natural gas fell by 43.6 percent (based on the most recent available data) and has almost certainly fallen further since. Natural gas wellhead prices are currently at their lowest level since 2002.

[4] Hawaii had the highest percentage increase during this time period, a whopping 122 percent, which is shown with the overlapping bars on the left side of the chart. But since Hawaii is a special case with respect to electricity (and many things besides), the state is included in Figure 3 but is not included with other regulated states grouping shown in Figures 1 and 2. For similar reasons, Alaska is also not included in the regulated states group, but is included in Figure 3. Alaska and Hawaii are included in the US average shown in Figures 1 and 2.

[5] This is based on the weighted average cost of natural gas for the electric power industry, US Energy Information Administration, *Electric Power Annual*, 2010 Data Tables.

Coal price also saw a considerable increase, but unlike natural gas the average price of coal has continued to increase, rising 89 percent from 2000 to 2010. Natural gas in that same 2000 to 2010 period increased by 18 percent. Do fuel prices explain the price difference between the retail access and regulated states? Not entirely, primarily since there has not been a drop in retail electricity prices commensurate with the drop in natural gas prices. If natural gas prices and fuel prices in general are the reason for the electricity price run up, why then has there not been a sizable drop in electricity prices since 2008? Fuel prices may be part of the explanation, cannot explain the entire story.[6]

None of the factors we examined can adequately explain why prices in retail access states rose faster than those in regulated states.

A second factor that theoretically could explain retail access state price differences is the addition of new generation capacity that has been added since 2000. However, most states have been adding new generation, as well as new investments in transmission and distribution facilities. Nationally, electric generation capacity has increased by 28 percent from 2000 to 2010.[7] As between restructured retail access states and those that remain vertically integrated, it may be expected that regulated states have more incentive to add capacity (due to the Averch-Johnson effect). But, since prices in the restructured states increased faster than those in the regulated states during most of this period, this also fails to explain the difference.

Third, some may point to renewable energy investments, and in particular renewable portfolio standard (RPS) requirements that are intended to increase the proportion of renewable generation capacity in a state and may potentially increase costs and prices relative to conventional sources. The problem with this explanation is that some 29 states – including both retail access and regulated states – have adopted an RPS.[8] Also, while non-hydro renewable capacity has been expanding rapidly in recent years, it was still less than five percent of the total US generating capacity in 2011. Renewables and RPS adoption may become a bigger cost factor in the near future, but cannot explain the increase in prices that began in 2002. Similarly, the additional costs to comply with the recent and proposed EPA pollution

[6] Natural gas prices did not fully explain the electricity price increase from 2002 to 2008 either, so it is not surprising that electricity prices do not respond proportionately. For more on that point, see Kenneth Rose, "The Impact of Fuel Costs on Electric Power Prices," June 2007, prepared for the American Public Power Association (APPA). Posted at: http://www.appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf

[7] Based on total US net summer capacity, 2000 to 2010, from US Energy Information Administration, Form EIA-860, *Annual Generator Report.*

[8] North Carolina State University, Database of State Incentives for Renewables and Efficiency (DSIRE), http://www.dsireusa.org/

control rules will also likely lead to higher *future* prices.

All three of these factors – the fuel used for generation (and its cost), new capacity, and renewable capacity additions – will vary by state and region. To properly account and quantify the impact of each factor and isolate the impact of retail access from the others would require a much more sophisticated analysis than the one conducted here.

Any empirical analysis would also have to account for the timing of rate discounts that were imposed by law or regulation on each utility and when each state or utility ended the rate discounts or caps and began basing prices on a market mechanism. However, considering each factor on its own, it appears that none of them can fully explain why prices in retail access states increased at a faster pace than those in regulated states, or why there is no clear pattern of retail access *lowering* prices relative to regulated state prices. Another important factor or a collection of factors must also be exerting an impact.

Whatever temporary inducement is adopted to promote retail competition, alternative suppliers eventually must operate in the same wholesale market as the default supplier, and their costs must reflect current conditions.

The total wholesale power cost to supply retail customers plus the costs retail suppliers incur to serve retail customers could be another possible explanation – one that applies to all retail access states. The total wholesale cost of electricity includes the cost for energy, capacity, ancillary services, transmission service, and regional transmission organization administrative costs.[9]

Retail suppliers – load-serving entities, or LSEs – face costs and risks that are in addition to the cost of procuring power in the wholesale market. These include the risk that the load they serve will change due to weather or the economy, customer migration risk, risk of a regulatory or fuel price change, and risk that the wholesale market from which they secure power supply will increase, as may happen in the Texas market quite soon, beyond any level the LSEs had expected. In addition LSEs must bear administrative and legal costs to participate in a state's retail market. Finally, they must earn a profit on their operation. A vertically integrated utility faces many of these same risks, but others, such as customer migration risk, are applicable only in a retail access jurisdiction.

Finally, the real cost multiplier in a retail access, restructured setting is felt when all the wholesale and retail components of electricity service are added together. A vertically integrated utility – one that generates and distributes the power to end-use retail customers – provides all these services under its own roof, as it were. A competitive retail supplier must provide them with either its own generation or through arrangements with

[9] All retail access states are in an operating RTO or ISO, as are many (about half) of the regulated states.

others that have the energy, capacity, ancillary services, etc. necessary to serve the load-serving entity's retail customers.

The term used to describe this difference — one that may afford an advantage to vertically integrated utilities – is "economies of scope" (also known as vertical economies or synergies), this occurs when one firm can supply multiple products at a lower cost than could several separate firms making the same products independently. It was assumed when restructuring began that competition in generation (the energy component) would lower prices sufficiently to more than offset any higher costs that might be incurred to supply retail customers as a result of having multiple suppliers of these products in an amount sufficient to overcome the loss of vertical economies. The evidence so far suggests that has not yet happened. However, to assess why this may be so would necessitate taking a closer look at what has been happening in the wholesale markets run by the RTOs – which will be the subject of a subsequent article.

Given the limited success of restructuring and retail access to date, restructured states have tried a number of techniques to foster a more competitive retail market, including allowing municipal aggregation, letting customers in towns and cities group together in the hope of creating more buying power than an individual customer would face alone.

Another technique states have used to try to spark customer interest in shopping for electricity is to boost the price-to-compare of a "default supplier" – usually the former vertically-integrated utility – to create headroom for alternative suppliers to offer discounts from the default supplier's standard offer price.

In either case the reality of the wholesale market conditions will always prevail; eventually the municipal aggregator and other competitors must derive the power they propose to sell from the same wholesale market as the default supplier. Sooner or later, the non-generation costs required to serve customers must be reconciled with current power market conditions. There is no obvious way out of this circumstance as long as a broader regional wholesale structure exists. ■

Attachment 2:

"Revisiting 'the Genius of the Marketplace':
Cures for the Western Electricity and Natural Gas Crises"
By Ralph Cavanagh

Revisiting "the Genius of the Marketplace": Cures for the Western Electricity and Natural Gas Crises

California's restructuring stripped utilities of responsibility for retail customers' electricity resource portfolios, leaving most of the state exposed to intense spot market volatility. Subsequent experience reinforces the need for all states to redefine a regulated portfolio management function.

Ralph Cavanagh

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The author is grateful for thoughtful comments by Sheryl Carter, Rachel Gold, David Goldstein, David Hawkins, Eric Heitz, Kit Kennedy, and Peter Miller.

On one point at least, observers of the West's energy disorders agree: some very basic portfolio management skills have been conspicuously lacking. In particular, critics ask repeatedly, how could a major state have come to rely on a day-ahead spot market to procure most of its electricity supply? The answers are instructive and point toward enduring solutions. For most customers, there is a crucial portfolio management function associated with electricity resources, which has many features of a classic natural monopoly. Regulators cannot leave this function exclusively to unregulated participants in wholesale markets. Without designated portfolio managers operating under incentives to promote long-term public interests, deregulation of wholesale electric markets is unlikely to succeed.

