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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INQUIRY INTO RETAIL ELECTRIC COMPETITION	**Docket No. E-00000W-13-0135**

REPLY COMMENTS OF RETAIL COMPETITION ADVOCATES AND THE RETAIL ENERGY SUPPLY ASSOCIATION ADDRESSING RETAIL ELECTRIC COMPETITION ISSUES

August 16, 2013

I.

INTRODUCTION

Nothing in the comments filed by the opponents of retail electric competition in Arizona casts doubt on the wisdom of the Arizona Corporation Commission's ("Commission's") decision to complete an "organized and prudential examination" of the merits of choice.[1] Moreover, there is no compelling evidence presented by the opponents that should cause the Commission to not move forward with Phase 2 of this proceeding - directing Staff to develop regulations to govern a transition to and implementation of retail choice. Indeed, while citing unfounded fears and flawed studies, some opponents of choice want the Commission to prematurely abandon its effort entirely. All Arizonans will benefit from the Commission's "transparent, open, and robust" evaluation of the merits of resuming retail competition. [2] Accordingly, Constellation NewEnergy, Inc., Direct Energy Services, LLC, Noble Americas Energy Solutions LLC, (collectively, "Retail Competition Advocates")[3], and the Retail Energy Supply Association ("RESA")[4] urge the Commission to proceed with its original plan and convene an open meeting to consider the written comments filed in this docket and accept further testimony and evidence as necessary.

The reply comments offered today focus on mis-statements and inaccuracies presented in the opening comments of the opponents of retail choice, and explain the flaws in the studies cited by the opponents. In doing so, we hope to dispel groundless fears regarding retail competition that opponents are perpetuating in this proceeding and in the media. Specifically, the reply comments herein will show that:

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[1] ACC, May 23, 2013 letter to Stakeholders.

[2] See letter of July 2, 2013 from Commissioner Bob Burns to Senator Steve Pierce.

[3] Each member of the Retail Competition Advocates has an applications pending before the Commission for a Certificates of Convenience and Necessity that will, when approved, allow each to compete to provide retail electric service to Arizona customers. We anticipate that additional appplications will be submitted when the Commission moves forward with retail electric competition.

[4] RESA is a broad and diverse group of retail energy suppliers operating in 16 states delivering competitively priced retail electricity and natural gas to residential, commercial and industrial customers. For information about membership and initiatives, see: http://www.resausa.org/ RESA's members include: AEP Energy, Inc.; Champion Energy Services, LLC; ConEdison Solutions; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Hess Corporation; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

1. Benefits: Retail competition will bring benefits to all rate classes, including residential customers.

2. Coal: Retail competition cannot be blamed for problems that coal may have as part of Arizona's future energy mix.

3. FERC: Retail choice will not cause the Federal Energy Regulatory Commission to usurp the Commission's authority; the ACC will retain authority over Arizona's energy policies.

4. Constitutionality: The process and legal issues identified in the *Phelps Dodge* decsion are easily avoided or resolved through Commission process; no constitutional amendments are necessary

5. Reliablity: Neither retail electric competition nor the resulting design of utility POLR service[5] (or any default service design) creates reliability risks for the Arizona electricity grid; such claims are pure fiction.

6. Stranded Costs: Retail competition does not create stranded costs but merely reveals the above market prices being paid by customers due to uneconomic investment and operating expenses associated with monopoly service.

7. Implementation Cost: Retail choice implementation costs have proven to be trivial relative to benefits in competitive jurisdictions.

8. Market Misconduct: Retail competition among alternative suppliers has had nothing to do with recent FERC action to settle and/or impose penalties with respect to wholesale market behavior.

The resumption of retail electric competition and customer choice are overdue in Arizona. Customers are being denied energy cost savings, product advancements and service innovation by the current regimen of monopoly providers and bundled tariff services. The Commission has quite properly decided to re-evaluate retail electric competition in light of more than a decade of customer choice success in other states.

When the Commission and Staff conclude their review of the initial comments and these reply comments, Retail Competition Advocates and RESA urge the Commission to direct ACC Staff to:

- Develop and/or modify existing retail market rules and protocols to ensure an efficient and robust competitive market framework; and

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[5] In these reply comments, Retail Competition Advocates and RESA respond to issues raised with respect to the POLR service provided by the utilities. However, as noted in their initial comments, Retail Competition Advocates and RESA do not support the idea that POLR service must or should be provided by the utilities.

- Address and remedy the procedural and legal deficiencies that resulted in the rules being suspended, as was contemplated by the Commission at the Open Meeting held on May 9, 2013.

II.
Reply Comments

1. Retail competition will bring benefits to all rate classes, including residential customer.

Opponents of retail choice – primarily the incumbent utilities and AARP – would have the Commission believe that there is no need or good reason to allow their captive ratepayers to explore supply alternatives – that there is not enough benefit to justify further exploration of retail electric competition. Specifically, opponents of retail choice consistently contend that residential customers have little interest in retail choice, will see little or no benefit from it, and indeed that the cost savings enjoyed by commercial and industrial customers in a retail choice market come at the expense of residential customers. Retail Competiton Advocates and RESA will clearly demonstrate that the evidence they present to support thses contentions is factually deficient and analytically flawed – and easily refuted.

- **Opposition Claim: Residential customers pay more under retail choice than they do under rate regulation**

There are three primary pieces of evidence that opponents use in an attempt to support this claim, a study prepared by the American Public Power Association ("APPA") ("APPA Study), [6] a study prepared by the Texas Coalition for Affordable Power ("TCAP Study"),[7] and various compilations of data from the Energy Information Administration ("EIA"). Each of these pieces of evidence is flawed and rebuttable.

The APPA Study: The APPA Study data is referenced in the initial comments of various different parties, including APS, AARP, the Navajo Nation, SRP, and TEP. Among other things, the APPA Study purports to compare the "average revenue per kWh" in regulated vs. restructured states between 1997 and 2012 and shows that during the study period customers in restructured states paid on average 3 cents more per kWh than have customers in states that have not restructured (11.9 cents per kWh versus 8.9). There are, however, substantitive flaws in the methodology used by APPA to reach its conclusions.

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[6] American Public Power Association (APPA), *Retail Electric Rates in Deregulated and Regulated States: 2012 Update*, available at:
http://www.publicpower.org/files/PDFs/RKW%5FFinal%5F%2D%5F2012%5Fupdate.pdf

[7] *See "Deregulated Electricity in Texas, A History of Retail Competition - The First* 10 *Years, Appendix C: Electricity Complaints under Deregulation,"* Texas Coalition for Affordable Power, found at http://historyofderegulation.tcaptx.com/chapter/appendix-c-electricity-complaints-increase-underderegulation/,
accessed June 26, 2013.

First, APPA calculates average retail rates by "dividing total annual revenue from sales to consumers by total annual sales to consumers." This melting pot approach mutes the variations that exist between utility default rates and competitive rates across multiple rate classes, such as the pricing impact of value added services that competitive retail suppliers provide and fails to look at the true measure of the value of competitive shopping which is the change in rates customers have seen since the implementation of a competitive choice.. Second, APPA includes data from markets such as California, Michigan, and Oregon that have caps or limits on shopping under the current market design, folding them into the "averaging" methodology above. This approach fails to account for the fact that much of the revenue and many of the sales included from these states actually belong on the regulated states side of the calculation. Third, APPA's data entirely ignores Texas in the accounting for "deregulated states" category altogether. Texas, as has been cited earlier in this filing, is regularly cited as the most successful state at implementing competitive retail choice with 100% (5.5 million residential customers and 987 thousand commercial and industrial customers as of the end of 2012[8]) of all customers shopping for electric service.

While this broad brush approach allows APPA to attempt its claim that customers in restructured states are paying more on average that customers in states that did not restructure, (and as such lets the Arizona opponents cite it to support their opposition), it hardly presents any useful analysis. A much more accurate approach is to compare actual utility default rates to actual competitive offers in those markets. This is precisely the analysis that Retail Competition Advocates and RESA presented in Tables 1 and 2 of our initial comments, which compare utility rates in various jurisdictions to competitive offerings for a representative month for fixed/monthly priced products and renewable/wind/green products respectively.

Another much more accurate compilation of price comparative data was prepared by the COMPETE Coalition. COMPETE's study – a thorough analysis of the EIA data from 1997 through 2012, adjusted for inflation, demonstrates that customers in restructured states (residential, commercial, and industrial each shown separately) have experienced a lower rate of increases in electric rates since the implementation of competitive retail choice. This measure is important because current rates can be reflective of decades of past economic and regulatory decisions not associated with competitive alternatives. The most important fact to consumers is what they can expect moving forward and this analysis shows Arizona consumers that they can expect the lowest available cost for electric service in addition to access to various value added services that have been discussed in this filing This data was presented by the Retail Competition Advocates and RESA in their initial comments, and the COMPETE study was included as Attachment A2.

The TCAP Study: AARP says that the TCAP Study shows that "Electricity prices above the national average have cost Texans more than $11 billion during the 10-year history of retail competition."[9] Interestingly, AARP's footnote to support this alarming statistic references an update to a study prepared by TCAP in 2009 that, as far

[8] See DNV KEMA, KEMA Retail Energy Outlook Q4'12 February 5, 2013, p24 which is available by subscription,

[9] See AARP initial comments, page 21.

as Retail Competition Advocates and RESA can ascertain, makes no such statement. APS makes a similar claim: "Electric restructuring has cost Texas residential consumers more than $11 billion in higher rates."[10] APS's footnote for this claim references a news article of February 15, 2011 written by Jack Smith and published in the Star-Telgram.[11] That news article in turn references separate TCAP study completed in February of 2011, a 101 page missive entitled "The Story of ERCOT" that on page 84 and 85 describes the calculation made to arrive at the $11 billion dollar figure. It says: "Had electric prices remained at the national average — not below it, just at it — Texas residential consumers would have saved more than $11 billion since the implementation of deregulation, according to the federal data." [12]

To claim that customers in Texas would have paid less had prices in Texas been at a national average, and that the fault for prices in Texas being above a national average lies with retail choice, is utterly devoid of any analytical rigor, and does a disservice to this Commission's geniune inquiry into the benefits of retail choice. It is no wonder that APS and AARP wanted it to be difficult to find the source of the $11 billion dollar number – exposing the genesis of the number undermines any credibility that it has to sound the alarm against retail competition. It deserves to get no further attention from this Commission, except for a recognition that such specious use of date undermines to the core the credibility of the parties who have relied on it – in short, it demonstrates only the lengths to which they will go to convince the Commission to abandon consideration of retail choice.

The TCAP study so misleadingly referenced by AARP and APS also purports to shows that residential ratepayers in restructured jurisdictions in Texas are paying more than residential ratepayers in regulated or municipality jurisdictions; that argument, too suffers from flaws that render it meritless in proving that residential customers pay more with choice. These flaws are fully exposed in a response prepared by the Association of Electric Companies in Texas ("AECT"). The preamble to AECT's response to the TCAP study states:

> It is built on a fulty premise that ignores the impact of natural gas prices and infrastructure investment while choosing a 1999 base year for multiple comparisons which simply does not make sense.
>
> Additionally, it relies on data that does not accurately reflect the competitive market or the role of customers in choosing products that meet their needs. As shown below, TCAP selectively provides only

[10] See page 3 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring f APS

[11] http://www.star-telegram.com/2011/02/14/2848532/study-tallies-cost-of-deregulation.html

[12] See The Story of ERCOT, page 85; found at: http://tcaptx.com/downloads/THE-STORY-OF-ERCOT.pdf

> pieces of the statistical story behind electricity prices in ERCOT in hopes that its audience will draw an erroneous conclusion.
>
> These conceptual and statistical failings are endemic throughout TCAP's analysis of the competitive electric market.[13]

The AECT response then goes on to fully dissect each of the following flaws in the TCAP Study:

1. TCAP Largely Ignores the Impact of Natural Gas Prices
2. TCAP Chooses its Baseline Data to Pre-Eneginneer its Findings:
3. TCAP Often Relies on EIA Statewide Data for its Comparison:
4. TCAP Does Not Take Into Account Offers Available in Competitive Areas.
5. TCAP Does Not Account For, or Even Evaluate Structural Differences Between Competitive and Non-competitive Areas of Texas.
6. TCAP Mistakes State Boundaries for Power Market Boundaries
7. TCAP Ignores Other Benefits of Choice in the Competitive Market
8. TCAP fails to Consider the Impact ofNew Investment to Meet Population and Economic Growth

The AECT response contains all the detail necessary to completely and fully refute the TCAP study, and is attached to these comments. Again, it is necessary to note that reliance by opponents of retail choice on a study that has such little credibility exposes the fact that there opposition to retail choice is entirely misguided, and represents a desire to maintain the outdated vertically integrated utility structure to the detriment of residential and commercial/industrial customers who are interested in managing their own energy choices.

EIA data: In its opening comments, AARP also included a table entitled "Alternative Supplier" vs. "Full Service Supplier" prices, which they say compares rates paid by residential load for provider of last resort service (POLR) also know as default service to regulated utility rates in non-restructured states. AARP contends that this data "documents a trend of higher prices charged by alternative suppliers." [14] Data compiled by the Energy Information Administration ("EIA") is the source data for the AARP table.

As is the case with the APPA study and the TCAP Study, this approach is flawed in that it does not take into account differences between the services provided under choice versus default service, and therefore paints an overly simplistic and inaccurate picture. While it allows opponents of retail choice to make broad statements about the lack of benefit associated with retail choice, the analysis has fundmantal flaw that expose it for what it is – a disingenuous attempt to manipulate data to present a claim that is misleading. The correct way to compare prices is recognize the retail choice allows customers a range of services – reference back to Table 3 in the initial comments of the

[13] See Attachment 1, AECT Comments on the Texas Coalition for Affordable Power's (TCAP'S) Views on Electric Prices in the Competitive Electric Market.
[14] See AARP opening comments, page 6.

Retail Competitive Advocates and RESA which shows the brorad range of products and services that are available to retail customer – and then compare the range of price options that are offered to customers in restructured markets to the utility default rate in such markets, which is precisely what the Retail Competition Advocates and RESA provided in Table 1 of their July 15, 2013 opening comments. It shows that customers in restructured markets have a range of offers priced below the default option, with open markets bringing multiple retailers and offers to customers.