I. The Crisis Begins

California launched its spot market in electricity commodities on March 31, 1998. After more than two years of reassuringly low

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prices and seemingly robust competition, calamity struck:

• Wholesale electricity prices that previously had ranged between 2 and 3 cents per kWh soared to at least 15 cents, on average, from June through August 2000. That average price then doubled again in December 2000 and January 2001, even though demand levels were far below their summer peaks, and at one point the price reached $1.50 per kWh.[1]

• Natural gas prices, typically at $2 to $3 per million BTUs, climbed in January 2001 to nearly $10 per million BTUs nationally, with prices spiking above $50 in Southern California. As of April 2001, natural gas options contracts on the New York Mercantile Exchange were selling at levels above $5 for every month through March of the following year.[2]

Based on the gap between runaway wholesale electricity costs and state-frozen retail electricity rates, the West's two biggest electricity distribution companies—PG&E and Southern California Edison—claimed losses in excess of $12 billion from May 2000 to January 2001 on unreimbursed wholesale electricity purchases. Consumer advocates countered that these losses had been offset in part by gains on power sales from generators still owned or controlled by the utilities. By any measure, however, the distribution companies were on the brink of insolvency by early 2001.

At the same time, notices of supply emergencies became routine throughout the state, as operating reserves dropped below 5 percent for weeks on end. A host of public officials have been wondering loudly how matters could have reached such a pass.

Some have blamed alleged runaway growth in California's electricity consumption, along with environmental regulations that supposedly blocked power plant construction and operation. I respond briefly below to these largely discredited contentions, but my emphasis in what follows is the neglected portfolio management functions that could have averted the crisis and are now essential to overcoming it.

Neglected portfolio management functions could have averted the crisis and are now essential to overcoming it.

II. California's Electricity Use and Environmental Regulations

Reports of a dramatic surge in California electricity use are simply inaccurate. The estimated statewide annual increase for 2000 was about 4 percent, and the annual rate of growth from 1990 to 1998 was under 1 percent.[3] California accounted for only about 15 percent of the increase in Western peak power use from 1995 to 1999, although the state represents about 40 percent of the total system.[4] In other words, electricity consumption for the other 10 western states has been growing more than twice as fast as California's, on average. In the nation as a whole, electricity use was up 22 percent from 1990 to 1999, about double California's figure for the same period.[5]

Some contend that environmental constraints on electric generation somehow caused rising electricity costs in California. But as *The Los Angeles Times* noted on Jan. 25, 2001: "California regulations have not short-circuited the amounts of electricity produced, according to power company representatives." The only exception that the *Times* could find was one small and obsolete plant accounting for less than one-fifth of 1 percent of the state's demand, which had chosen "not to participate in a smog market that gives companies more flexibility in meeting pollution limits."[6] Ample opportunities remain to reduce pollution at relatively low costs by cleaning up this and other older fossil generators, which could both increase their production and cut their emissions after modifications.[7]

Most complaints about the state's siting rules are just as unfounded. The California Energy Commission (CEC) works aggressively to site new power plants, generally in a year or less, and the agency can override local opposition where broader public interests

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dictate. For much of the 1990s, investors throughout California and the West generally had no interest in financing new power plants because of low prices and widespread electricity surpluses, not because of environmental rules. Even so, the CEC licensed 11 power plants in the early 1990s, and eight are producing almost 1,000 MW of power today (the equivalent of about 1 million California households).[8] From 1991 to 1995, environmental groups strongly supported efforts by the CEC and other state agencies to add another 1,400 MW of renewable energy and highly efficient gas-fired plants, but a shortsighted Federal Energy Regulatory Commission blocked the power purchase contracts that were prerequisites to construction.[9] In the two years following April 1999, almost 10,500 MW of new large-scale plants (equivalent to one-sixth of California's peak needs) have received CEC siting approval, and more than 5,000 MW are poised to follow.[10]

III. What Really Happened

No single factor explains recent and closely linked price increases in two essential energy commodities. The upswing in natural gas prices most prominently reflects a prolonged contraction in exploration and storage due to low commodity prices, coupled (in the Southwest) with reduced pipeline capacity as a result of a summer 2000 explosion. And much costlier natural gas has in turn helped to drive up the operating cost of electric generation. High electricity prices also reflect reduced Northwest hydropower production due to low rainfall and the generally overstressed state of the western power grid, which has suffered from a decade of reduced investment in energy efficiency, generating capacity, and transmission upgrades.[11] As if all that were not enough, investigations continue of alleged anti-competitive practices by many market participants.[12]

The Commission insisted utilities would have to procure all power from the short-term wholesale spot market.

But none of these factors, even in self-reinforcing combination, could have instigated a statewide financial crisis in 2000–2001 if most of California's electricity load had not been consigned to the spot market. This, in turn, reflected a fundamentally flawed, if well-intentioned, policy judgment some five years earlier.

IV. Portfolio Management Lost

Between April 1994 and January 1996, the California Public Utility Commission (PUC) devised a plan for restructuring the electric utilities subject to its jurisdiction. A prominent feature was eliminating utilities' longstanding responsibility for electricity resource investments.

The Commission acknowledged that, even after opening retail electricity markets to competition, many if not most customers would continue to procure their power from their hometown distribution companies. But the Commission insisted that these utilities would have to procure all the power that they sold directly from the short-term wholesale spot market. For those concerned about potential volatility in the spot market, the Commission had a ready response:

> Many customers may be disinterested in the choice of generation but desire price stability and predictability over a defined period of time. Such customers are free to elect hedging contracts which may be concluded with any individual or entity willing to take the counter-part risk. . . .
>
> In our view parties [who] agree to accept the risk in a hedging contract may have generation facilities or contracted rights to generation but we see no need to restrict their qualification or in any manner make hedging contracts, termed "contracts for differences" in much of the literature, the object of Commission concern. *Both entry into and exit from such a business, as well as the terms of such contracts, are left to the genius of the marketplace and the will of market participants.*[13] [emphasis added]

Would this suffice for the average customer with little sophistication or understanding of electricity commodity markets? The Commission thought so:

> At least initially, most observers anticipate that a significant

> majority of residential and small load commercial and agricultural users will either prefer, or lack competitive alternatives to, reliance upon the local utility to procure electric energy as well as provide distribution and related services. These average ratepayers may be referred to as "full service customers." During the transition period, we have concluded that our greatest contribution to those who initially elect or find no alternative to the status of full service customers is to ensure that they gain access to the competitive price for generation in a manner that is free of cost and confusion . . . A customer who, for any reason, desires a price structure which differs from the day by day, hour by hour, revelation in the Exchange will be afforded the opportunity to purchase a financial hedge . . . from any counterpart party who may or may not own or have contractual rights to any specific generation.[14]

In sum, utilities would cease their portfolio management functions and become mere passive conveyors of "day by day, hour by hour" spot market prices, which customers could either accept or hedge by seeking portfolio management services in the open market. In reaching these conclusions, the Commission disregarded strenuous objections from the Natural Resources Defense Council and others.[15] And although the California legislature later made numerous changes in the PUC's proposal, the Commission's experiment with market-driven portfolio management went forward. Its catastrophic failure forced the legislature to take emergency action in January 2001 by directing an agency of the State of California to assume responsibility for power acquisition and begin assembling long-term contracts from multiple suppliers.[16] Unfortunately, of course, it would be difficult to have picked a less opportune time to begin hedging commodity risks in electricity markets. A broader vision of the portfolio function will be required to restore affordable and reliable electricity service.

Utilities would become mere passive conveyors of "day by day, hour by hour" spot market prices.

V. Portfolio Management Regained

California has now thoroughly tested the proposition that multiple competitive decision makers can orchestrate a diversified and affordable mix of resources for meeting a healthy economy's electrical services needs. The verdict is in with a vengeance. Yet the state was not alone in this dangerous venture; although other jurisdictions were less explicit in their choices, sharply reduced investment in all aspects of electricity infrastructure—from end-use efficiency to transmission—was the order of the day throughout much of the 1990s.[17]

Before the California PUC intervened so catastrophically in the mid-1990s, the state's electricity distribution companies and 3,000-odd counterparts across North America had been responsible for choosing the mix of generating resources, purchased power, and demand-side efficiency improvements that would minimize the costs and price volatility of reliable energy services.[18] Both Congress and state legislatures had addressed these portfolio obligations extensively; California law provided as follows:

> (a) the Legislature finds and declares that, in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and encourage the diversity of energy sources through improvements in energy efficiency and development of renewable energy resources, such as wind, solar, biomass, and geothermal energy.
>
> (b) the Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and which are not being exploited by any other entity.[19]

California now needs to restore these principles to their earlier prominence, with special emphasis

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on a theme borrowed from earlier Northwest legislation: Energy efficiency investments are compelling candidates for inclusion in any successful electricity-resource portfolio.[20] While there was much dissatisfaction with utilities' performance historically as portfolio managers, all now have special cause to appreciate the social importance of the diversification and aggregation functions at issue. Portfolio management looks increasingly like a classic "natural monopoly" that offers significant potential benefits to customers and society generally. That does not mean, of course, that it is physically impossible to have multiple entities making decisions about acquiring resources for an electricity distribution system, any more than it is physically impossible to run multiple power distribution lines into a building. But in either case, abandoning central direction means higher costs for customers and society.[21] Distribution companies typically have discharged the portfolio responsibility, although certainly they are not the sole candidates, and nothing in the fundamentals of the function itself requires ownership of the resources that contribute to the portfolio.[22] Here as in other contexts, appropriate regulatory oversight is needed to ensure that the monopoly works in the public interest.

This does not mean that all customers in a service territory must be assigned initially to the same manager, or that competitive alternatives must be suppressed, or that management franchises should be permanent. Individual customers should be allowed to opt out of regulated portfolio management, as long as any right of return is conditioned to protect the regulated service and its other customers from financial harm. What California shows, paradoxically, is that those who want to offer competitive portfolio services have a particular stake in ensuring that good regulated service is available to all; the competitive providers were among those swamped in the tidal wave of price volatility from a largely unhedged spot market.

As regulators begin considering how best to reestablish portfolio management functions in California and elsewhere, several considerations should be paramount.

1. Energy efficiency and renewable energy represent the fastest, cheapest, and cleanest ways to lighten the load on overtaxed electricity grids. Thanks in part to legislation signed by Governor Davis last September, California has many immediate opportunities to accelerate its energy-efficiency and renewable-energy investments, which already have contributed more than 15,000 MW to a western power grid that never needed them more.[23] For example, in January 2001, the California Energy Commission issued emergency upgrades for efficiency standards governing all new buildings and equipment, which should save about 1,000 MW over the next five years.[24] The legislature also has created a new 10-year investment fund for sustainable energy technologies that exceeds $5.5 billion.[25]

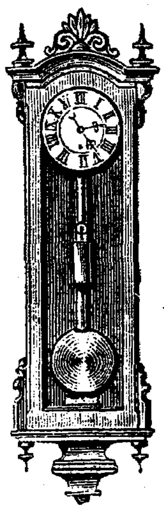
In 2001, the state moved to do still more of what it already does best. In April, Governor Davis signed two bipartisan bills (SB5X and AB29X) that provided more than $700 million in supplementary funding from the state's budget surplus for energy efficiency, renewable energy, and low-income energy services. Environmental groups will also support additions of highly efficient natural gas generation. But for those angered by rising fuel prices, the best revenge is still needing and using less. Congress could help immediately by enacting S.207, a bipartisan bill that provides new financial incentives to improve significantly the energy-efficiency of new buildings and equipment. These incentives would also prod other western states to revive flagging energy-efficiency momentum. All of these initiatives are designed to reduce costly near-term public investments in additional fossil generation to meet urgent reliability needs. Westerners outside California should be

For those angered by rising fuel prices, the best revenge is still needing and using less.

asking hard questions about what, if any, comparable efforts their utilities, regulators, and legislators are making.

Whether or not energy distribution companies retain portfolio management responsibilities, regulators must act to eliminate conflicts of interest that arise whenever distribution revenues are tied to throughput over the wires. No conceivable public interest is served by rewarding distribution system managers for diminished progress in energy efficiency, or for increased use of a commodity that others are now responsible for producing. The solution is to introduce modest annual adjustments in regulated electricity rates that automatically correct for unexpected fluctuations in electricity use. In other words, if traffic over the wires exceeds or falls short of estimates made at the time that regulators last established rates for electric distribution service, rates for the next year should be adjusted to compensate. The recovery of distribution costs is then independent of the total volume of electricity passing over the wires, although customers continue to be charged on the basis of kilowatt-hour consumption.[26]

This is the model that the Public Utility Commission of Oregon and Pacificorp embraced in 1998, at the request of a diverse coalition of parties.[27] Portland General Electric agreed in September 2000 to file "ratemaking alternatives for distribution services under which the revenues and net income of PGE are not tied to or derived from kilowatt hour sales."[28] The San Diego Gas & Electric Company became a convert to this approach in January 2001, citing "the need for a strong and renewed focus on energy efficiency" in its decision to file for rate reforms to ensure that "SDG&E's earnings would not be proportional to the amount of energy that consumers use."[29] And by large bipartisan majorities, legislators subsequently wrote this policy into California law.[30]



2. Affordable power can be green power. Across California, developers of new generation are racing to site and build plants (both renewable and fossil-fueled) that are dramatically cleaner than the incumbents. By the end of 2001, the state expects to add 2,353 MW of combined cycle gas generation and 800 MW of renewable generation.[31] The 15,000-odd MW of gas and renewable capacity additions anticipated by 2003 are both clean and large enough to begin improving California's air quality by displacing dirtier competitors during at least some hours of the year. A particularly striking near-term benefit is minimizing the operation of emergency diesel generators, whose emissions per kWh of nitrogen oxide and particulate matter exceed those of new gas-fired plants 50- to 100-fold.[32] In 1998, the California Air Resources Board listed diesel exhaust as a toxic air contaminant, and later concluded that it is responsible for more than 70 percent of the statewide cancer risk from air pollution.[33]

3. Low-income customers need immediate relief. Given the West's wholesale electricity prices, not even the most adept portfolio manager could rule out near-term increases in residential rates, and retail gas prices surged throughout the nation during the winter of 2000–2001. California and neighboring states traditionally have tried to ensure that low-income households receive targeted energy efficiency assistance and rate discounts; in California, these programs are administered by the state's utilities and funded through a modest surcharge on bills. Additional resources must be added now, to ensure that no one loses access to essential services. In April 2001, the California legislature approved emergency legislation (SB5X) that provides $240 million of supplementary funding. The federal government could help by expanding the Low-Income Home Energy Assistance Program (LIHEAP) and complementary energy efficiency investments.[34]

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VI. Conclusion

No one wants to resume California's experiment with entrusting retail customers' electricity portfolios solely to "the genius of the marketplace." But other states unwittingly are doing precisely that, by allowing energy distribution companies to defer most investment in new resources, and in particular to neglect the diversification opportunities associated with energy efficiency and renewable resources. Adroit portfolio management, and incentives to achieve it, must become paramount objectives of both state utility regulators and those entrusted with this vital public function. ■

Endnotes:

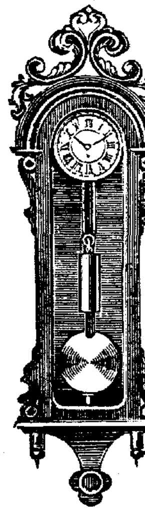
1. See Rebecca Smith, *Probe of California Power Prices Begins, But New Plants Aren't Seen as Solutions,* WALL ST. J., Sept. 11, 2000 ("[t]he average cost of power, per megawatt hour was $185 in August, $117 in July and $167 in June"). A price of $1.50 per kWh cleared the California Power Exchange (PX) day-ahead market for deliveries at 6 AM on Dec. 13, 2000, according to the PX Web site (http://www.calpx.com). The weighted average cost of system power purchased through the PX from Nov. 20 through Dec. 20, 2000, was 28 cents per kWh; for the period Dec. 20 through Jan. 22, 2001, it rose to 29.4 cents per kWh. These weighted averages are reported by Green Mountain Energy, in the form of retail electricity bills received by the author for those months.