APS's CEO has made similarly misleading statements when he contends that "Arizona's electricity rates are below market. Electricity rates in the state are lower than the national average [as calculated by EIA data] and are lower than rates in nearly all deregulated states, according to the U.S. Energy Information Administration."[15] This contention conflates being below the "national average" with being "below market," and presents a tempting soundbite that in reality conveys no meaningful information. For APS to claim that its rates are below market, they must compare their rates to an Arizona market price, which it has not done.

- **Opposition Claim: Retailer suppliers "cherry pick" the largest customers; the promise of new pricing options and services has not materialized for residential and small commercial customers and that residential customers are left on utility service to pay an ever increasing share of utility costs as commercial and industrial move to retail choice.**

APS's comments with respect to cherry-picking[16] are representative of the type of claim that several opponents of retail choice make in their opening comments with respect to alleged cherry-picking. The section above refuting the claim that residential customers do not benefit from retail choice likewise dispels any notion that retail markets are not offering valuable options and services to residential customers.

Equally flawed are claims that residential customers are being required to bear an increasing share of utility costs as competitive suppliers' cherry-pick more lucrative commercial and industrial customers. Indeed, no one would disagree that such an outcome must be avoided, which is why it has been avoided in every jurisdiction that allows retail choice, and can easily be avoided in Arizona. Simply put, once the decision to provide any class of customers ACCESS to the benefits of choice, the Commission can readily turn its attention to ensure that this ACCESS to choice and its savings and innovation, does not harm those who inexplicably decline to take advantage of these choices. The potential for load migration away from utility service (and back to it) requires a different sort of procurement planning, for which the POLR auction approach described by the Retail Competition Advocates and RESA in their initial comments and

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[15] http://www.energychoicematters.com/stories/20130805b.html

[16] See APS opening comments, page 6 where they state: "...marketers have focused on the largest customers and on those customers that have load characteristics that are less expensive to serve than the rest of their rate class. This "cherry picking" of the most desirable customers leaves behind and increases the cost to serve all other customers, including residential and small commercial consumers."

as discussed further in Section 5 below is very well suited to the extent any form of default service exists.

- **Opposition Claim: Switching rates not high enough among residential customers in other markets.**

APS would have the Commission reject retail choice because residential switching has been lower than the switching rates for other classes of customers.[17] However, the data presented by the opponents does not reflect the most recent data. As Retail Competition Advocates and RESA presented in our initial comments, more recent data shows a growing trend for residential switching activity. In fact, according to KEMA's Energy Outlook 2013, there are, as of the end of 2012, nearly 14 million residential customers nationwide being served through retail choice,[18] including service from members of the Retail Competiton Advocates and RESA. According to the KEMA report, this represents 27% of all residential customers eligible for retail service, and represents an increase of 28% from the previous year continuing 4 year trend of increases in residential shopping.

Some further examples of the growth in residential retail service bear mentioning as well. For example, in Maine and New Hampshire alone, residential customers long thought to be uninterested and inactive with respect to choosing alternative suppliers, has seen residential switching increase by 700%, as customers there have begun to exercise their ability to choose among retail options and competitive switching. The same was true in 2012 in Illinois and Ohio. While the residential retail market continues to evolve, the fact that this evolution is slower than for other customer classes is no reason to deny them the ability to choose. Allowing choice to residential customers is to their benefit, and it is absurd to argue that no residential customers should be given that option because not all take advantage of it.

- **Opposition claim: Low income customers will not see the benefits of competitive choice.**

Under any regulatory structure, programs that assist vulnerable members of our society are necessary. Neither maintaining the status quo nor implementation of retail choice will eliminate the need for society to assist them. Nevertheless, the fact that low income customers will continue to need assistance is certainly no reason to reject retail choice. Many low income customers are no less capable of making informed choices about their energy usage than other customers, and should not be precluded from participating in retail choice programs. Retail Competition Advocates and RESA believe that for these customers to maximize their benefits not only should they have access to retail competition but any available funding for these customers should be portable so that they are not hindered or limited in the options they have in a competitive market.

[17] See page 1of 35 of APS Exhibit A: APS Response to Staff Electric Restructuring Questions.
[18] See KEMA Retail Energy Outlook 2013, which is available by subscription.

The specifics of determining how low income customers particpate in retail choice programs is a eminently worthy issue for Phase 2 of this proceeding, and should be fully considered at that time.

Summary: Having refuted the claims and faulty analysis put forth by the opposition to suggest that retail choice does not have benefits for customers, particularly residential customers, Retail Competition Advocates and RESA conclude this section of our comments with some clear statements of the benefits and general acceptance that retail choice is gaining throughout the nation – each of the following reports and articles is attached:[19]

1. COMPETE chart on rate of change: http://www.competecoalition.com/files/EIA%20restructured%20states%20data%20chart%20March%202013%20update.pdf
2. J.D. Power Survey Finds High Degree of Customer Satisfaction in Texas' Competitive Electricity Market: http://www.jdpower.com/content/press-release/tvd8ptM/2012-texas-residential-retail-electric-provider-customer-satisfaction-study.htm
3. J.D. Power Survey Finds that Customer of Texas Retail Electric Providers are More Satisfied Than Customers of Regulated Utilities, Driven Primarily by Price: http://www.jdpower.com/content/press-release/kVNNnIQ/2013-texas-residential-retail-electric-provider-customer-satisfaction-study.htm
4. Texas Public Policy Foundation paper (attached) "Prices, Reliability, and Consumer Choice in the Texas Electricity Market": http://www.texaspolicy.com/center/economic-freedom/reports/prices-reliability-and-consumer-choice-texas-electricity-market
5. Chicago Daily Herald: "$31 billion in benefits, and counting" http://www.dailyherald.com/article/20121227/discuss/712279988/print/
6. Latest statistics from the Illinois Commerce Commission's Office of Retail Market Development: http://www.icc.illinois.gov/downloads/public/2013%20ORMD%20Section%2020-110%20report.pdf
7. Dr. William Hogan and John Chandley "Electricity Market Reform: APPA's Journey Down the Wrong Path": http://www.hks.harvard.edu/fs/whogan/Chandley_Hogan_Compete_041609.pdf; http://www.competecoalition.com/files/LECG%20Fact%20Sheet.pdf
8. COMPETE Report: Residential Customer Switching Drives Big Upsurge in Retail Electricity Competiton:

[19] See Attachments 2 through 10.

http://www.competecoalition.com/blog/2013/02/residential-customer-switching-drives-big-upsurge-retail-electricity-competition

9. COMPETE: "Pennsylvania electricity market surpasses 2 million shopping customers" http://www.competecoalition.com/blog/2013/02/pennsylvania-electricity-market-surpasses-2-million-shopping-customers

2. Retail competition cannot be blamed for problems that coal may have as part of Arizona's future energy mix.

If coal's position in Arizona's future energy mix is problematic, it is because environmental issues and initiatives are causing the cost of using coal to increase, and is not due to the prospect of retail customer choice.

Several sets of initial comments contend that the resumption of retail choice in Arizona will trigger the demise of the coal industry in Arizona, causing it to collapse under the uncertainty that retail choice has allegedly created for two prominent coal-fired facilities in Arizona, the Navajo Generating Station ("NGS") and the Four Corners Power Plant ("Four Corners").

Most bombastically, Arizona Public Service Company ("APS"), calls the Commission's consideration of retail electric competition a "war on coal"[20] and argues that the "Four Corners Power Plant and Navajo Generating Station are at particular risk of closure if the Commission pursues electricity deregulation."[21] In its initial comments, the Navajo Nation categorically states: "....if the Commission proceeds with its inquiry into retail electric competition, the Navajo Nation and Arizona ratepayers will face severe economic consequences right away. The two largest coal plants serving Arizona (the FCPP and Navajo Generating Station, or "NGS") and the coal mines that serve them will shut down."[22]

Salt River Project Agricultural Improvement and Power District ("SRP") less colorfully, yet equally inaccruately, argues that allowing retail competition will deter investment in NGS:

> We will not have the organizational capacity to get this job done if [we] have to deal, yet again, with deregulation. Moreover, the investment that will be necessary to create a reasonable future for NGS will simply likely not be made given uncertainty as to SRP's load (retail demand) and attendant revenues. We expect the investment to be substantial, and that deregulation would make the investment risk too big.[23]

[20] See page 2 of APS's cover letter.
[21] See page 21 of 21 of APS's Initial Response to Commision's inquiry Regarding Electric Restructuring
[22] See page 1 of the Navajo Nation initial comments.
[23] See cover letter of SRP opening comments (no page numbers)

The arguments presented by APS, the Navajo Nation, and SRP – that the resumption of retail choice will determine coal's future in Arizona – are without merit. In reality, Arizona's coal industry – as in other states – faces the hard fact that coal generation is highly likely to become much more expensive over time as such facilities are obliged to address new environmental pressures[24] and mandates. The future of NGS and Four Corners will be dictated by these national and state environmental policies,[25] independent of the Commission's decision as to whether to resume retail electric competition. Keeping a monopoly market structure will not change the challenging economics of coal.

The fact that retail choice is not the culprit in determining the future of coal in Arizona is further illustrated by SRP's recent agreement to invest in controlling NGS' pollutant emissions. A mere 10 days after submitting its opening comments in this proceeding, SRP, the Navajo Nation, the Central Arizona Water Conservation District ("CAWCD"), the U.S. Department of Interior, and other stakeholders executed their *Technical Work Agreement Related to Navajo Generating Station (NGS)*.[26] The Agreement calls for the parties to jointly urge the U.S. Environmental Protection Agency ("EPA") to adopt a "reasonable alternative" to the agency's proposed pollution control measures, known as Best Available Retrofit Technology. Among other things, the agreement spells out how and when NGS will transition away from coal. That settlement undoubtedly represents some very difficult choices for the members of the stakeholder working group that came together to develop this settlement proposal. If the settlement is adopted, and costs associated with keeping NGS in operation are higher than alternative sources of power that may be available, there may well be charges imposed on all Arizonans in the form of non-bypassable charges; if so, those charges will be paid by all customers.

Four Corners is another story. APS' argument that retail competition might doom its proposed \$294 million acquisition of Southern California Edison's 48 percent interest in Four Corners Units 4 and 5 also protests too much.[27] APS has reported to the Securities and Exchange Commission that:

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[24] The following is a link to the EPS Mercury and Air Toxics Standards: http://www.epa.gov/mats/

[25] The U.S. Department of the Interior's Bureau of Reclamation picked AECOM to prepare a third-party environmental impact statement for the continued operation of the Navajo coal-fired power plant and Kayenta Mine Complex, operated by the Salt River Project and Peabody Western Coal Co., respectively. The operation of the plant and mine require compliance with dozens of federal and tribal regulations, and jurisdictional approvals from approximately 10 cooperating government agencies." AECOM picked for environmental study of Navajo plant & coal mine, Power Engineering, August 7, 2013, http://www.power-eng.com/articles/2013/08/aecom-picked-for-environmental-study-of-navajo-plant-coal-mine.html

[26] Available at http://www.doi.gov/upload/7-25-2013-NGS-TWG-Agreement-FINAL_Executed.pdf

[27] The proposed transaction is described in APS' November 8, 2010 Form 8-K, available at http://precisionir.api.edgar-online.com/EFX_dll/EdgarPro.dll?FetchFilingHTML1?SessionID=ORSHHHGAD_kxk1v&ID=7542311

> APS currently expects that it will not be in a position to close the Four Corners purchase transaction with SCE until the ACC's intentions with regard to pursuing deregulation in Arizona become clearer.[28]

APS appears to be suggesting that if customers are able to leave APS's supply service, it will not want or need the additional generation from the $294 million acquisition. APS's argument represents a stunning about-face from the picture it painted when seeking the Commission's approval to make the purchase in the first place. As the Arizona Competitive Power Alliance argued in its opening comments:

> APS recently filed an 8-K in which is stated that it would hold off on the purchase of the Four Corners power plant until the ACC's intentions regarding retail electric competition become clearer. The Alliance has argued that the Four Corners plant was too risky for Arizona consumers because there was no way to determine how much it was ultimately going to cost APS to comply with the constantly increasing environmental costs. We argued that APS should conduct an RFP to determine if the competitive wholesale market could provide the power or capacity at a more reasonable and predictable price. APS responded that even with the needed environmental upgrades Four Corners was the cheapest and best option.
>
> Why then would the advent of Retail Competition make APS less interested in buying the plant? After all, if the Four Corners plant was the cheapest and best option, then it would be even more valuable in a competitive environment because it would confer a competitive advantage to APS. The Alliance argued that plant was too risky and APS disagreed. However, now that captive ratepayers are no longer on the hook for any environmental cost overruns, APS is reconsidering its purchase of the plant. APS's reluctance to buy the Four Corners plant in a competitive environment is not a bug of retail electric competition, it's a feature.[29]

Put another way, APS previously told the Commission that its purchase of Four Corners would provide cost effective power for ratepayers. Now it is arguing that retail competition might render its acquisition unnecessary – that is, that other competitors would be able to undercut the price at which Four Corners can generate power. One of two things must be true. If APS' original position that the price of Four Corners power would be attractive to ratepayers is correct, then Four Corners would be able to sell all of its power even in a competitive market. If the Four Corners plant cannot sell its capacity in a competitive market, then it would not have been such a good deal for captive

[28] See Pinnacle West 8-K, dated June 17, 2013 at http://phx.corporate-ir.net/phoenix.zhtml?c=86158&p=irol-SECText&TEXT=aHR0cDovL2FwaS50ZW5rd2l6YXJkLmNvbS9maWxpbmcueG1sP2lwYWdlPTg5ODg0MTMmRFNFUT0wJlNFUT0wJlNRREVTQz1TRUNUSU9OX0VOVElSRSZzdWJzaWQ9NTc%3d

[29] See Opening Comments of the Arizona Competitive Power Alliance, page 1-2

ratepayers after all. Either way, the fair weather "for the best interest of the customer" advocacy tactics employed by APS are apparent when one looks at the utility's inconsistent arguments regarding Four Corners.