2. This reflects the Henry Hub natural gas options contract prices listed on http://www.nymex.com through March 2002, as of April 5, 2001.

3. These data appear at http://www.energy.ca.gov/electricity/consumption-by-sector.html (May 30, 2001).

4. See Northwest Power Planning Council, *Study of Western Power Market Prices: Summer 2000*, Oct. 11, 2000, at 15. The report notes that "by far, the most rapid growth" occurred in Arizona, New Mexico, and southern Nevada: "[a]lthough this area only accounted for 12 percent of WSCC summer peak loads in 1995, it accounted for 47 percent of their growth from 1995 to 1999." *Id.* at 14.

5. See U.S. Department of Energy, MONTHLY ENERGY REV., Dec. 2000, at 99 (data reflect electricity end use); California consumption grew by 11 percent from 1990 to 1999, according to the California Energy Commission (*supra* note 3).



6. Marla Cone and Gary Polakovic, *Bush's Idea of Easing Smog Rules Won't Help, Experts Say,* L.A. TIMES, Jan. 25, 2001.

7. See Paul Joskow and Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market during Summer 2000,* filed with FERC on Nov. 21, 2000, at 9–13 (reviewing abundant opportunities for NO_x reductions at California generators, and noting that the five most polluting gas turbines in the Los Angeles air basin could cut emission rates by 65 percent "for costs of less than $1 million per unit").

8. See California Energy Commission, http://www.energy.ca.gov/sitingcases/backgrounder.html (May 30, 2001).

9. The FERC decision expressed "grave concern about the need for this capacity" and concluded that California utilities could not lawfully be required to execute the purchase contracts. Federal Energy Regulatory Commission, Order on Petitions for Enforcement Action Pursuant to Section 210(h) of PURPA, Docket No. EL95-16-00 (Feb. 23, 1995), at 26–27.

10. For a continuously updated report on the status of siting proceedings at the California Energy Commission, see http://www.energy.ca.gov/sitingcases/backgrounder.html (May 30, 2001).

11. In the region drained by the Columbia River and its tributaries, precipitation for the four months beginning November 2000 was 49 percent, 57 percent, 40 percent, and 53 percent of average, respectively; February 2001 streamflows at the Dalles on the Columbia River were 49 percent of the 60-year average; federal hydropower generation for February 2001 was at least 4,000 MW below 1995–2000 averages; and the National Weather Service predicted that the year ending in July 2001 would bring "the second lowest volume runoff on record" at the Dalles (trailing only 1977). Bonneville Power Administration, *Power System Data for the Week Ending March 2, 2001.* The issue of reduced resource investment is addressed below in note 17.

12. For a provocative treatment, see Robert McCullough, *Price Spike Tsunami: How Market Power Soaked California,* PUB. UTIL. FORTNIGHTLY, Jan. 1, 2001. The California Independent System Operator renewed formal claims of anticompetitive actions by generators on March 1, 2001. See also Tina Davis, *Cal-ISO to FERC: Power Sales Reek of Market Power,* Mar. 2, 2001, ENERGY DAILY, at 1 (ISO contends that "as much as $247 million or 21 percent of the real-time energy costs during December 2000 and $315 million or 63 percent of the real-time energy costs for January 2001 represent charges that may exceed just and reasonable levels").

13. California Public Utility Commission Decision 95-12-063 (Dec. 20, 1995) as modified by Decision 96-01-009 (Jan. 10, 1996), at 8.

14. *Id.*, at 56–57.

15. A full review of the portfolio management issues appears in the National Resources Defense Council (NRDC) initial response to the Commission's proposal, and in a report issued shortly before the Commission's proposal was published. See Opening Comments of the Natural Resources Defense Council and Comments on Balancing Public Policy Objectives in a Competitive Environment, June 7, 1994, at 2–3 and 7–10; Ralph Cavanagh, *The Great Retail Wheeling Illusion* (NRDC, March 1994), at 3–8. For an analogous and equally timely critique of the PUC's proposal, see V. John White, *On a Cruel Sea*, Coalition Energy News (Sacramento, CA: Center for Energy Efficiency and Renewable Technologies, Spring 1994), at 2.

16. See AB1X (Keeley), available in full at http://www.assembly.ca.gov/acs/acsframeset2text.htm (May 30, 2001).

17. See Northwest Power Planning Council, *Study of Western Power Market Prices: Summer 2000* (Oct. 11, 2000), at 13–14 (concluding that, while western peak loads increased by 12,000 MW from 1995 to 1999, generating capacity increased by only 4,600 MW and energy efficiency investment dropped substantially throughout the utility sector).

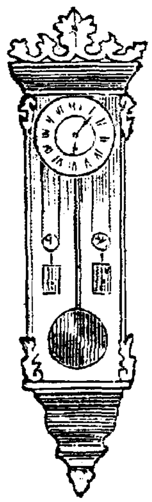
18. The California PUC had plenty of encouragement, much of it—ironically and tragically—from politically potent industrial interests who have been particularly hard hit by recent increases in electricity rates.

19. California Public Utilities Code §701.1. As NRDC noted at the time (*supra* note 15 at 3), the initial PUC proposal conspicuously omitted any reference to this statute. The first legislation to address portfolio functions in detail was the Pacific Northwest Electric Power Planning and Conservation Act of 1980, 16 U.S.C. §839 *et seq.*

20. See 16 U.S.C. §839b and 839d.

21. In a prophetic 1991 analysis, the Northwest Power Planning Council demonstrated as much when it quantified literally billions of dollars of potential benefits from centralized resource procurement, compared with disaggregated development across a regional utility system. See Northwest Power Planning Council, *1991 Northwest Conservation and Electric Power Plan*, Vol. II, Part II, at 793–95 (1991).

22. In 1999, Montana opened the way for a portfolio-services competition; the statute established the possibility that a new statewide cooperative or some alternative provider might replace the incumbent distribution company as the entity responsible for executing procurement contracts on behalf of customers who did not choose a different supplier. See Montana Code Annotated, Title 35, Ch. 19, §101; and Title 69, Ch. 8, §416 and §417.



23. See California Energy Commission, *The Energy Efficiency Public Goods Charge Report*, Dec. 1999, at 12 (savings estimates cover 1975–1998).

24. See http://www.energy.ca.gov/releases/2001_releases/2001-01-03_new_standards.html (May 30, 2001).

25. This legislation, enacted as SB1194 and AB995, is codified at §399 of the California Public Utilities Code.

26. For thoughtful treatment of these and related issues, see the Web site of the Regulatory Assistance Project at http://www.rapmaine.org.

27. Public Utility Commission of Oregon, Order No. 98-191 (May 5, 1998; approving "alternative form of regulation" based on proposal by PacifiCorp, the Oregon Department of Energy, the Citizens Utility Board, the Natural Resources Defense Council, and the Northwest Energy Coalition).