While the coal industry in Arizona faces change, there is little evidence to suggest that coal in general is on its way out as a predominant fuel source. In fact, quite the opposite is true, as demonstrated by the Energy Information Administration-923 data from the first quarter of 2013,[30] which shows:

a. Coal fired generation increased by 12.7% and fueled 41.8% percent of all electricity generation. This was facilitated in part by investments in emission controls by coal generators that allowed them to burn high-sulfur, low-cost coal while meeting EPA standards.
b. In PJM, where every single state allows retail choice, coal remains the leading source of generation at 44%.
c. In Texas, where natural gas has long reigned as the primary fuel for electrictiy, coal still owns a 34% market share.
d. In the territory of the Midwest Independent System Operator (MISO), in which there is a mix of retail choice and traditional monopoly jurisdictions, coal's share is 73%.

Additional evidence of the overall robustness of the coal industry can be found in the recent merger between GenOn and NRG, two large independent energy producers. This merger creates the largest coal-fired coal fleet. Along with other diversified resources, the newly merged company intends to use this fleet as a platform for retail expansion.[31]

If coal could talk, it would use the words of the immortal Mark Twain, and say: "The reports of my death are greatly exaggerated." The Commission should not be persuaded by the utilities fear tactics. Allowing consumers to make informed decisions will bring rigor and efficiency to electricity choice that will benefit all consumers, whether they choose an alternative supplier or not.

3. Retail choice will not cause the Federal Energy Regulatory Commission to usurp the Commission's authority; the ACC will retain authority over Arizona energy policies.

FERC Regulation: APS and others claim that that resumption of retail choice in Arizona will allow the Federal Energy Regulatory Commission ("FERC") to displace the Commission's regulatory oversight. APS says:

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[30] Data excerpted from June 21, 2013 SNL article.
[31] See Attachment 11 taken from the following link: http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MTQ2NDgyfENoaWxkSUQ9LTF8VHlwZT0z&t=1

> [I]n a deregulated environment, this Commission would lack the authority to hold those companies accountable to our customers. The Federal Energy Regulatory Commission would, instead, largely take control of Arizona's energy future.[32]

This claim is unfounded. Competitive wholesale markets, over which FERC exercises oversight functions, will broaden as there will be more buyers and sellers at the wholesale level, but the basic jurisdictional separation between FERC and the Commission will not fundamentally change as a result of retail competition. As described in more detail in the attached 2010 presentation prepared by FERC's office of General Counsel[33] and the 2010 report on Regulation and Oversight of the Electric Power Industry prepared by the COMPETE Coalition, the delineation of Federal and state authority over the electricity industry was defined by Congress in the Federal Power Act nearly 80 years ago and remains quite simple and rigid. States have jurisdiction over: (1) the rates and terms of sales to end-use customers (i.e., retail sales); (2) the distribution of electricity to end-use customers; and (3) the siting of generation, transmission, and distribution facilities. None of these state authorities change or will be limited as a result of restructuring and retail competition.

The FERC has jurisdiction over: (1) the rates and other terms of wholesale sales of electricity (defined as sales for resale) in interstate commerce; and (2) the transmission of electric energy in interstate commerce. In addition, the Energy Policy Act of 2005 gave FERC authority to ensure the reliability of the bulk power electric system, and to investigate and penalize fraud and manipulation in electricity markets. However, restructuring in Arizona would not expand FERC's Federal Power Act or Energy Policy Act of 2005 jurisdiction.

Similarly, FERC has no jurisdiction over the siting and construction of generation (other than hydroelectric generation) and transmission facilities (with the exception of so-called "backstop" siting authority under FPA 216 (16 USC 824p)); over environmental or safety matters (with the exception of hydroelectric generation-related environmental and safety matters); over state agencies and instrumentalities (including municipalities) -- with certain limited exceptions; or over cooperatives financed by the Rural Utilities Service. None of these areas where FERC has either limited or no jurisdiction change as a result of state restructuring.

Should there be a decision at the initiative of the owner of such generation that the transition to retail choice will result in the transfer of utility-owned generation to an affiliate – one of the mechanisms described in the July 15, 2013 comments of Retail Competition Advocates and RESA as a means to achieving the separation of utility

[32] See page 2 of APS cover letter.

[33] See Attachment 12: *An Overview of the Federal Energy Regultory Commission and Federal Regulation of Public Utilities in the United States* prepared by Lawrence R. Greenfield, Associated General Counsel – Energy Markets – Office of General Counsel – Federal Energy Regulatory Commission, dated December 2010, which can also be found at the following link:, http://www.ferc.gov/about/ferc-does/ferc101.pdf

supply functions from their transmission and distribution function – such a transfer would require FERC approval under Section 203 of the Federal Power Act.

In short, the Commission's jurisdiction over the utilities' distribution service will remain unchanged, and the Commission's ability to oversee regulated retail service and retail rates will remain unchanged. Arizona will retain existing authority over the siting of generation, transmission and distribution resources in the state. Both the federal Energy Policy Act of 1992 and Energy Policy Act of 2005, laws that increased FERC's authority over wholesale electricity markets, contained explicit language stating that the laws did not affect the authority of a state regarding the safety, adequacy and reliability of electric service within that state. Arizona will retain its existing authorities in these areas after the implementation of retail choice. Arizona will continue to exercise authority over state energy policy decisions regarding matters such as renewable power development, retail demand response programs, energy efficiency, or issues related to deployment of smart meters, and will have oversight for POLR service, if there is a POLR service at all. Finally, retail choice will not change the fundamental goals of FERC and the ACC, or their respective roles, with respect to an efficiently-priced, affordable and reliable supply of electricity for consumers.

Where states have clashed with FERC regulatory authority, that clash has occurred because of policies promoted by state regulatory agencies that have sought to circumvent competitive markets and mandate investments by their jurisdictional utilities that, as proposed, would clearerly undermine the workings of competitive wholesale markets. This concern about FERC intrusion into state jurisdiction has been highlighted recently by a case involving a New Jersey law that was passed to enable the state to procure up to 2,000 MW of new generation, and provide out-of-market payments to the new generation if the clearing price in the capacity market auction conducted by PJM was below the costs of the plant. PJM was concerned that this could lead to a situation where the state-backed new generation could bid into the auction at below cost (since any below cost outcome would be made up the state), causing the auction to clear at artificially low levels, and skewing market outcomes. PJM filed with FERC to implement mechanisms (referred to as the Minimum Offer Price Rule, or MOPR) that would require bids in the auction to meet certain thresholds in order to avoid artificial supression of prices caused by low-ball bids by generators whose fixed costs were already being paid for, that is subsidized, by an individual utility's customers under a state mandate. The State of New Jersey objected to FERC's approval of PJM's MOPR rules, arguing that FERC was preventing New Jersey from being able to attract new generation to its state.[34] Interestingly, all the Commissioners of Pennsylvania the Public Utility Commission have strongly supported the FERC decision, and have sent a letter to their congressional delegation urging them to rebuff any calls for new legislation to circumvent FERC's regulatory jurisdiction. The Pennsylvania Commissioners said:

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[34] See Attachment 13 where Customers pushed back on similar efforts in Maryland. http://www.competecoalition.com/resources/compete-customer-members-oppose-monopoly-utility-regulation-maryland%E2%80%9D

> Other parties have argued that FERC's decision infringes on states' rights to design their own energy policies. The PA PUC disagrees with this line of reasoning as well. Under FERC's decision, the only capacity bids that would be mitigated under the MOPR are the bids that are too low, meaning they do not reflect the actual cost of building or operating that type of capcity, and would skew the supply and demand balance that sets the true market prices. Similarly, under the FERC decision, the only capacity bids that would fail to clear in the RPM auction are ones that are uneconomic, meaning they are too expensive to build or operate. Thus, any party that wants to use or construct capacity outside of these bounds is either seeking to build uneconomic capacity or is simply trying to manipulate the markets. The rules that FERC accepted in its order ensure that the RPM market remains competitive and free of manipulation, while still leaving states free to pursue any capacity projects that are economically sound.[35]

The resumption of retail electric competition will require the Commission to implement, defend, and support competition at both the wholesale and retail levels. The Commission will have to be committed to allowing competitive market forces and customer choice to determine when and how investments are made and how the risks of those investments will be managed. Not surprisingly, Arizona's utilities prefer continuation of their vertically integrated monopoly structure that relies on cost-of service accounting, where their investment risks are initially borne by ratepayers, subject to subsequent prudency review. In the vertically-integrated/rate-regulated model, where utilities have few real incentives to manage their investment risks because the more they spend, the more return they make for their shareholders. The fact that customer choice brings a broader market perspective to Arizona – that carries with it a more active wholesale market oversight role for FERC does not mean that the Commission and other policymakers are rendered unable to set energy policy that is consistent with reliability and environmental standards. .

Ongoing Regulatory Activity: APS also states: "Restructuring is not a "one and done" activity. States that restructured 15 years ago are still fighting over the rules at FERC and in federal courts."[36] Of course restructuring is not "one and done" – any more than regulatory management of the vertically integrated monpolies is one and done. At any given point in time, the Commission has numerous dockets open on each regulated electric utility related to all aspects of regulation including rate applications, financing applications, tariff filings, and complaint dockets, each of which could remain open and active for many years to address compliance requirements and issues that arise. It is absurd to suggest that competitive retail markets should be avoided because of the need for ongoing regulatory proceedings and perhaps even occasional litigation. Controversies arise in all regulatory environments, whether monopoloy or customer choice.

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[35] See Attachment 14: Letter from PA PUC to FERC, dated July 13, 2011 at the following link.

[36] See page 3 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring

Keeping Arizona's energy future in Arizona's hands: Touting its long history of stewardship to its Arizona customers, APS's CEO calls into question whether companies not located in Arizona could or would have any similar concern for Arizona energy users. He states:

> I am convinced that companies located in other states - possibly even other countries - would lack that same sense of Arizona stewardship. And in a deregulated environment, this Commission would lack the authority to hold those companies accountable to our customers. The Federal Energy Regulatory Commission would, instead, largely take control of Arizona's energy future.[37]

APS reveals its fear of geniune competition. It is really quite stunning that the CEO of one of Arizona's largest corporations would seem to suggest that Arizona should adopt a foxhole mentality with respect to allowing out of state (or out of country) companies to do business in Arizona. Let's put aside the problem that adopting such a policy would have for the Diamondbacks and the Cardinals, as well as the Sun and Mercury in finding other teams to play against at home. Let's also ignore the problem Arizona consumers would have finding cars or cells phones only manufactured only in Arizona or television programming amd movies originating exclusively in Arizona. The simple fact, of course, is that electricity is already a major interstate business and that APS is a significant player in the Southwest's wholesale electricity market. APS's suggestion that the Commission should adopt the myopic view that it, and only it, should be the sole intermediary for power supplies from that interstate market runs counter to the fact that Arizona is the happy home to numerous out of state companies, such as Raytheon, Intel, USAA, and the multiple federal air force, army, and marine bases that reside in Arizona.

Moreover, such a stance also defies Arizona's extensive initiatives to bring new business to Arizona, such as those of the Arizona Commerce Authority whose mission is in part to "recruit out-of-state companies to expand their operations in Arizona."[38] Indeed, members of the Retail Competition Advocates and RESA are already bringing new business to Arizona. Direct Energy has two call centers in Arizona, one in Tuscon and a new one in Tempe, that together employee over 1000 people, and owns several Arizona franchise businesses, including Benjamin Franklin, Mr. Sparky, and One Hour Heating and Cooling, that bring its total employee count to nearly 1500. Constellation has worked with nine separate Arizona school districts to deploy over 11 MW of solar generation, with an additional 18 MW in construction.

APS's contention that retail choice will cause Arizona's energy future to be dictated by outside forces that Arizona cannot control or influence is somewhat silly on its face. First, APS, would be free, should it elect to do so through a competitive affiliate, to compete to serve Arizona's retail load. APS could bring its skill and brand to bear

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[37] See page 2 of APS cover letter to its opening comments.

[38] See Information about the Arizona Commerce Authority at: http://www.azcommerce.com/

through competitive offerings and best practices. APS could even choose through a competitive affiliate, to compete in the service territories of the other Arizona utilities – nothing wrong with that, and indeed all the better.[39]

APS seems to conveniently forget that retail providers will be licensed by the Commission, whether they are headquartered in Arizona or elsewhere. The Commission is a professional regulatory body and already regulates entities that operate in Arizona but are organized under the laws of other jurisdictions. Indeed, the Commission is the constitutional body in Arizona to whom voters in Arizona have entrusted the job of authorizing non-Arizona corporations to do business in the state

As for the general idea that utility regulators are in "control" of the energy future under traditional monopoly, the obvious reality is that vertically-integrated monopolies present utility regulators with a *fait accompli* circumstance that, in practice, allows for only fairly minor adjustment and limited degrees of freedom with which regulators can exercise judgment. External conditions such as fuel and labor prices, costs of capital, demand in the economy for electricity and costs of capital assets are all well beyond the control of regulators and largely beyond the control of utility management. By contrast, regulators in a competitive model are in a position to fashion, monitor and enforce "rules of the game" that provide the boundaries within which competitors and consumers interact, approve fees and the rules for the use of monopoly services such as delivery and influence operations. Regulators in more than a dozen states with broad-based customer choice are actively and proactively engaged in guiding the development of those markets, and customers are benefitting every day.

4. The process and legal issues identifed in the *Phelps Dodge* decision are easily avoided or resolved through Commission process; no constitutional amendments are necessary.

In their July 15 comments, RESA and Retail Competition Advocates explained why the Arizona constitution does not deprive the Commission of the ability to proceed with retail competition. The Commission solicited input on that issue in light of *Phelps Dodge Corp. v. Ariz. Elec. Power Coop.*, 207 Ariz. 95, 83 P.3d 573 (App. 2004) (*"Phelps Dodge"). Phelps Dodge* invalidated certain provisions of the Commission's 1996 Retail Competition Rules. Even assuming *Phelps Dodge* remains good law and the Commission should feel constrained in perpetuity by the ruling of a single court of appeals, the issues raised by the decision are readily surmountable. Indeed, in its August 12, 20010 staff report in Consolidated Docket Nos. E-00000A-02-0051 and E-00000A-01-0630, Commission staff noted that establishing retail competition in Arizona would need to factor in *Phelps Dodge,* but made no suggestion that the decision required the effort to be abandoned entirely.