28. This commitment appears in a stipulation that the Oregon Public Utilities Commission acknowledged as "in the public interest" in its order approving Sierra Pacific's acquisition of Portland General Electric. Order No. 00-702 (Oct. 30, 2000), Appendix C, at 4. PGE also agreed not to propose fixed charges "as a means of achieving the separation from kilowatt-hour sales," ensuring that customers' incentives to improve efficiency would not be reduced as a consequence of the pricing reforms. *Id.*

29. Letter from Pamela J. Fair, Vice President, Consumer Services, SDG&E, to Ralph Cavanagh, Natural Resources Defense Council, Jan. 31, 2001.

30. See Public Utilities Code section 739.10, which directs the Public Utilities Commission to ensure that "errors in estimates of demand elasticity or sales do not result in material over- or under-collections" of utility revenues.

31. The gas-fired generation additions are described in California Energy Commission, *supra* note 8, the renewable additions were reported to me in a March 5, 2001, communication from Marwan Masri, Manager of Renewable Energy Programs for the California Energy Commission, and reflect the cumulative impact of renewable energy investments orchestrated by the Commission since 1998.

32. California Air Resources Board, *Air Pollution Emissions from Electricity Generation*, Sept. 2000. Typical diesel engines emit 25–30 pounds of NO_x and 1–3 pounds of particulate matter (PM) per mWh, compared with 0.05 pounds of NO_x and 0.03–0.07 pounds of PM for a new combined cycle gas-fired plant in California.

33. See California Air Resources Board, *Identification of Diesel Exhaust as a Toxic Air Contaminant*, Aug. 1998; *Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles*, July 13, 2000, at 15.

34. For specific recommendations by the broad-based Campaign to Keep America Warm, see http://www.save-liheap.org.

Attachment 3:
"Reinventing Competitive Procurement of Electricity Resources"
By Ralph Cavanagh

Reinventing Competitive Procurement of Electricity Resources

by Ralph Cavanagh

With an announced intention of investing up to $2 trillion over the next two decades and abundant experience in resource procurement and integration, U.S. utilities could lead a clean energy transition.

A worldwide search is on for affordable low-carbon energy solutions, but looks mostly in the wrong places. We need savvy and credit-worthy institutions capable of choosing among a bewildering array of resource options, building diverse portfolios tailored to local conditions, and integrating elements with widely differing output characteristics, using grids big and responsive enough to accommodate variable demand and generation inexpensively. Wherever feasible, those institutions should be displacing other energy resources with efficiency improvements that offer equivalent or better services at lower cost. Recent candidates for this demanding role include national and local governments, venture capitalists, investment bankers, software engineers and information technologists.

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All can contribute, but none come close to replacing properly motivated and financially robust electric utilities. With an announced intention of investing up to $2 trillion over the next two decades and abundant experience in resource procurement and integration, U.S. utilities have no real competitors in leading a clean energy transition. But every state's regulators face significant unfinished business in ensuring that utilities that do this well are financially healthier than those that abdicate their responsibilities. Too often, such abdication remains both the path of least resistance and lowest financial risk to utilities, despite dismal consequences for customers and environmental quality. To compound the problem, an interminable state-by-state effort to restructure the electric industry reveals no emerging consensus.

This article recommends a way forward that both accommodates diversity in electric utility structure and avoids using national governments to dictate investment decisions. Its overarching theme is reliance on competitive resource procurement by effectively motivated utilities.

I. Why Worry?

Widespread paralysis on domestic energy and climate policy in 2010 may in part reflect a reduced sense of urgency. After years of tight supplies, strained distribution systems and soaring prices, U.S. energy consumption suddenly dropped 7 percent between 2007 and 2009. Compared with 2005, the nation's greenhouse gas emissions were down 10 percent in 2009. In 2008 and 2009, electricity use declined in consecutive years for the first time in memory.[1] Domestic oil use peaked in 2005, and by 2009 annual oil consumption was down by 10 percent. The trend of fossil fuel prices since mid-2008 is generally downward, and reports abound that plentiful natural gas supplies will persist for decades, thanks largely to advances in drilling technology. Worldwide, despite the continued economic surges of giants like China, Brazil and India, total energy use dropped by 1.2 percent in 2008 and another 2.2 percent in 2009.[2] Can't we all just relax for a while? This assumes, of course, that we can instantly forget months of continuously updated images from the most destructive oil spill in U.S. history.

But the latest projections from the U.S. Energy Information Administration nicely frame the case against complacency.[3] EIA sees global energy consumption growing by almost 50 percent over the next quarter century if business as usual is allowed to reassert itself. Greenhouse gas emissions and fossil fuel use would increase at comparable rates. That would make today's dangerous oil dependence much worse and all but eliminate any chance to suspend a uniquely dangerous global experiment with climate disruption. For the U.S., short-term declines in greenhouse gas emissions were driven primarily by an unprecedented 10 percent drop in coal use for electric generation from 2007 to 2009, reflecting sudden shifts in fossil fuel prices and economic conditions that are hardly likely to persist.

II. The Energy Efficiency Imperative

Electricity and natural gas distributed by regulated utilities account for more than half of the global warming pollution associated

[1] U.S. EIA data begin in 1949, although annual totals are reported starting only in 1970. *See* www.eia.doe.gov/aer/pdf/pages/sec8_5.pdf.

[2] *See* U.S. Energy Info. Admin., *International Energy Outlook 2010 – Highlights* (May 25, 2010) (www.eia.doe.gov/oiaf/ieo/highlights.html).

[3] U.S. Energy Info. Admin., *International Energy Outlook 2010* (www.eia.doe.gov/oiaf/ieo/index.html).

with U.S. fossil fuel consumption. Electricity generation alone accounts for approximately 40 percent of U.S. emissions, and its rate of growth from 1990-2005 was more than double that for the rest of the economy. Utilities also are by far the nation's largest investors in energy technology and infrastructure; electric utilities alone plan to commit $1.5 to $2 trillion over the next two decades, exceeding analogous federal expenditures by an order of magnitude.[4] Where those dollars go will help determine long-term U.S. economic and environmental performance.

Decades of evidence now argue for increased allocations to electricity resources with low costs, no fuel needs and no harmful emissions. In a comprehensive assessment of cost-effective domestic energy efficiency opportunities, McKinsey & Company identified potential ten-year savings of $1.2 trillion in U.S. utility bills.[5] MacArthur laureate David Goldstein believes that aggressive efficiency improvements can drive domestic energy consumption down by more than 80 percent within four decades, and that ten trillion dollars in associated savings is a gross underestimate.[6] These projections are buttressed by recent remarkable findings from more than 30 years of utility-sector experience with energy efficiency initiatives:

- From 1980-2008, the Pacific Northwest achieved electricity savings equivalent to five giant coal-fired power plants (almost 4,000 average MW) at an average cost of two cents per kWh, resulting in a cumulative net annual reduction in electricity bills of $2.3 billion/year and in CO_2 emissions of almost 15 million tons/year;[7]
- California's investor-owned utilities recently reported the results of their 2009 efficiency programs, which show a 10 percent increase in annual savings from a record-breaking 2006-2008 program cycle, providing an estimated reduction in CO_2 emissions of more than 1.5 million tons for that year alone. These gains were driven by investments of about $630 million, or 2.5 percent of the utilities' electric revenues, as energy efficiency continued to be the cheapest resource available, costing less than half as much (4 cents) per kWh as supply-side alternatives);[8]

4 The Brattle Group, *Transforming America's Power Industry: The Investment Challenge 2010-2030* (The Edison Found., Nov. 2008) at 2.

5 McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy* (2009) http://www.mckinsey.com/clientservice/electricpowernaturalgas/us_energy_efficiency/ The assessment includes lighting retrofits, improved heating, ventilation, air conditioning systems, building envelopes, and building control systems; and higher performance for consumer and office electronics and appliances.

6 *See* David Goldstein, *Invisible Energy: Strategies to Rescue the Economy and Save the Planet* (Bay Tree Pub. 2010) at 5 & 128-29.

7 *See* Northwest Power and Conservation Council, *Energy Efficiency: 30 Years of Smart Energy Choices* (Council Doc. 2010-3, 2010) at 2.

8 Energy savings, investment and cost-effectiveness data are from the Annual Reports on Energy Efficiency Programs for 2006 through 2009 submitted by Pacific Gas and Electric Co., Southern California Edison, and San Diego Gas and Electric Co. to the California Public Utilities Commission (available at http://eega2006.cpuc.ca.gov/Default.aspx). CO_2 emissions are estimated based on the avoided

- The Lawrence Berkeley National Laboratory concluded in July 2009 that utility investment in energy efficiency nationwide rose by 20 percent in 2008. LBL identified a potential for a further quadrupling by 2020.[9] More recent data from the Consortium for Energy Efficiency indicate that the utility industry accelerated its energy efficiency investment in 2009 by more than one-third, with electric utility expenditures reaching $4.4 billion. Even discounting one-time "stimulus bill" infusions, utility energy efficiency expenditures doubled between 2006 and 2009.[10] Preliminary data suggest continued growth in 2010, yielding an energy efficiency budget for the year of $5.4 billion for the U.S. electricity sector alone. That is still well under two percent of the nation's $350 billion electricity bill, yet the trend is certainly encouraging.[11]

But utility investment in other resources and infrastructure has of late been declining across the United States, despite some highly visible efforts to upgrade grids and add renewable energy capacity. From 2008 to 2009, utilities' capital investment dropped by 11 percent ($10 billion).[12] Any extension of this trend would be terrible news for those who seek decarbonization of the electricity sector, since market realities long ago exploded any prospect of significant generation additions or grid enhancements without long-term financial commitments from utilities.[13]

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emission rate for electric savings of 4.37×10^{-7} million metric tons of CO_2 equivalent per MWh from the California Air Resources Board, *Climate Change Scoping Plan Appendices*, Vol 2: Analysis and Documentation, Dec. 2008, p. I-23, www.arb.ca.gov/cc/scopingplan/document/appendices_volume2.pdf. Electric efficiency program investments for 2009 are estimated from total electric and natural gas efficiency investments, based on the relative investment in electric efficiency to total efficiency investments in 2006 - 2008 on average. Utility electric revenues are from the U.S. Department of Energy, Energy Information Administration, Form EIA-826, Monthly Electric Utility Sales and Revenue Data (2010). The California Energy Commission estimates that electricity from a conventional combined cycle generator cost more than 10 cents/kWh in 2009. California Energy Commission, *Comparative Costs of California Central Station Electricity Generation*, CEC-200-2009-07SF, January 2010, at 3, www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

9 G. Barbose, C. Goldman & J. Schlegel, *The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S.* (LBNL-2258E, July 2009).

10 Consortium for Energy Efficiency, *Blazing the Trail: 2009* (CEE Annual Report and Efficiency Program Report, 20-21). Doubling of budgets refers to combined outlays of U.S. electric and gas utilities, which grew from $2.6 billion in 2006 to $5.3 billion in 2009.

11 Data are from a briefing to EEI's Institute for Electric Efficiency Advisory Group by Marc Hoffman, Executive Director, Consortium for Energy Efficiency (Sept. 9, 2010).

12 *Frugal Utilities Rise to Top in Annual Financial Ranking*, Pub. Util. Fort., Sept. 2, 2010 (reporting that industry-wide capital expenditures "totaled $83.9 billion in 2009, versus the previous year's expenditure of $93.8 billion").

13 This does not mean, of course, that utilities need to own the new generation and infrastructure. *See, e.g.*, Am. Wind Energy Ass'n, Wind Energy Weekly, Sept. 10, 2010 (describing a new 260 MW wind project in Goldendale, WA whose financing centers on a commitment by a consortium of southern California utilities to pay for a 20-year block of power representing over 70 percent of the project's expected annual production, with the balance of power to be

III. The Challenge of Chaotic Industry Restructuring

What once looked like an irresistible industry-wide restructuring model for electric utilities has stalled.[14] Enthusiasm for "deregulation" plummeted after the failure of western wholesale markets during 2000-2001, and subsequent episodes of extreme price volatility and highly publicized market manipulation. Some states remain committed to retail competition among electricity providers, maintaining that consumers will benefit by the ability to choose among multiple suppliers. Others seek a system that integrates traditional state-regulated retail electricity service and FERC-regulated wholesale competition. Still other states retain vertically integrated monopolies that look very similar to those that predominated for most of the past century.

In sum, three competing models have emerged:

- Subject to regulation by states or local public power boards, the traditional vertically-integrated electric utility controls generation, transmission, distribution and resource acquisition [e.g., most of the Southeast];
- Wholesale competition is integrated with retail regulation; distribution companies manage diverse retail resource portfolios for all or most customers and meet their generation needs through procurement from competitive wholesale markets, relying on FERC to ensure nondiscriminatory transmission access and on state regulators or local public power boards to assure recovery of prudently incurred resource acquisition costs [e.g., most of the West and Midwest];
- A Regional Transmission Organization (RTO) or Independent System Operator (ISO) controls and operates transmission, distribution is managed by state-regulated distribution companies, and resource acquisition is managed by market participants, with at least some customers relying on retail competitors of utilities to meet their electric service needs [e.g, Texas and most of the Northeast].

A further complicating factor is that federally-owned, publicly-owned and cooperatively-owned utilities (many of which are essentially self-regulated and have responsibilities beyond providing power) play a substantial role in providing electricity in some regions, while they are practically non-existent in others.

None of the models can avoid the question of ultimate responsibility for providing the affordable and reliable electricity supplies that a healthy economy requires. The most competitive models assume that decisions by market participants will ultimately replace resource planning by utilities or regulators. In practice, however, few if any regulated electric distribution companies escape at least residual responsibility for ensuring the adequacy of electricity supplies. Each model preserves a

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purchased by the same utilities "at a formula-based price").

[14] For this section, I owe a substantial debt to my colleagues at the National Commission for Energy Policy, whose reports starting in 2003 include many important insights on the evolution of electricity restructuring. *See* http://www.bipartisanpolicy.org/projects/national-commission-energy-policy.

substantial role for utility-based competitive procurement of electricity resources.

IV. Getting Competitive Resource Procurement Right

I have received repeated variants over the past three decades on the following question (e-mailed most recently to me on August 20, 2010 by a correspondent with the suggestive address of "atomicinsights.com"): *"There are only three choices for reliable power in most of the US - coal, natural gas, and nuclear. Which one does NRDC support? Why?"*

Many people think this way, and a staple of energy and climate policy debates in Congress for decades has been an obsession with single-source solutions, giving way sometimes to an unwillingness to play any favorites whatever. "All of the above" has always been a widely endorsed national energy policy. But the U.S. lacks a national electric utility, and a frightening federal balance sheet means that most new electricity infrastructure will have to be financed by traditional means, supported by the security of customers' utility bills.[15] Moreover, much of the genius in resource procurement is integration of diverse resources in ever-shifting real-time conditions. This kind of expertise is nowhere to be found in the job description of any legislator or regulator. Consider, for example, one major electricity supplier's summary of its 2010 resource plan, which effectively repudiates both single-source and "all of the above" thinking:

"Most of [our] incremental energy needs for the next several years can be met by meeting [our] conservation targets . . . and relying on short- and mid-term market purchases In addition to relying on conservation, [we] plan to continue to:

- "Rely on short- and mid-term wholesale power market purchases.
- "Facilitate the effective, efficient and reliable integration of renewable resources to [our] system through the efforts of the Wind Integration Team.
- "Increase transmission grid operating flexibilities, develop Smart Grid technologies and directly involve electricity users through demand response programs.
- "Track, evaluate and appropriately pursue availability of pumped storage and natural gas-fired resources for seasonal heavy load hour energy and/or balancing reserves."[16]

A. Navigating Industry Restructuring Models

For utility systems with needs like these – which is to say essentially all of them – the rules for cost responsibility and recovery must be clear. For example, when and on what terms may distribution utilities enter into long-term contracts with generation service providers? How will distribution utility responsibilities interact with the opportunities created for competitive retail suppliers in states with retail competition? Who has the

15 Matters are otherwise, of course, in places like China, France and Russia, where national governments still routinely choose and finance electricity resources.