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[39] It is also interesting to note that APS has stated that the $500 million in state and local taxes that it pays in Arizona may go to companies in other states if retail competition is allowed. It is important to realize the taxes that APS remits are collected from ratepayers. As such, while they may well have a large tax liability in Arizona, they collect all of these taxes from their ratepayers. In short, APS is a huge tax collector in Arizona, but it is wholly disingenuous and misleading for them to suggest that their shareholders pay any taxes at all. be

1. **Under *Phelps Dodge*, the Commission's rate making duties can be satisfied by setting a broad range of rates within which a competitive marketplace can operate.**

Opponents of deregulation argue that the Commission's mandate to ensure "fair value" ratemaking is inherently antithetical to the concept of rates established by a competitive market. However, the *Phelps Dodge* decision does not stand for the proposition that the Commission may not lawfully approve rates and charges for legally certificated ESPs in connection with the provision of competitive retail electric service. Rather, *Phelps Dodge* merely held that, in approving rates and charges for the ESPs that were concurrently being certificated, the Commission had failed to satisfy certain requirements under Article 15, Sections 3 and 14 of the Arizona Constitution, incident to an exercise of the Commission's ratemaking powers. Rather the Court affirmatively stated that "nothing in the plain language of Article 15, Section 3 requires the Commission to prescribe a single rate rather than a range of rates. (*Phelps Dodge,* 207 Ariz. 95, 109). In their Comments, the Retail Competition Advocates pointed out language from the *Phelps Dodge* decision itself that could be used as guidance for determining and using "fair value" and establishing "just and reasonable" rates for ESP's. (*See* Retail Competition Advocates Comments, pp. 35-36.).

In addition, some opponents have questioned whether a valid range of "just and reasonable" rates could be established based on the content of currently pending ESP CC&N Applications. As set forth in the CC&N Applications filed by Constellation NewEnergy Inc., Direct Energy Services, LLC; and others, the proposed ESP prices would be calculated within a range of rates not less than the ESP's marginal cost and a "Not to Exceed Price" determined by either a specific index or generation rate at the time the contract was entered into, plus 35%. In that regard, these ESPs intend to satisfy the "just and reasonable" requirement for establishing such rates by putting on the record at hearing evidence of their respective marginal costs, as well as examples of indices and generation costs used to calculate rates within the context of a given tariff.[40]

In that regard, there is no meaningful constitutional difference between the process for establishing a range of rates as described above for ESPs, and the process for determining "just and reasonable" rates in a rate case for incumbent electric utilities. In a rate case for the latter, a test year represents a snap shot of revenues and expenses at a specific point in time that may or may not be reflective of the utility's actual circumstances when rates based on test year data actually go into effect. Yet, the utility will assert that rates established in reliance on that test year snap shot picture are just and reasonable. So, too, are rates for an ESP when based on evidence of the aforementioned nature, as presented at hearing by an ESP CC&N Applicant which discloses a snap shot picture of the data upon which its proposed range of rates is based.

[40] In addition, at such hearings, evidence will be presented to enable the Commission to make that "fair value" finding required by Article 15, Section 14 of the Arizona Constitution.

Further, a sliding scale of charges is permissible under Arizona law as long as such rates are approved by the Commission. Specifically, A.R.S. 40-368 states as follows:

A. Any person engaged in the production, generation, transmission or. . . . may establish a sliding scale of charges . . . A schedule showing the scale of charges under such an arrangement shall first be filed with the Commission and the schedule and each rate[or range of rates] set out therein approved by it.

Finally, Commission approval of a range of rate methodology took place in the approval process of APS's Rate Schedule AG-1, which allows qualified APS customers to directly negotiate and contract with third party providers from the competitive market place for the price to be paid for power to be purchased from such third party providers and delivered by APS pursuant to Rate Schedule AG-1. (See Decision No. 73183 (May 2012)

2. Allowing retail competition would not run afoul of the prohibition against discriminatory pricing.

Opponents of deregulation argue that under Article 15, Section 12 there shall be "no discrimination in charges...for rendering a like and contemporaneous service." Opponents also argue that under A.R.S. § 40-334, "a public service corporation shall not, as to rates, charges...make or grant any preference or advantage...or establish any unreasonable differences as to rates, charges...or in any other respect...between classes of service."

In *Phelps Dodge*, the Cooperatives made similar discrimination arguments and those arguments were rejected by the Court of Appeals. First, the Cooperatives argued that the Commission's decisions to award CC&N's to ESP's unlawfully differentiated among public service corporations by allowing ESP's to negotiate rates within multiple service territories, while Affected Utilities were confined to geographically defined territories and could only charge specific rates prescribed by the Commission (*Phelps Dodge,* 207 Ariz. 95, 118.). In rejecting this argument the court stated:

Nothing in the language of Article 15, Sections 2 and 3 limits the Commission's authority to differentiate among public service corporations in a manner in which they serve the public interest.. . . Thus as long as the Commission's differentiation among public service corporations is reasonably related to the Commission's rate making authority, . . . Sections 2 and 3 do not prohibit such distinctions.

(Id.)

In *Phelps Dodge*, the Cooperatives also argued that the Commission's decisions which would permit the ESP's to charge different rates to allegedly similarly situated customers would violate Article 15, Section 12 of the Arizona Constitution and A.R.S. 40-334. (*Id.*) In response, and in rejecting that line of argument, the court stated that:

> *"ESP's remain bound by Article 15, Section 12 and A.R.S 40-334 in negotiating and establishing rates with customers. . . Until an ESP charges a rate that allegedly violates these provisions, allowing the court to apply legal principles to a concrete set of facts, the issue is not ready for review.* ***Additionally, unless such pricing abuses occur, the Cooperatives will not suffer any direct and immediate impact from a competitive scheme that permits ESP's to negotiate rates with customers.*** *(Emphasis added).*

(*Phelps Dodge,* 207 Ariz. 95, 119.).

3. Opponents' arguments regarding alleged RTO and ISO impediments lack merit.

As described in the July 15, 2013 Comments of Retail Competition Advocates and RESA, interim developments in the electric utility industry in Arizona pertaining to the Arizona Independent Scheduling Administrator ("AISA") and a related Commission decision, suggest that *Phelps Dodge* does not preclude AISA from continuing to perform an important role in relation to retail electric competition. [See Retail Competition Advocates and RESA Comments p. 34, *citing* Decision No. 68485, page 15, lines 5-11].

In addition, the Retail Competition Advocates and RESA pointed out that although they do not believe that membership in an RTO or ISO is essential for the resumption of retail electric choice in Arizona, the option does exist for the incumbent utilities to formally join or form a FERC-regulated RTO or ISO, and that the benefits of membership would include a more efficient dispatching of power across a broader geographic footprint with resulting significant benefits to Arizona's electric customers as a whole. [See Retail Competition Advocates Comments, p. 26].

In that regard, the July 15, 2013 Comments of Freeport McMoRan Copper & Gold, Inc. and Arizonans for Electric Choice and Competition also contain an excellent discussion on why a FERC regulated RTO or ISO is neither a legal nor functional prerequisite to the resumption of retail electric competition in Arizona. (See Freeport McMoRan/AECC Comments at p. 6-7, 11-12 and 17-18).

4. A.R.S. § 40-367 does not make retail competition unworkable.

Opponents to competition also argue that A.R.S. 40-367(B), which requires notice of filing of new schedules, would be unworkable in a competitive market because ESPs would be unwilling to make "competitively confidential" rates open to public inspection. First, A.R.S. 40-367 references "schedules," which the Retail Competition Advocates and RESA interpret as tariffs. In that regard, it is contemplated that certificated ESPs would be obligated to publish tariffs that set forth a Commission-approved "range of rates" calculated at a level not less than the ESP's marginal cost and not more than its "Not to Exceed Price," plus 35%, as described above.

Second, the Retail Competition Advocates and RESA definition and filing of "schedules" under A.R.S. 40-367(B) contemplates the disclosure of information to the

Commission on a confidential basis that the ESP's would deem to be "competitively sensitive" in nature. The Commission has previously made special consideration for such instances when dealing with special contracts containing such information. Such contracts are submitted to the Commission Staff for review and analysis, and the special rates or pricing provisions contained therein are approved by the Commission if found to be "just and reasonable", but such pricing provisions are not open to public inspection. The Retail Competition Advocates and RESA believe a similar procedure could be used to confirm whether an ESP's contract pricing provisions were within "the range of rates" of its then existing Commission-approved tariffs.

5. Electric competition does not violate the equal protection provisions of the Fourteenth Amendment.

Although not supported by fact or law, opponents of competition assert that the current rules violate the equal protection provisions of the 14^{th} Amendment to the United States Constitution and Article II, Section 13 of the Arizona Constitution in that they do not provide equal treatment of all electric utilities and electric service providers. This line of argument was carefully analyzed and rejected as lacking merit by the Court of Appeals in the *Phelps Dodge* decision. (*Phelps Dodge,* 207 Ariz. 95, 123-124).

6. Phelps Dodge does not make it impossible to separate monopoly and competitive services.

Although *Phelps Dodge* ruled that the Commission did not have the authority to require Affected Utilities to divest generation assets, the court did find that the intended separation of monopoly and competitive services could still be achieved through Affected Utilities' compliance with R14-2-1615(B), which prohibits them from competing and was not challenged in the case. More specifically, the court stated:

> *If the Affected Utilities choose to retain competitive assets for a period beyond the prescribed date, or indefinitely, the competitive market is seemingly unaffected, as long as the Affected Utilities abide by R14-2-1615(B), which prohibits them from competing.*

[Phelps Dodge 207 Ariz. 95 at p. 114]. As a result, there is no legal or functional need to require divestiture **as long as** the Affected Utilities comply with R14-2-1615(B). (Emphasis added).

7. The Phelps Dodge decision does not impose any unavoidable legal constraints or prohibitions to the resumption of retail electric competition.

In its July 15, 2013 Comments, the Arizona Center for Law in the Public Interest ("Center") stated as follows:

> *"Once the Corporation Commission has complied with its Constitutional duties to find fair value and establish just and reasonable rates, it might*

be difficult to describe what's left as competition. Given the significant legal constraints imposed on establishing retail electric competition, the proper analysis is whether the benefits from the limited competition allowed by the Constitution outweigh the significant costs to consumers that may be generated if competition is established."

It is incorrect for the Center to suggest that obsserving *Phelps Dodge* would leave the Commission without a meaningful role for competition within the electric industry in Arizona.

As discussed in the Retail Competition Advocates and RESA July 15, 2013 Comments and these reply Comments, the *Phelps Dodge* decision does not impose any unavoidable legal constraints or prohibitions to the resumption of meaningful and effective retail electric competition at this time. More specifically, the Commission can adopt retail competition without relying upon the disputed provisions at issue in *Phelps Dodge*. The Commission can likewise readily make the required findings as to "fair value" and what constitutes "just and reasonable" rates for an ESP in an evidentiary hearing. To the extent certain rules were found invalid under *Phelps Dodge* merely because they were not submitted to the Arizona Attorney General for review and certification pursuant to the Arizona Administrative Procedure Act that is a situation which is easily corrected.

5. Neither retail electric competition nor the resulting design of utility POLR service (or any default service design) creates reliability risks for the Arizona electricity grid; such claims are pure fiction.

Transmission and Distribution: Commenters who oppose retail electric competion in Arizona claim – without any viable evidence –that the resumption of retail choice in Arizona can only be accomplished if the Arizona utilities join a Regional Transmission Organization ("RTO"). For instance, APS says: "the establishment of an RTO is a prerequisite to the introduction of full retail electric restructuring in Arizona",[41] that "there is no promising RTO solution for Arizona",[42] and that the "AZISA was meant to act as an interim organization that would begin to assume some of the functions of a RTO."[43] In short, APS (i) says that only an RTO will work, (ii) makes it clear that they have no interest or willingness to bring RTO like efficiencies to the market place, (iii) contends that the Commission has no authority to require them to join an RTO, (iv) hints that it would fight any move toward RTO membership, and (v) says that the very organization (AZISA) that was intended to provide these functions in the absence of an RTO, is incapable of doing so, even though it has been charging its ratepayers all these years to keep the organization in existence up to this very day.

[41] See page 20 of 35 of APS Exhibit A: APS Response to Staff Electric Restructuring Questions.
[42] See Page 17 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring
[43] See page 17 of 21 of APS's Initial Response to Commision's inquiry Regarding Electric Restructuring

Whether membership in an RTO is ultimately in the best interest of Arizona customers is not an issue that needs to be decided in order to move forward with the resumption of retail electric choice. There are three reasons why this is the case.

First, successful retail competition requires competitive wholesale markets, which already exist through the Western Electric Coordinating Council ("WECC"), the entity that establishes and enforces reliability standards for the bulk energy system throughout the west. Even without an RTO, Arizona utilities are still part of WECC, and therefore a competitive retail market will have access to competitive wholesale markets. If the Arizona utilities joined an existing RTO, wholesale pricing could be even more transparent, but having an RTO is not necessary.

Second, under retail electric competition, transmission will not be deregulated and the Arizona utilities will continue to be able to recover prudent transmission-related investments needed to maintain reliability.

Third, the first phase of the AZISA protocols has already been approved by FERC and is ready and workable. Moreover, as AZISA notes in its opening comments:

> AZISA has and is intended to perform critical functions to support the delivery of power over the interconnected transmission and distribution systems in Arizona to retail consumers, consistent with open access requirements. The AZISA is ready to ramp up its efforts to perform its functions, including updating its Protocols to allocate transmission fairly and reflect current WECC practices for scheduling, delivering and settling power.[44]

The utilities' opening comments also suggest that a move to retail electric competition will compromise the financial health of the incumbents, pointing particularly to recent ratings downgrade for TEP that cited the uncertainties about implementation of retail choice as the reason for the downgrade. Correctly, the Commission has already responded to this by making it clear they intend to act quickly to resolve through this proceeding the open question as to whether Arizona will resume retail choice. The Commission should also take comfort in the fact that the implementation of retail choice in other jurisdictions has created no lasting detrimental impact to the incumbent utilities who continue to own and operate the transmission and distribution systems. Indeed, a review of data from S&P shows that utility credit ratings appear to be driven by factors such as regulatory environment, political influence and financial stability and not related to whether competitive retail choice exists in a state.

S&P provides a periodic assessment of the regulatory climate of electric and gas utilities. This assessment is part of their credit rating process and is intended to categorize whether the state in which the utility resides is one in which there is an overall framework that is more or less supportive of strong credit ratings for its utilities. The assessment that S&P performs of the states overall credit support climate is based on quantitative and

[44] See page 6 of AZISA opening comments.

qualitative factors, focusing on four main categories: the basic regulatory paradigm employed in the jurisdiction, ratemaking procedures, political influence, and financial stability.[45] Based on this analysis, S&P categorizes each state (except for Tennessee, Alaska, and Nebraska) and the District of Columbia into one of the five following categories: 1) most credit supportive; 2) more credit supportive; 3) credit supportive; 4) less credit supportive; and, 5) least credit supportive. A state in the category of "most credit supportive" means that S&P's assessment has found that state to have policies that are intended to support strong credit ratings for its utilities.

Each of the states that S&P has categorized have been further categorized as to whether or not they have functioning competitive retail choice markets, or whether they are traditionally regulated. Then the average S&P credit ratings of the gas and electric utilities in grouping of states have been calculated. Table 1 below shows the average credit rating of the gas electric utilities in each of the categories.

Table 1

Mode	Regulatory Jurisdiction: More Credit Supportive	Regulatory Jurisdiction: Less Credit Supportive
Competitive	BBB average rating 5 states States: MA, NH, NJ, OH, PA	BBB+ average rating 9 states States: CT, IL, ME, MD, NY, RI, TX, DE, DC
Traditional	BBB+ average rating 23 states States: AL, CA, GA, IA, MI, SC, WI, AR, CO, FL, ID, IN, KS, KY, LA, MN, NV, NC, ND, OK, OR, SD, VA	BBB average rating 11 states States: AZ, HI, MS, MO, MT, UT, VT, WA, WV, WY, NM

Source: S&P

1) *Analysis excludes Tennessee, Alaska, and Nebraska*
2) *More Credit Supportive category includes Most Credit Supportive, More Credit Supportive, and Credit Supportive*
3) *Less Credit Supportive includes Less Credit Supportive and Least Credit Supportive*

Among the "More Credit Supportive" jurisdictions, the utilities operating in traditional states have seen a narrow credit advantage compared to utilities operating in competitive states, while among the Less Credit Supportive jurisdictions the utilities

[45] The assessment process used by S&P is described in detail in the following documents, which are available through subscription: Standard and Poor's Global Credit Portal Rating Direct, November 7, 2007 and Standard and Poor's Ratings Direct, December 28, 2012

operating in competitive states have seen a narrow credit advantage. This refutes any notion that customer choice is a determinative factor in a utility's credit rating; indeed the most important factor is the extent to which the state creates an overall favorable environment for strong credit ratings. Thus, the Arizona Commission in making it clear that it is going to act promptly and decisively to determine the future of retail choice in Arizona is precisely the right move.

Finally, APS also contends that reliablity will be threatened because the Commission will be forced to relinquish existing jurisdiction to FERC. These inaccurate and unsupported claims of APS and others are thoroughly debunked in Section 3 of these comments. Moreover, there are more than 65 investor-owned utilities throughout the 17 states that allow retail choice.[46] While opponents try to suggest that retail choice creates the potential for a less reliable grid, the fact is that they can point to no report from a state or federal regulator, NERC, the regional transmission organizations, or other expert or independent body that attributes any delivery reliability issue to the fact that the state allows retail electric competition.

Generation Supply Reliablity: With respect to reliablity of the supply base in Arizona, and claims that supply reliability will be degraded under retail choice, such claims are equally unfounded.

Of particular note are the comments of APS and several other opponents of retail choice that point to ongoing deliberations in Texas about the need for a wholesale capacity market to ensure the availability of the right amount of generation supply, and their claims that these deliberations are proof that reliablity in retail competition states is compromised. These arguments have no merit. The wholesale market design modifications under discussion in Texas are not required because of retail competition in

[46] In California: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Pacific Power; In Connecticut: Connecticut Light & Power Co, United Illuminating Company, Delmarva Power; In Illinois: Ameren, Commonwealth Edison, MidAmerican; In Massachusetts: National Grid, NSTAR, Western Massachusetts Electric Company; In Maryland: Baltimore Gas & Electric, Delmarva Power & Light Co., Potomac Edison, Pepco; In Maine: Central Maine Power Bangor Hydro-electric company, Maine Public Service Company; In Michigan: Alpena Power Co., Northern States Power, Wisconsin Electric Company, Indiana Michigan Power, Consumer Energy, Detroit Edison Company, Upper Peninsula Power Co: In Montanan: Northwestern Energy, MDU Resources Group, Inc.; In New Hampshire: Granite State Electric Co, Public Service Co. of New Hampshire, Unitil Energy Systems, Inc.; In New Jersey: Atlantic City Electric Co., Jersey Central Power & Light Co., Public Service Electric & Gas Co., Rockland Electric Co.; In New York: Central Hudson Gas & Electric Corp, Consolidated Edison Co. of New York, Inc., New York State Electric & Gas Corp, Niagara Mohawk Power Corp, Orange & Rockland Utilities, Inc., Pennsylvania Electric Co., Rochester Gas & Electric Corp.; In Ohio: Cleveland Electric Illuminating Co., Columbus Southern Power Co., Dayton Power & Light Co., Duke Energy Ohio, Inc., Ohio Edison Co., Ohio Power Co., Toledo Edison Co.; In Pennsylvania: Citizens Electric Co., Duquesne Light Co., Metropolitan Edison Co., PECO Energy Co., Pennsylvania Electric Co.; In Rhode Island, Block Island Power Co., Narragansett Electric Co.; in Texas: AEP Texas Central Co., AEP Texas North Co., CenterPoint Energy Houston Electric, LLC, El Paso Electric Co., Entergy Texas, Inc., Oncor Electric Delivery Co. LLC, Southwestern Electric Power Co., Southwestern Public Service Co; In the District of Columbia: PHI

that state, as noted by the Texas Public Policy Foundation.[47] In fact, that very market attracted over $25 billion generation investment for the construction of 39,000 MW of new capacity.

Since 2009, the Texas competitive market, which is not interconnected to other systems, has been growing into a large overhang of generating capacity. Now, in recognition of the significant economic and population growth in Texas and the need for and the expansion of intermittent renewable resources in need of back-up generation, Texas has undertaken a serious review of its unique "energy-only" wholesale market.

Texas has, so far, successfully relied on energy-only pricing. Policymakers and regulators and other market participants and stakeholders are considering whether the energy-only model provides sufficient market price signals for further investment. One option under serious consideration is the adoption of capacity markets, akin to that which has been operating with success in PJM. These deliberations are healthy, and necessary. No one who is directly involved in the deliberations has suggested that Texas should plot a path back toward monopoly and traditional regulation. The opponents of retail choice in Arizona are grasping at straws.

It must also be noted that APS seems, inexplicably, to misconstrue some rather simple facts when it says: "For the second year in a row, Texas faces the prospects of blackouts since adequate generation is no longer being built in spite of dramatically rising electricity prices."[48] To support this statement, APS points to a Reuters news article reporting the Texas Commission's decision to increase the energy-only pricing bid cap in Texas from $3000 to $5000. While this increase in the bid cap is a 66% increase in the cap, there is, of course, no such increase in prices paid for electricity in Texas. In fact, since the capacity market discussions began in Texas, retail prices have remained stable.

Moreover, the outlook for dire consequences in Texas appears to be wholly overstated. A recent press release from ERCOT notes that during the region's third highest demand in history that occurred on August 7, 2013, "the grid experienced no problmes during the day, with more than 74,000 MW of electricity, including more than 2,300 MW of wind power available during the peak hour."[49]

Finally, the opponents of retail choice argue that replacing integrated resources planning with competition would render the Commission unable to impose reliability

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[47] See Attachment 5: Texas Public Policy Foundation report: Prices Reliability, and Consumer Choice in the Texas Electricity Market, dated January 22, 2010 which states: "Texas, alone among the states, has moved forward into a truly restructured and competitive electricity era, which has brought lower prices, greater reliability, and increased consumer choice." The full report can be found at , http://www.texaspolicy.com/center/economic-freedom/reports/prices-reliability-and-consumer-choice-texas-electricity-market

[48] See page 3 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring
[49] See Attachment 15 which can be found at the following link: http://www.ercot.com/news/press_releases/show/26528

standards on retail suppliers who serve load in Arizona. This is completely unfounded. In all restructured states, state regulatory agencies are responsible for establishing planning reserve margins[50] that must be met by their load serving entities, and for enforcing compliance with those requirements.[51][52] State regulatory bodies are also able to impose and enforce a number of requirements including, but not limited to rules regarding renewable and/or greenhouse gas emission standards.

POLR Service: Several commenters suggest that divestiture of the utilities of their generating assets, along with a requirement that they continue to be the Provider of Last Resort (POLR) provider, will also contribute to an unreliable supply framework in Arizona.[53] APS states:

> Utilities in restructured markets that have divested their generation often continue to have responsibility for acquiring supplies for a large portion of their total load, including virtually all of their residential customers and many smaller C&I customers that receive POLR service. If utilities are no longer allowed to own or build generation, or even to enter into long-term power purchase agreements, then they must depend on short-term purchases from the wholesale market. Utilities generally conduct auctions each year for a portion of their portfolio *(e.g.,* one-third) and then enter into power purchase agreements with the winning bidders. These POLR customers are completely exposed to the short-term wholesale market and cannot take advantage of longer-term generation or contractual hedges that are a fundamental element of any utility resource portfolio. Further, if the retail restructuring model allows customers to switch back and forth between a POLR service and an alternative provider, this creates

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[50] As an example, see Attachment 16; "Results of the NYSRC technical study show that the required NYCA IRM for the 2012 Capability Year is 16.1% under base case conditions." New York Control Area Installed Capacity Requirements For the Period May 2012 through April 2013, New York State Reliability Council, LLC Installed Capacity Subcommittee. Pg 3, http://www.nysrc.org/pdf/MeetingMaterial/ECMeetingMaterial/ECAgenda151/2012%20IRM%20Draft%20Report%2011-6-11.pdf

[51] PJM RPM Base Residual Auction Report that shows 21% reserve margin for 2016/17 (Page 6): http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

[52] "New York State has a maximum of 43,686 megawatts of available resources tomeet an anticipated 2012 summer peak demand of 33,295 megawatts..., " New York State ISO 2012 State of the Grid Report, pg 9, found at the following link: http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/power_trends_2012_final.pdf

[53] Retail Competiton Advocates and RESA note that as a fundamental matter, the best practice here is for the utilities to be relieved of all supply obligations and remaint as a fully regulated transmission and distribution company.

> reliability concerns and results in yet higher costs for all POLR customers.[54]

APS correctly describes some POLR designs in terms of the utilities entering into wholesale power purchase agreements to meet their POLR load serving obligations. APS's statement, however, that those customers "cannot take advantage of longer-term generator or contractual hedges that are a fundamental element of any utility resource portfolio" is nothing more than a wholly inaccurate scare tactic. Retail choice gives customers who choose a supplier precisely that ability – to determine what level of hedging and other terms and conditions they want. Moreover, with respect to the ability for customers to move to and from POLR service, there is no evidence whatsoever that supports the APS statement that this raises costs for all POLR customers. While there are several different POLR models, all contain features that address the very issues APS raises:

- A common feature of many of the models is that the winning bidders take on the obligation to meet a percentage of the utilty POLR load; if that overall POLR load increases because customers return to utility service, the amount of energy the supplier must provide goes up – at the same fixed price that was the suppliers' winning bid. Likewise if the amount of POLR load decreases because customers leave for retail choice, the amount of energy the supplier must provide goes down.

- Some of the models do provide that returning customers must remain on POLR service for a set period of time to minimize any cost shifting.

- Some of the models provide that returning customers will pay a market-based price for some period of time before they can take service under their otherwise applicable tariff.

The main point here is that POLR service can be designed to provide reasonably priced energy supply to customers who do not choose an alternative competitive supplier, without any impact on reliability. Customers can make longer term or shorter term procurement decisions, and find customized energy management in the competitive retail market, where they can manage the pricing and market risks of those choices.

Then, APS goes on to say:

> The Commission's current role in energy policy would change dramatically with the restructuring of the Arizona market and potential adoption of divestiture of utility generation assets. In short, the Commission's role with respect to future supply would be restricted to the design and implementation of the POLR contracting process. The prices that will be paid by POLR customers will be determined by wholesale market operations, rules, and market conditions.[55]

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[54] See Page 6 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring
[55] See page 8 of 21 of APS Initial Response to Commision's inquiry Regarding Electric Restructuring

These reply comments address jurisdictional issues in detail in Section 3 below, but APS's statements about dramatic changes in the Commission's role in energy policy if utilities meet their load obligations through POLR deserve a response here in the context of reliability issues. First, APS seems to suggest that having POLR or default energy pricing be reflective of wholesale market conditions is a bad thing. It is not. In fact, it is the best way to empower customers to make economically efficient choices about their energy use. That is why one of the most important features of retail choice market design involves careful attention to how the utilties procure power at wholesale to meet their ongoing load obligation, if indeed they retain any load serving obligation at all, and issue that must be carefully considered in Phase 2 of this proceeding. All jurisdictions that have vibrant retail choice models recognize this, and the fact is that carefully designed POLR service is one of the most important feature to ensuring the implementation of competitive wholesale and retail market structures. Having the utilities look to the competitive wholesale markets for their POLR supply, to the extent they provide POLR service, through auctions ensures that they do not retain an unfair competitive advantage over competitive suppliers through rate–regulated ownership and control of supply-side resources. Indeed, it is this commitment of policymakers to competition – at both the wholesale and retail level – that will determine the success of retail choice. APS's suggestion and characterization that POLR design is a trivial matter is, therefore, way off the mark. Importantly, regulators in the restructured jurisdictions of New Jersey, Maryland, Pennsylvania, New York , Ohio, Illinois, Massachusetts, Connecticut, Rhode Island, New Hampshire, Delaware, and District of Columbia have been continuously approving some degree of market reflective default pricing since the inception of retail competition in these various states that dates back more than a decade ago.