16 The supplier in question is the Bonneville Power Administration, which sent out the quoted summary of its resource plan in the form of a mass e-mail communication from John Taves, *BPA Issues Final Resource Plan* (Sept. 13, 2010).

responsibility for identifying needed enhancements to the transmission network? How will transmission providers be paid for securing them, and who will pay?

In states that do not have retail competition, the possibility of its introduction and stranded costs can still deter long-term commitments, even though the alternative – reliance on short-term purchases – exposes consumers to more market volatility and deters investment in new generation and infrastructure. Utilities, regulators and wholesale suppliers alike are struggling with how states can regulate retail electric service provided by companies that operate in wholesale power markets. All lack adequate assurance about the rules that will determine commercial survival and success.

My view is that the various utility models each allow for a durable solution, in the form of competitive resource procurement and integration by regulated electric distribution companies. Energy efficiency should be treated as a resource for this purpose, and regulators' primary aim should be to ensure an acquisition process open to all, with results that minimize the life-cycle cost of reliable electricity service while meeting society's environmental goals. Success is imperiled primarily by three eminently avoidable temptations, which are addressed below.

B. Preventing Governments from Trying to Pick Winners

The mantra of California-style electric industry restructuring circa 1996 was "the genius of the marketplace": neither utilities nor their regulators should choose electricity resources, which would instead emerge in the desired configurations and amounts as a result of individual choices in competitive retail markets.[17] The conspicuous failure of this paradigm, while not yet universally acknowledged, is visible in the failure of competitive retail markets in ensuing years to deliver enduring changes in the electric resource landscape.[18] Significant generation and grid enhancements require that utilities step forward with the necessary long-term commitments.

This may tempt legislators who favor particular resources look for ways to conscript utility bills and dictate utility resource decisions. These have ranged lately from rhetoric about building 100 nuclear plants to guaranteed multi-decade payments for large-scale renewable energy resources at fixed above-market rates, set by governmental fiat rather than competitive procurement.[19]

Regulators' aim should be to ensure an acquisition process open to all, with results that minimize the life-cycle cost of reliable electricity service.

[17] *See, e.g.*, Calif. Pub. Util. Commn, Decision 95-12-063 (Dec. 20, 1995), as modified by Decision 96-01-009 (Jan. 10, 1996), at p. 8.

[18] *See, e.g.*, Nat'l Comm'n on Energy Policy, *Reviving the Electricity Sector* (Fall 2003), at 1 (describing the "challenge in reviving capital flows" in light of the fact that "electric-industry restructuring has derailed"); Electricity Advisory Committee to the U.S. Dept. of Energy, *Keeping the Lights on in a New World* (Jan. 2009).

[19] The call for 100 new nuclear plants appeared prominently, for example, in the energy policy

In urging against such interventions, however well intended, I mean no disparagement of efforts to set performance goals, such as those expressed in terms of cost-effective energy efficiency targets, acquisition rates and production-based incentives for renewable energy, and caps on greenhouse gas emissions. Legislators and regulators have every right to establish such goals and hold utilities accountable. But they should avoid usurping utility management responsibility for minimizing the costs of achieving societal targets, for at least one good reason beyond their obvious lack of expertise: In most instances they cannot be held accountable for ensuing failures, while the utility can and will be.

C. Avoiding Paralysis in the Face of Climate Policy Uncertainty

How can utilities manage long-term resource procurement when they don't know the future cost of greenhouse gas emissions? Hopes have faded that Congress would moot this question in 2010 with comprehensive legislation. But utilities have demonstrated repeatedly that they can build compelling resource portfolios while avoiding long-term commitments to resources that carry with them significant greenhouse gas emissions. One obvious element of that strategy is embodied in a Washington State law that prevents utilities from making long-term financial commitments to baseload fossil-fuel resources with emissions per kWh that exceed those of a high-efficiency natural gas generator.[20] Federal legislators and regulators can and should let carbon price signals inform electricity markets, but in the meantime utilities do not lack for investments that make sense across a wide range of potential outcomes. Leading that list, of course, are the cost-effective energy efficiency improvements that pervade every sector of the economy.[21] Exploiting them requires urgent attention to some unfinished business in utility rate regulation.

D. Removing Stubborn Barriers to Energy Efficiency

More than 30 years ago, state utility regulators began to recognize that traditional utility regulation had to change in order to put energy efficiency opportunities on an equal footing with generation alternatives. Writing for the majority in a 1975 case addressing the revenue needs of the Pacific Gas and Electric Company, Commissioner Leonard Ross anticipated issues with which many states still wrestle today:

agenda for the McCain Presidential campaign in 2008. *See* Nuclear Energy Insight (Nuclear Energy Inst., Oct. 2008) at 3 (noting also that the McCain platform "calls for 45 new nuclear plants to be built by 2030"). For some unpleasant unintended consequences of excessive governmental intervention in renewable and other energy markets, see R. Minder, *As Spain Struggles, Energy Plan Proves Difficult to Agree On*, N. Y. Times (Global Bus., Sept. 22, 2010) .

20 *See* Revised Code of Washington (RCW), sec. 80.80 *et seq.* California's SB 1368 (2006) embodies the same policy (codified at CA Public Utilities Code section 8340 et seq.).

21 For illustrative additional resource categories, see the BPA resource plan summarized above, and the Northwest Power and Conservation Council's Sixth Northwest Conservation and Electric Power Plan (2009) (available at http://www.nwcouncil.org/energy/powerplan/6/default.htm).

> We regard conservation as the most important task facing utilities today. Continued growth of energy consumption at the rates we have known in the past would mean even higher rates for customers, multibillion dollar capital requirements for utilities, and unchecked proliferation of power plants . . . . Reducing energy growth in an orderly, intelligent manner is the only long-term solution to the energy crisis.
>
> At present, the financial incentives for utilities are for increased sales, not for conservation. Whatever conservation efforts utilities undertake are the result of good citizenship rather than profit motivation. We applaud these efforts, but we think the task will be better accomplished if financial and civic motivations were not at cross purposes.[22]

Although few if any state utility regulators contest the objective of substituting less costly energy-efficiency savings for more costly alternative energy supplies, most utilities still automatically incur financial harm when electricity and natural gas use decline, and most utilities still are denied any earnings opportunities if they make cost-effective efficiency investments. The result is a broken business model: utilities typically suffer immediate losses with no prospect of gain if they try to help their customers achieve energy savings, through either targeted incentives or support for improved government efficiency standards. In deciding whether to invest in measures that reduce energy sales or more expensive energy resources that support sales growth, the utility starts with an obvious but wholly preventable conflict of interest.

Commissioner Ross and his successors long ago grasped the need to prevent changes in customers' energy use from affecting utilities' financial health. Much of a typical utility's cost of serving customers is independent of energy use (e.g., paying for generation, transmission and distribution equipment that is already installed). Since utilities recover most of their fixed costs of service through charges on electricity and natural gas use, increases or reductions in consumption will affect fixed cost *recovery* even though the costs themselves don't change. Fixing this problem includes making sure that fluctuations in sales (either up or down) do not result in over- or under-recovery of utilities' previously approved fixed costs.

Few state utility regulators would argue the objective of substituting less costly energy-efficiency savings for more costly alternative supplies.