APS makes assertions about price volatility for residential customers it then fails to support with any data or empirical reference. [56] The real issue here is whether competitive retail choice models are, in their operation, prone to price volatility that distinguishes such models from traditional regulatory regimes. First, the assertion of volatility as characteristic of retail choice seems designed to convey the idea that because hourly price may fluctuate considerably during the day and across seasons, end-user price must also fluctuate accordingly. This ignores the fact that customes can, and many do, choose fixed price contracts. Some, by their own hand, choose daily or hourly pricing. Second, the data do not support an assertion that pricing to residential customers inherently becomes more volatile under retail choice. Specifically, if one measures volatility by calculating relative standard deviations of annual residential delivered prices for each state over various periods and also calculates average relative standard deviations, the assertion does not hold water. Third, measuring volatility in the context of reviewing overall price changes that have occurred further debunks the assertion that pricing become more volatile for residential customers under retail choice.

The analysis to refute the APS assertions is as follows. A total of all fifty states and the District of Columibia were broken into three categories. The first group, which

[56] See Page 7 of 35 of APS Exhibit A: APS Response to Staff Electric Restructuring Questions

includes 14 states and the District of Columbia, are all states that have substantial retail competition. The second group of thirty-two states are all traditionally regulated. The third group includes Arizona, California and Michigan which are hybrids of retail choice and traditional regulation. Next, the relative standard deviation in annual delivered prices and the overall price changes for each category were calculated for three relevant time periods. One period is the decade of 1993 through 2002 prior to the large scale implementation of customer choice. Another period is 2003 through 2012, during which competitive pricing has been in widespread operation. The third is 2008 through 2012, the recent period of national economic stress. Table 2 below shows the relative standard deviation in annual delivered prices for each group in each time period. Table 3 shows the average residential price change for each group in each time period. There are four notable conclusions:

- The two bookend periods of 1993-2002 and 2003-2012 show similar standard deviations in annual delivered prices for the three groups, indicating that there was no material change in the level of price volatility before the full implementation of choice and after choice has been in operation for a considerable period.
- During the period of 2003-2012, all three groups show higher volatility than was the case during the 1993-2002 and the 2008-2012 time period. While the competitive group showed slightly higher volatility relative to the traditional and hybrid groups in this period, the competitive group had a lower rate of overall change in price.
- The competitive group had lower overall residential changes in price in all three time periods as compared to the traditional and hybrid groups.
- Taken all together, this analysis demonstrates that volatility is not a function of whether there is retail choice or not, but rather is function of broader industry and economic conditions that affect prices.

Table 2 Average Residential Relative Standard Deviation by Group by Time Period

	1993-2002	2003-2012	2008-2012
Competitive	4%	14%	4%
Traditional	4%	11%	6%
Hybrid	4%	12%	5%

Source: U.S. Energy Information Administration analysis

Table 3 Average Residential Price Change by Group by Time Period

	1993-2002	2003-2012	2008-2012
Competitive	-2%	39%	-4%
Traditional	8%	40%	14%
Hybrid	5%	42%	16%

Source: U.S. Energy Information Administration analysis

The assertions made by APS about price volatility being a feature of customer choice are without merit and should be regarded by the Commission for what they are –

rhetorical assertions intended to alarm and obfuscate, rather than provide any useful information to the discussion of the pros and cons of retail choice. Furthermore, as shown in the tables above, residential customers in competitive states have benefited from lower overall price changes over the past 20 years relative to the two other groups. This benefit has been more pronounced in the past 5 years during a time of economic stress.

In order to provide the Commission with full transparency into the analysis presented here, Attachment 18 to these Reply Comments provide the relative standard deviation and residential price change rankings of each state for the three time periods.

Indeed, APS's example of the 72% price increase that occurred in Baltimore Gas & Electric ("BG&E") service territory conveniently omits important facts. The long-term price caps that were ending at that time were a function of rate freeze that was initiated in the year 2000, and was initiated with roll-back of then effective rates, which had been in place since 1993, by 6.5%. Rather than providing for a procurement process that would take place over a longer period or one that could be adjusted to fit market conditions, BG&E was required to undertake an auction at a specific point in time. The time coincided with the immediate aftermath of hurricanes Katrina and Rita, when energy prices escalated dramatically due to damage to natural gas supplies in the Gulf of Mexico. In addition, customers could shop for competitive alternatives to the POLR rate. It is not surprising that, having capped residential rates for six years, prices rose signficiantly from levels below those in 1993, especially in light of the fact that they were uncapped at a time when natural gas prices were at their peak (and have since subsequently fallen dramatically.

Rate freezes have been amply demonstrated to lead to difficulty and political angst when they roll off, as they always must. Although price caps may seem to benefit consumers in the short run, they can irreparably harm competition in the long run and, as a result, inflict greater overall economic harm on the very consumers the price caps are supposed to benefit. Capping retail prices below market eliminates retail competition, destroying customers' access to the individual flexibility in prices, service terms, and bundled services that electric restructuring was designed to unleash. Moreover, it restricts new generation investment, and raises the cost of investment because of the additional regulatory uncertainty price caps create.[57]

The economic damage caused by the price rollback and multi-year price caps were self-imposed by the Maryland legislature. The adverse impacts can be completely avoided in Arizona. Procurement strategies and methods for POLR supplies have been improved across all customer choice states and continue to advance to ensure customers benefit from retail competition.

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[57] These points were made clear in testimony of Jonathan Lesser before the Maryland Public Service Commission in Proceeding 9063, which can be found at the following link: http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9000-9099\9063\Item_94\\JALTestimony906310_3_06(Final).pdf

Reliability of competitive suppliers versus utility supplier: Another aspect of POLR service that APS raises is the potential for customers on retail service to be turned back to POLR service with no warning, either because the supplier is defaulting on its contractual obligations, or voluntarily. These are indeed representative of difficult situations, but do not represent a valid reason to avoid retail competition. Furthermore, these instances are certainly the exception rather than the norm.A feature of all retail competitive markets is the presence of POLR service, for precisely this purpose – to ensure that a supplier's failure to deliver does not result in a situation where a customer is without power. Rules are established that determine when and in what circumstances customers receive POLR service. It should be noted that in all the markets that use the POLR auction approach, there has not been, to the knowledge of the Retail Competition Advocates or RESA, one single incident in which the wholesale supplier has defaulted on its obligations.

6. **Retail competition does not create stranded costs but merely reveals the above market prices being paid by customers due to uneconomic investment and operating expenses associated with monopoly service.**

In its initial comments, AARP asserts that APS and TEP were already granted \$350 million and \$450 million respectively in stranded cost recovery, even though Arizona's earlier entry into retail choice was terminated, and asks whether "the incumbent utilities [will] claim that retail competition results in stranded costs and how much would any stranded cost recovery, if allowed, add to consumers' bills?[58] With this question, AARP seems to suggest that stranded costs are created by retail competition. They are not. Stranded costs occur when utility procurement decisions become uneconomic when compared to other alternatives. Utility customers pay stranded costs all the time, and it is likely that Arizona's utlity ratepayers are paying some in their current bundled monopoly rates. Thus, while retail competition most certainly does not create stranded costs, it does create a need to address them, whch every jurisdiction that has implemented electricity customer choice has done. These costs are a function of traditional monopoly investment and operating expenses that happen to be above market and are revealed to be such by the opportunity for customers to seek better priced alternatives. This is an important issue in the transition to retail choice, and is certainly one that Arizona will need to deal with. However, the first step in coping with any problem is to be honest about its cause and actual magnitude.

Several sets of opening comments make statements that the costs associated with stranded utility investments are a reason to not resume retail chioce. For instance, APS states that both conventional and renewable investments it has made no longer would be used and useful under retail competition, but that the above market costs of those investment will still need to be recovered, and that the current outlook for low power prices may make their current stranded costs higher than they were the first time APS was allowed such recovery.[59]

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[58] See page 5 of AARP's opening comments

[59] See page 13 of 35 of APS Exhibit A: APS Response to Staff Electric Restructuring Questions

SRP refers to stranded costs as a start up cost associated with retail choice implementation and says that they will be in the "billions" because of investment in coal and natural gas fired generation that the utilities have along with solar, wind and geothermal assets and other environmental upgrades.[60]

Like AARP's comments, the APS and SRP comments demonstrate a complete misunderstanding of what stranded costs are. Again, stranded costs do not exist because there is retail choice; they exist when utilities make investments that prove to be uneconomic. In fact, their stranded cost comments make a persuasive case for retail competition.

In a vertically integrated monopoly structure as exists in Arizona today, the uneconomic portion of utility investments is borne (day in and day out) by the utilities' captive ratepayers. Resuming retail choice does not make the uneconomic portion of the utilty portfolio higher or lower, but it certainly does shine a bright light on how vertically-integrated utilities have managed their procurement, and the extent to which their bundled customers are absorbing each and every element of risk embedded in those portfolios.

Assuming for discussion purposes only that if SRP is correct in its assertion that there would be substantial amounts of new stranded costs to be recovered, that is indeed unfortunate, but retail choice is not the culprit. The utlities prefer not to discuss just how poorly the vertically integrated utility model works to keep prices as low as possible. Stranded costs are not a "cost" of resuming retail choice; they are a result of monopoly utility procurement decisions. SRP's view that billions of new stranded dollars must be recouped is the most urgent reason of all for moving to retail choice as quickly as possible – to bring some competitive discipline and price pressure to utility procurement and to eliminate the potential for billions more ten years from now.

7. Retail choice implementation costs have proven to be trivial relative to benefits in competitive jurisdictions.

Opponents of retail choice, most notably the utilities, claim that the costs of implementing retail choice are exorbitant. They are wrong. First and foremost, they inappropriately include stranded costs in their estimates. As explained in Section 6 above, stranded costs should not be categorized that way because they must be paid whether or not there is retail choice. Second, they claim that the costs of RTO formation and membership must be included. Again, they are wrong. Membership in an RTO is not necessary for Arizona to move forward with retail choice, because the Arizona Independent Scheduling Administrator Association ("AZISA") is capable of managing the transmission scheduling functions necessary for the reopening of retail choice. As such, the costs versus benefits of RTO formation or membership can and should be evaluated separately. Moreover, the estimates provided by the utilities for what RTO membership would actually cost are unsupported and likely vastly overstated.

[60] See page 32 of SRP's opening comments

Quite simply, opponents' attempts to present the Commission with ill-conceived and unsupported statements about the implementation costs is another scare tactic designed to convince the Commission that it should abandon any further evaluation of the resumption of retail choice.[61] Reasonable and supported estimates of the costs for customer outreach and education, and bringing the AZISA into readiness to manage the transmission scheduling function were presented by the Retail Competition Advocates and RESA and AZISA in their opening comments. Further definition and refinement of those costs should be left to Phase 2 of this proceeding.

8. Retail competiton among alternative suppliers has had nothing to do with recent FERC action to settle and/or impose penalties with respect to wholesale market behavior.

Opponents of restructuring of the Arizona electricity market to allow for retail choice by consumers have erroneously pointed to enforcement actions by the Federal Energy Regulatory Commission (FERC) as evidence that the introduction of retail choice will increase market manipulation of wholesale electricity markets in Arizona. This conclusion is not true and is simply a scare tactic designed to make competition a villain.[62]

Competitive wholesale electricity markets and the electricity industry in general, remain among the most regulated markets and industries in the United States.[63] Comprehensive oversight of competitive wholesale electricity markets, which Congress mandated for the United States through Energy Policy Act of 1992,[64] and strengthened by the prohibition against market manipulation included in the Energy Policy Act of 2005,[65] is the primary responsibility of the FERC[66] today in Arizona and it will continue to be following the implementation of retail choice in Arizona.

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[61] Interestingly, APS comments that it spent $47 million on administrative costs for implementing retail choice, costs that APS had fully recovered as of 2010 (see page 13 of 35 of APS Exhibit A: APS Response to Staff Electric Restructuring Questions). Hopefully, APS is not suggesting that all of these sytems for which it has been fully reimbursed are lost, such that APS will have to start anew.....

[62] "Congress has taken a number of steps to facilitate competition in wholesale electric power markets. The Public Utility Regulatory Policies Act of 1978 (PURPA),5 the Energy Policy Act of 1992 (EPAct 1992),6 and EPAct 2005 promoted competition by lowering entry barriers and increasing transmission access. Federal electricity policies have sought to strengthen competition but continue to rely on a combination of competition and regulation." REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY, Pursuant to Section 1815 of the Energy Policy Act of 2005, Page 2, http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.

[63] See Attachment 17: "Regulation and Oversight of the Electric Power Industry," September 2010, page 1, http://www.competecoalition.com/files/Regulation%20and%20Oversight%20of%20the%20Electric%20Power%20Industry.pdf.

[64] Pub. L. No. 102-486, 106 Stat. 2776 (1992).

[65] 16 U.S.C. § 824v. *See also* 18 C.F.R. §1c.2.

[66] See Federal Power Act

In fact, after the implementation of retail choice, comprehensive regulation and oversight will continue at both the retail and wholesale levels. Strict oversight is required by various statutes, and oversight will remain strong, focused and comprehensive.

Price regulation in wholesale markets. Federal regulation ensures that rates for wholesale electricity sales and transmission service in interstate commerce are "just and reasonable" and that services are provided on a non-discriminatory basis.

Price regulation in retail markets. Prices and other terms of service in the retail markets, where service providers sell energy and other services to end-use consumers in Arizona, will be subject to the jurisdiction of the ACC.

Reliability and adequate resources. Oversight to ensure adequate resources and reliable system operations at both the federal and state levels is detailed, extensive and comprehensive, and will remain so under a retail choice program.

Financial security and transparency. Regulators have broad authority to ensure the financial security of electric utilities, and have adopted policies requiring prior approval and transparency regarding the asset transfers and other financial dealings of utilities. The financial risk management activities of electricity market participants are addressed by new requirements under the recent financial regulatory reform law known as Dodd-Frank.[67]

Additional oversight. In addition to comprehensive oversight by FERC and the ACC, the behavior of electric utilities is subject to review by other government authorities, such as the Federal Trade Commission, the Department of Justice, and the Commodity Futures Trading Commission.[68]

In short, competitive retail markets will continue to be monitored and regulated by the ACC. The ACC will have the authority as it does today to establish and enforce rules and regulations over distribution utilities and certificated competitive retail suppliers. The bottom line is that retail customers in Arizona will be protected by oversight from the ACC as they reap the benefits made available to them through competitive offers from licensed suppliers.

FERC rulings cited in the opposition comments are proof that FERC and other agencies are doing their job the same job they do in both regulated and restructured states. Enforcement by regulators sends a clear message to the industry that rules and customer protections are in place, regardless of underlying regulatory construct. Consumers can be confident that this is true now in Arizona and will continue after retail choice is enacted.

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[67] Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 124 Stat. 1376 (2010).

[68] *Regulation and Oversight of the Electric Power Industry*, *supra* note 42, at 16.

III.

CONCLUSION

The Commission has received from the opponents of retail choice a collection of innacurate and overblown arguments about the harm that retail choice will create. In short, unable to rely on facts to support their opposition, they resort to promoting unfounded fears in an effort to convince the Commission that it should abandon now any further consideration of retail choice in Arizona, rather that proceed to Phase 2 of this proceeding where comprehensive market rules and protocols for the implementation of retail choice will be developed and evaluated.

The factual record reflected in the opening and reply comments of the Retail Competition Advocates and RESA (as well as other supporters of retail competition) persuasively makes the case for the resumption of retail choice in Arizona at this time, and for moving forward now with Phase 2 of this proceeding. Specifically:

1. Retail competition will bring benefits to all rate classes, including residential customers.

2. Retail competition cannot be blamed for problems that coal may have as part of Arizona's future energy mix.

3. Retail choice will not cause FERC to usurp the Commission's authority; the ACC will retain authority over Arizona's energy policies.

4. The process and legal issues identified in the *Phelps Dodge* decision are easily avoided or ersolved through Commission process; no constitutional amendments are necessary.

5. Neither retail electric competition nor the resulting design of utiltiy POLR service (or any default service design) creates reliability risks for the Arizona electricity grid; such claims are pure fiction.

6. Retail competition does not create stranded costs but merely reveals the above market prices being paid by customers due to uneconomic investment and operating expenses associated with monopoly service.

7. Retail choice implementation costs have proven to be trivial relative to benefits in competitive jurisdictions.

8. Retail competition among alternative suppliers has had nothing to do with recent FERC action to settle and/or impose penalties with respect to wholesale market behavior.

Accordingly, for the reasons discussed in our July 15, 2013 Initial Comments and these Reply Comments, we urge the Members of the Commission to implement customer choice in electric service by moving this proceeding to Phase 2 as quickly as possible so that Arizonans can begin to reap the multitude benefits that only retail electric choice can deliver.

Dated this 16th day of August 2013.

Respectfully submitted,

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The original and thirteen (13) copies of the foregoing Comments will be mailed for filing this 16th day of August 2013 to:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

A copy of the foregoing Comments will be emailed or mailed this 16th day of August 2013 to:
All Parties of Record

Attachment 1

AECT COMMENTS ON THE TEXAS COALITION FOR AFFORDABLE POWER'S (TCAP'S) VIEWS ON ELECTRIC PRICES IN THE COMPETITIVE ELECTRIC MARKET

Introduction

TCAP's pricing analysis is built on the premise that electricity prices are higher today than they were in 1999. This simplistic analysis is simply not valid. It is built on a faulty premise that ignores the impacts of natural gas prices and infrastructure investment while choosing a 1999 base year for multiple comparisons which simply does not make sense.

Additionally, it relies on data that does not accurately reflect the competitive market or the role of customers in choosing products that meet their needs. As shown below, TCAP selectively provides only pieces of the statistical story behind electricity prices in ERCOT in hopes that its audience will draw an erroneous conclusion.

These conceptual and statistical failings are endemic throughout TCAP's analysis of the competitive electric market.

Section 1: Overview of Fundamental Flaws in TCAP's Methodology

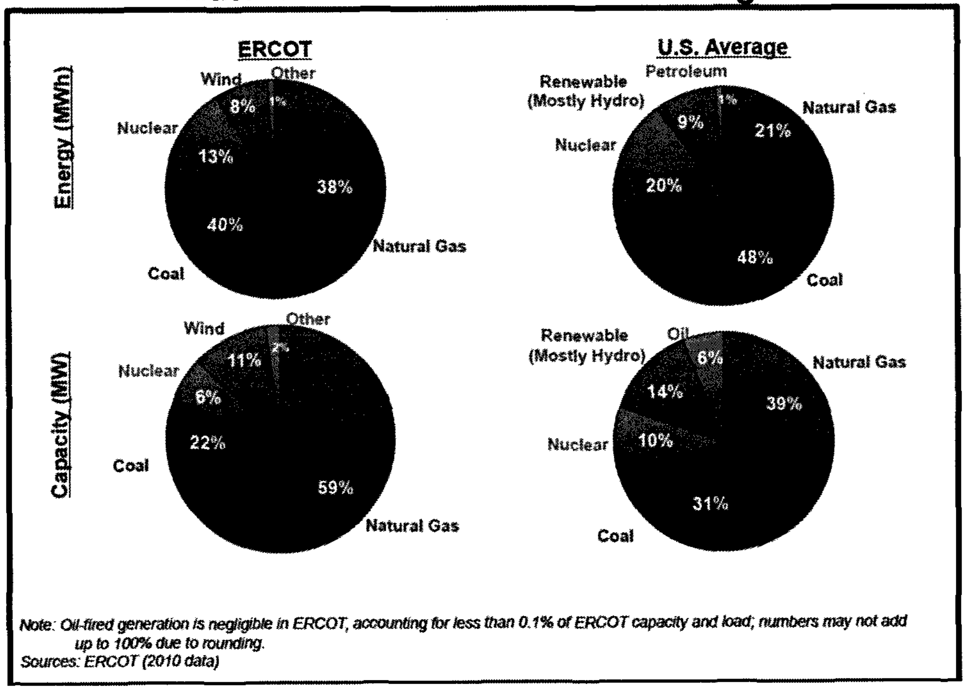
1.1 TCAP Largely Ignores the Impact of Natural Gas on Power Prices

Retail power prices are linked to wholesale power prices. Wholesale power prices are driven by prices of the fuel used to generate electricity. That is true of fully regulated or competitive market as well utilities owned by a municipality or rural cooperative.

In ERCOT, fluctuations in demand are met by natural gas-fired generation at nearly all times. As a result, natural gas tends to drive the price for wholesale power. The process is more complex, but the result is that changes in natural gas prices correlate highly with changes in wholesale power prices in ERCOT.

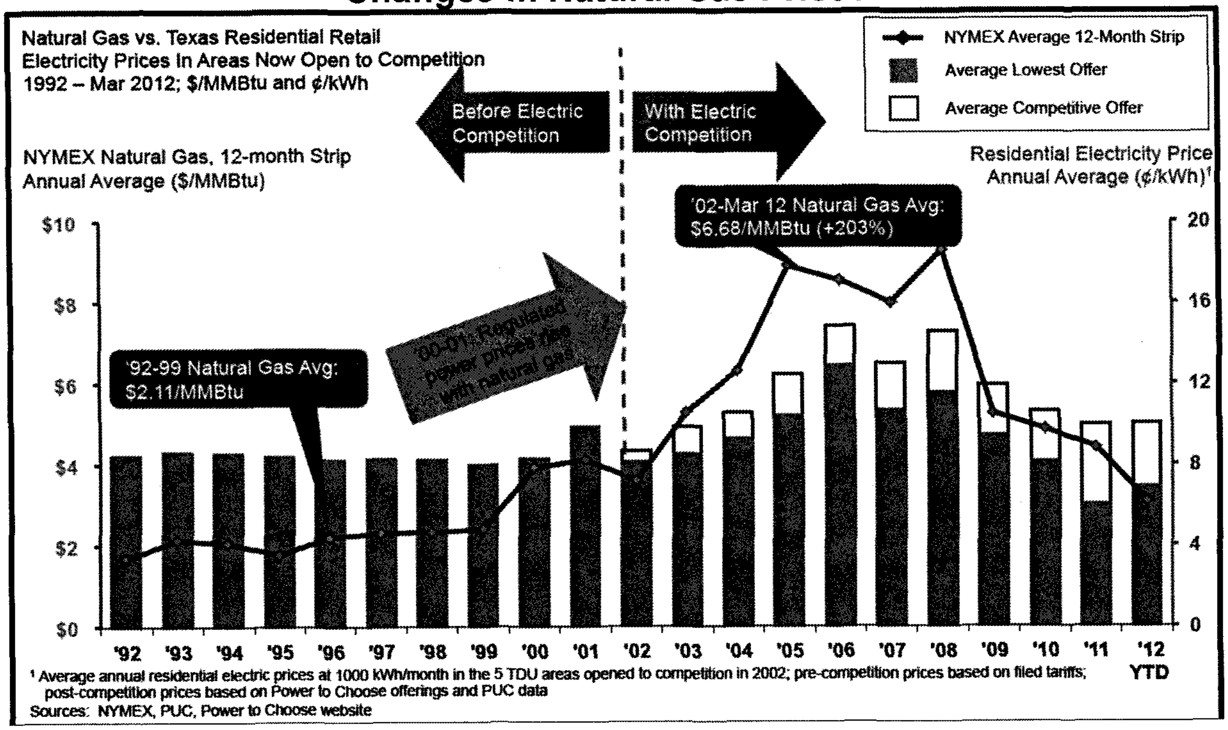
Thus, no model can ignore the physical and economic reality of a region's wholesale generation fuel mix and the global commodity markets that drive the prices of the fuels used to generate electricity. ERCOT is uniquely dependent on natural gas, so the fact that ERCOT's wholesale and retail power prices respond to natural gas prices is not surprising.

ERCOT Energy Use More Dependent on Natural Gas Than the U.S. Average



Note: Oil-fired generation is negligible in ERCOT, accounting for less than 0.1% of ERCOT capacity and load; numbers may not add up to 100% due to rounding.
Sources: ERCOT (2010 data)

Residential Electricity Prices Tend to Follow Changes in Natural Gas Prices



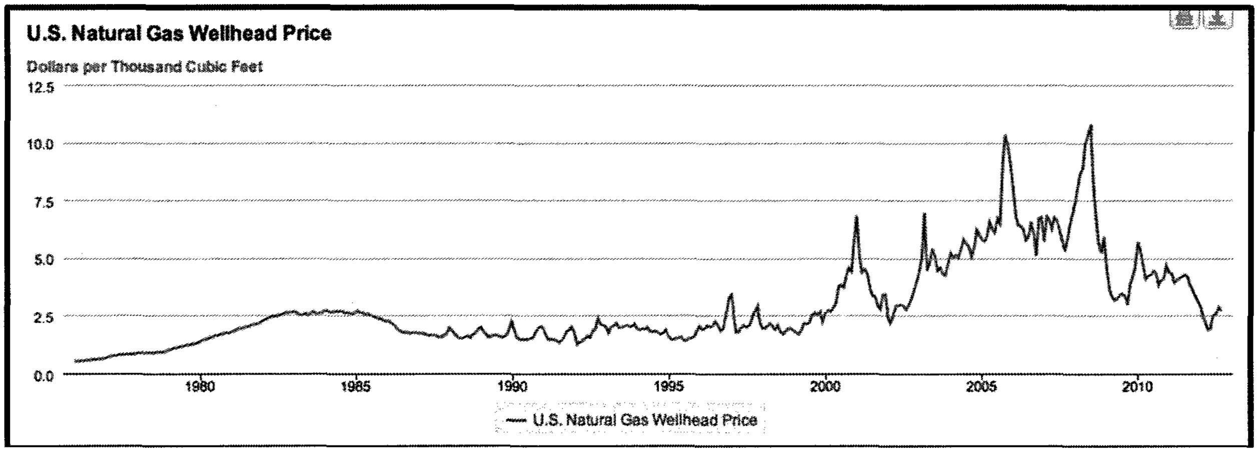
¹ Average annual residential electric prices at 1000 kWh/month in the 5 TDU areas opened to competition in 2002; pre-competition prices based on filed tariffs; post-competition prices based on Power to Choose offerings and PUC data
Sources: NYMEX, PUC, Power to Choose website

1.2 TCAP Chooses its Baseline Data to Pre-Engineer Its "Findings"

TCAP provides no reasonable justification for using 1999 as the baseline to measure electricity prices in several of its analyses. TCAP suggests 1999 is an appropriate starting point for measuring electricity prices, based on the timing of legislative passage of the restructuring law (SB7).

The fact is, 1999 was the tail end of a period of great stability in the natural gas market as shown below.

Wellhead Natural Gas Prices Have Been Volatile Since 2000



Source: Energy Information Administration

It is difficult to choose a year <u>less</u> representative of the cost of gas over the past decade than 1999. To put it in starker terms, the average wellhead NYMEX gas price per year is shown below (source: EIA).

Year	NYMEX Average Gas Price ($/MMBtu)	Increase from 1999
1999	2.19	---
2000	3.68	**68%**
2001	4.00	**83%**
2002	2.95	**35%**
2003	4.88	**123%**
2004	5.46	**149%**
2005	7.33	**235%**
2006	6.39	**192%**
2007	6.25	**185%**
2008	7.97	**264%**
2009	3.67	**68%**
2010	4.48	**105%**
2011	3.95	**80%**
2012 (Sept.)	2.71	**24%**

TCAP selectively chose 1999 as a starting point because natural gas and electricity prices were very low. This allows TCAP to pre-engineer its findings to support its anti-competitive agenda.