The immediate temptation is to respond by converting fixed costs into fixed charges; this would make the recovery of fixed costs independent of energy sales, but it also would significantly reduce customers' rewards for

[22] California Public Utilities Commn, D. 84902 (September 16, 1975), quoted in B. Barkovitch, *Changing Strategies in Utility Regulation: The Case of Energy Conservation in California* (doctoral dissertation, Univ. of Calif., 1987) at 134-35.

reducing energy use. That is a step in the direction of what might be termed "all you can eat" rates, which reduce or eliminate customers' rewards for saving energy by making the bill largely or wholly independent of total energy consumption. What we need now is not rate designs that encourage electricity waste, but a strong move in the opposite direction to inverted rates, where the rule is "the more you use, the more you pay."

Of course, that means that utilities will go on relying on variable charges to recover all or most authorized fixed costs of service, which on the face of it perpetuates the disincentive for utilities to promote energy efficiency. A straightforward solution, sometimes called "decoupling," is to use small, regular rate adjustments to prevent over- or under-recovery of authorized costs. Thanks to Commissioner Ross and his colleagues, California had such mechanisms in place for both electric and natural gas utilities by 1982.[23]

[23] J. Eto, S. Stoft and T. Belden, *The Theory and Practice of Decoupling* (Lawrence Berkeley Laboratory, LBL-34555, Jan. 1994) at 21. The first formal decoupling proposal appears in testimony filed with the California Public Utilities Commn by William B. Marcus and Dian Grueneich (now a commissioner) in April 1981, as follows: "Total base revenues for forecast sales and base revenues resulting from actual sales would be compared on a quarterly basis.... The resulting undercollection or overcollection would be placed in a balancing account, rates would be adjusted to amortize the balancing account, and the balancing account would accrue interest at the prime rate." W. Marcus, *California Energy Commn Staff Report on PG&E's Financial Needs,* Application No. 60153 (April 21, 1981, Rev'd July 1981) at 55.

V. The Rise of Decoupling: A New Regulatory Bargain

A nationwide debate is underway over whether decoupling should become the industry norm. As of September 2010, 20 states had adopted such mechanisms for one or more of their natural gas utilities; the comparable figure for electric utilities was a dozen states plus the District of Columbia. Typically all that these mechanisms require is a simple monthly or annual comparison of authorized and actual fixed-cost revenues, based on readily available retail sales data, followed by small compensatory rate adjustments either up or down, which ensure that the utility keeps no more and no less than what the regulators initially approved.

Although some have worried about the impact of decoupling on electricity and natural gas rates, industry experience shows minimal effects on short-term rates, and adjustments that go in both directions. A comprehensive industry-wide assessment found that, of 88 gas and electric rate adjustments from 2000-2009 under decoupling mechanisms, less than one-seventh involved increases exceeding 3 percent. (Refunds accounted for a much larger fraction.) Typical adjustments in utility bills "amount[ed] to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month . . . for residential electric customers."[24] That represents about a dime a day for the average household, which hardly

[24] P. Lesh, *Rate Impacts and Key Design Elements of Gas and Electric Gas and Utility Decoupling: A Comprehensive Review,* Elec. J. (Oct. 2009) at 67.

seems like dangerous rate volatility, particularly since it sometimes comes in the form of a rebate – and serves only to ensure that the utility recovers no more and no less than the fixed costs of service that regulators have reviewed and approved.

These modest impacts also rebut arguments that decoupling should result in reductions in utilities' return on equity (ROE), based on the claim that decoupling appreciably reduces business risks. No support for this proposition emerges from the early history of revenue decoupling, which first gathered momentum in the late 1980s through forums

It's good not to lose money when you help your customers save energy and reduce pollution, but it's better, for both shareholders and society, if management is rewarded when it succeeds.

and inquiries led by the National Association of Regulatory Utility Commissioners. Ironically, in an early NARUC manual addressing revenue decoupling, and an early NARUC Resolution in Support of Incentives for Electric Utility Least-Cost Planning, return-on-equity issues are addressed solely from the perspective of ensuring that "successful implementation of a utility's least-cost plan is its most profitable course of action."[25] There is no mention of linking revenue decoupling to *reductions* in utilities' authorized return on equity. I can affirm from my own extensive involvement in these early efforts that this would have struck all involved as both counterproductive and counterintuitive.

Recommendations for ROE reductions more recently have been unencumbered by any empirical evidence that revenue decoupling has changed any utility's cost of capital by "reducing risks." These recommendations overlook both what shareholders give up when utilities lose the capacity to profit from electricity sales increases, and what customers stand to gain from accelerated progress in energy efficiency (and protection from higher utility bills linked to extreme weather). Any gains to utilities in the form of insurance against lower sales are offset by reduced opportunities for financial gains when sales increase, and it seems unreasonable to prejudge how that tradeoff might affect the company's overall risk profile and cost of capital.

Fortunately, commissions typically have not linked revenue decoupling to reductions in ROE. Aside from Maryland and the District of Columbia, I am aware of only one downward adjustment associated with revenue decoupling for an electric utility – the 10 basis point (0.1 percent) adjustment for Portland General Electric that the Oregon Public Utility Commission adopted in January 2009 in a severe recession. As to the District of Columbia, although a recent revenue

[25] *See* D. Moskovitz, *Profits and Progress Through Least-Cost Planning* (NARUC, Nov. 1989); the NARUC Resolution dated July 27, 1989 is Appendix C to that document. The document itself is available at http://www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf.

decoupling order reduced PEPCo's ROE by 50 basis points, it noted that the company's decoupling application did not include any enhanced energy efficiency efforts.[26]

On the other hand, the Maryland Public Service Commission recently ordered a 50 basis point ROE reduction for PEPCo and Delmarva, subsidiaries of PEPCO Holdings, based on contentions that revenue decoupling reduced financial risks for the utility.[27] In these decisions, the Maryland Commission is an outlier among its peers. I hope it will reconsider its policy, particularly given the crucial utility role in achieving new statewide efficiency targets that are among the nation's most aggressive.[28]

Assuming that utility regulators steer clear of Maryland's mistakes, widespread revenue decoupling would eliminate a huge financial disincentive for utilities to promote energy efficiency. However, it does not by itself give utilities an opportunity to share in the benefits of energy efficiency improvements. It's good not to lose money when you help your customers save energy and reduce pollution, but it's even better, for both shareholder and society, if management is rewarded when it succeeds.

To sustain their excellence in efficiency, the investor-owned utilities that deliver three quarters of the nation's electricity and almost all of its natural gas need more than just protection from instant pain. California is one of about a dozen states that have acted to assure that independently verified net energy efficiency savings to customers will also yield a reward for utility shareholders.[29] One option is to allow utilities to earn a rate of return on approved efficiency expenditures that is equal to or greater than the compensation afforded prudent generation or grid investments. My preference, however, is a compensation system tied to verified performance in delivering cost-effective savings to customers, rather than just "tonnage of capital committed."[30]

VI. Conclusion

John Rowe, Exelon's eloquent CEO, has been memorably dismissive of those offering energy solutions that "will scratch any itch you think you have." And the world will always be full of energy theologians who petition policy makers to favor their preferred technology. My case for competitive resource procurement by America's electricity distribution companies is based on a different principle, enunciated decades ago by a regulator who still ranks among the best: "Buy only what you need, and buy it as cheaply as possible."[31] ■

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[26] *See* Pub. Util. Commn of D.C., Case No. 1053, Order No. 15556 (Sept. 28, 2009), at 7.

[27] *See, e.g.*, Order No. 83516 (Aug. 6, 2010) at 55.

[28] The EmPOWER Maryland Energy Efficiency Act of 2008 aims to reduce per capita electricity consumption by 15 percent by the end of 2015, based on a 2007 baseline.

[29] For a compendium of precedents, *see* (http://www.edisonfoundation.net/iee).

[30] I first heard this characteristically vivid comparison from Tom Page, then CEO of San Diego Gas & Electric.

[31] The regulator in question was Chuck Collins, an initial member of the Northwest Power and Conservation Council. For both the Collins and Rowe quotes I rely on long acquaintance and my own memory.