Many comparisons that TCAP provides are based on price increases since 1999, the last year of sustained, low natural gas prices that has little correlation with the commodity during the 2000s.

In fact, Texas' annual statewide average price in 1999 was the lowest of any of the past 20 years. Moreover, TCAP's starting point for its subsequent analysis conspicuously avoids the reality, or even mention of, the volatile swings in natural gas prices beginning in late 2000 or the massive infrastructure investment required to support Texas' economic growth.

Regarding the timing of when competition "began," the relevant date is NOT when the restructuring law (SB7) was passed. Instead, the more relevant date is when the law was effective and implemented for retail pricing.

Retail power prices were still fully regulated in 1999, 2000, and 2001. At the time, utilities were authorized to adjust the fuel component of their prices twice per year. But, they were required to file special exceptions to adjust prices more frequently to recover the increased cost for natural gas.

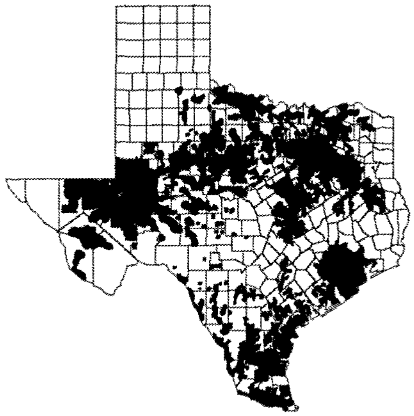
TCAP's analysis of the competitive market captures increased prices resulting from increased wholesale power prices, which were fueled by rising natural gas costs that occurred in a still-regulated market.

The transition to competition for residential customers started in January 2002. Any comparison of prices prior to the start of competition should use late 2001 as a starting point. The transition to competition was completed in 2007 with the expiration of the mandatory "Price to Beat," which was a pricing mechanism approved by the PUC that each REP formerly affiliated with the region's transmission and distribution utility was required to offer. In essence, the "Price to Beat" was a regulated price in the marketplace.

1.3 TCAP Often Relies on EIA Statewide Data for Its Comparisons

Statewide EIA data is not indicative of pricing in the competitive regions of Texas, which are a subset of the state. Statewide EIA data simply—and only—reflects the retail revenue rates across the various market models, i.e. competitive, regulated, municipal and cooperative, and wholesale power markets included within our state's borders.

Statewide EIA "price" data is simply a sum of revenues divided by sales volumes across the entire state. As shown below, the competitive areas of Texas do not comprise the entirety of the state—in fact, competitive retail electric providers (REPs) serve just over 60 percent of the residential load in Texas.



Competitive Areas of Texas

EIA's approach is not an unreasonable way to study regulated markets where all customers pay essentially the same rate. But, it is never representative of current prices in the ERCOT competitive market or current market conditions. The EIA electric price data reflects historic prices, not the offers available in a dynamic, competitive market that frequently change and where customers can choose offers and products that suit their specific needs.

1.4 TCAP Does Not Take Into Account Offers Available in Competitive Areas

It's relatively easy to survey prices in regulated areas where everyone pays the same rate. To assess a competitive market, however, the analysis must be built on the observable offer prices available to customers. In, Texas, those offers are easily found at www.PowertoChoose.org, the PUC's electric choice website.

The 'price' that customers pay for electricity in a competitive market is the result of numerous individual decisions based on a variety of individual preferences. Trying to distill that distribution of choices down to a single average number tells us little. We believe the offers available in the competitive market — and changes in offer prices — provide the most effective snapshot of its performance.

1.5 TCAP Does Not Account For, Or Even Evaluate, Structural Differences Between Competitive and Non-Competitive Areas of Texas

TCAP uses some data in their report which purports to review the prices of two groups – areas of Texas "with deregulation" and areas "outside deregulation." We presume they are trying to draw a distinction between competitive retail areas of Texas and other areas which are served by a mix of municipal utilities, co-ops, and integrated utilities outside the ERCOT region (i.e., non-competitive areas). However, there are significant issues with this kind of generalized analysis. For instance, the data TCAP utilizes from EIA is quite lagged and these other entities do not allow their customers to choose the offers and providers that best meet their needs. Also, the approach does not make an apples-to-apples comparison due to structural differences among the various providers as discussed further below.

Integrated utilities outside ERCOT participate in different wholesale markets where the fuel mix for generation is more dependant upon coal. These also tend to be lower growth areas than the ERCOT region so lower investment is required to maintain reliable electric supply. Additionally, there is an inherent regulatory lag in these areas which results in slower adjustments to market conditions vis-à-vis the ERCOT region. When summed together, these areas are not a good comparison to competitive areas nor are they a proxy to what competitive areas of the state would have done outside industry restructuring.

The municipal providers (munis) and co-ops within Texas are another group that cannot be easily compared to the competitive market.

- Some munis and co-ops have a different generation mix with more emphasis on coal. Similarly, some of these entities secured long-term supply arrangements with baseload coal and nuclear plants at prices below current market
- Co-ops can be eligible for federal USDA Rural Utility Service programs, such as grants and subsidized low or no interest loans with generous principal repayment deferral terms.
- Many munis and co-ops are exempt from property taxes, sales taxes and several regulatory costs like System Benefit Fund and franchise fees. They are also not for profit entities.
- Munis hold a preferential city zoning approval position and the ability to benefit from cross-subsidies by sharing facilities, services and personnel with other city departments.
- Munis and co-ops may benefit from generation contracts from other government and non-profit entities, which also benefit from the same financial and regulatory privileges as munis and co-ops that distribute power.
- Munis and co-ops have "captive" customer bases. This allows them to enter into long-term hedging contracts while their customers hold associated risks. They can also provide subsidies among the customer classes if desired and reduce servicing costs as they deem appropriate.

In truth, the range of prices in areas of Texas that now have retail competition and those that do not was very broad prior to electric restructuring. Today, and over the past several years, surveys show that competitive prices in Texas compare favorably to non-competitive areas.

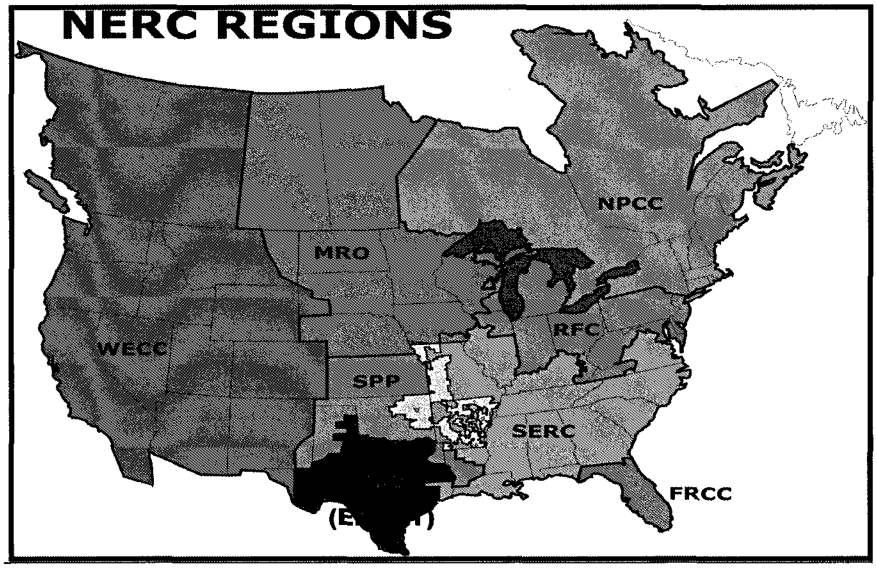
Simply put, samples of Texas non-competitive areas reveal that several have prices consistent with or higher than those available in the competitive market. A review of the PUC's Power to Choose website helps customers assess their competitive pricing options. Today, some of the lowest prices in Texas are available in competitive areas and the average Texas competitive offer price is nearly 2¢/kWh below the latest Texas state average price available from TCAP's data source (EIA). It must be remembered that EIA data is never representative of current prices in the ERCOT competitive market or current market conditions. The EIA electric price data reflects historic prices, not the offers available in a dynamic, competitive market that frequently change and where customers can choose offers and products that suit their specific needs.

1.6 TCAP Mistakes State Boundaries for Power Market Boundaries

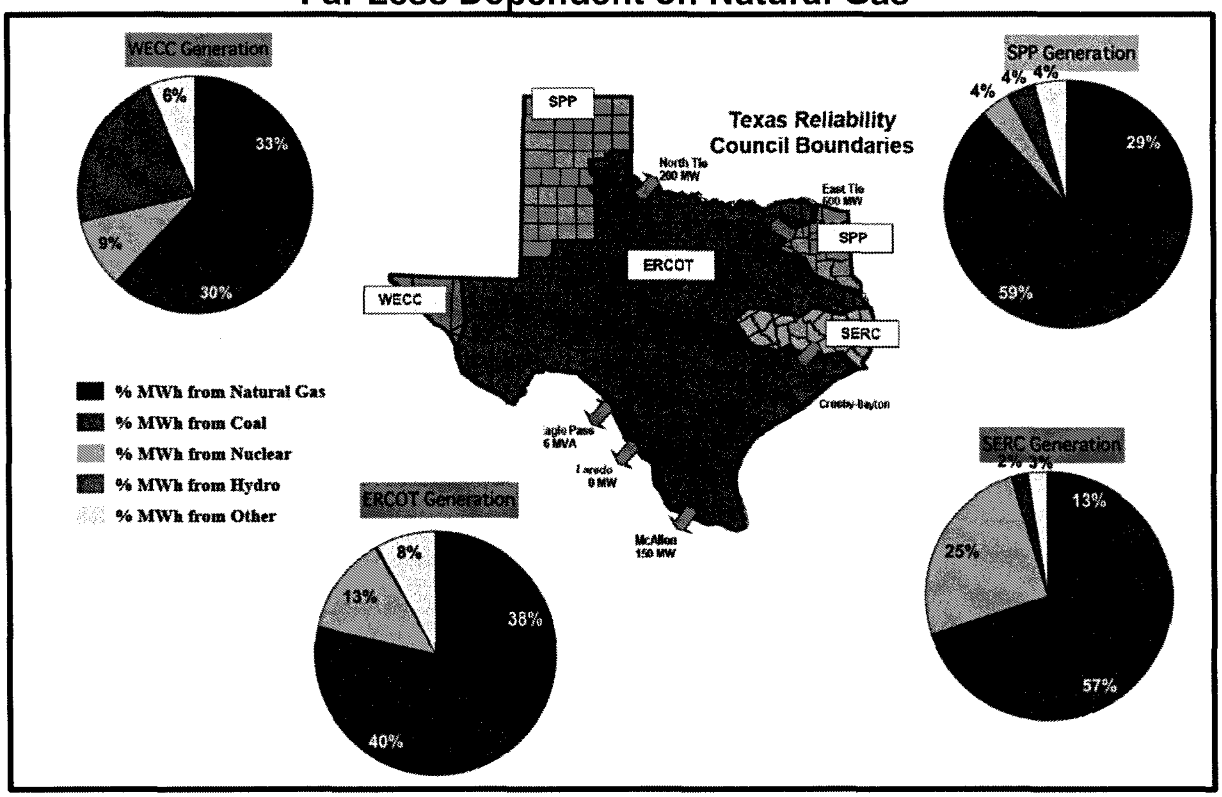
While 85 percent of Texas' load is served by ERCOT, nearly every other electric grid independent system operator (ISO) covers all or portions of multiple states. For example, the Western Electricity Coordinating Council (WECC) grid runs from west of El Paso to California and north to British Columbia. Some states, like Louisiana are part of more than one electric grid, which includes all or part of over a dozen Southeastern and Midwestern states.

This complexity among multi-state ISOs affects how you assess electric prices—and especially the fuel mix. While Louisiana provides a lot of natural gas generation, coal is the predominant fuel source in both the SERC Reliability Corporation and the Southwest Power Pool (SPP), which cover the state. Oklahoma is also a member of the Southwest Power Pool (SPP) and shares its fuel mix.

Regions Outside Texas Part of Larger, Multi-State Grids



Regions That Include Adjacent States Far Less Dependent on Natural Gas



Sources: ERCOT, 2011 data; US Average, EIA, 2010 data

1.7 TCAP Ignores Other Benefits of Choice in the Competitive Market

With dozens of REPs competing for residential business, the ERCOT market has a wide range of products including renewable sources of energy, varying lengths of agreements, and other products which allow a customer greater control of their usage.

In addition, the competitive market has encouraged the adoption of renewable generation—especially wind—and it is well-positioned for customers to benefit from REPs providing products that use the smart grid. Customers in ERCOT have fully embraced the goals of competitive market: the freedom to choose competitively priced products and services that best suit their needs rather than 'one-size-fits-all' solutions of strictly regulated markets.

1.8 TCAP Fails to Consider the Impact of New Investment to Meet Population and Economic Growth

Texas is a fast-growing state. It leads the nation in new residents and economic development — both of which require electricity. Generators in Texas have invested over $40 billion in the state since 1999 to build new electric generating facilities. Many of Texas' older generation plants have been replaced with cleaner generation, while retrofitting others ensure they exceed state and national clean-air requirements.

Retail electric providers have also invested in customer systems and marketing channels to meet the needs of Texas consumers. Private investors, not ratepayers, have assumed the risks of these massive generation and retail investments. That protects customers from risks associated with these projects (e.g. cost overruns or outdated technologies). Similarly, utilities have invested heavily to keep up with rising electric demand. TCAP's analysis does not take these investments into account.

Summary

TCAP's analysis is deeply flawed in the way it depicts prices in the competitive Texas electricity market. The fact is, in a market where consumers have choice and control, a quick review of PowertoChoose.org demonstrates that there are numerous prices available today that are lower than the last regulated rates. More importantly, consumers can choose the provider, the plan and the price that best meets their individual needs.

The real promise of competition provides consumers a choice of competitively priced electricity and unlocks innovation of products and services. That promise has been, and continues to be, kept every day.

Section 2: Notes on TCAP Summary Statements in "The Story of ERCOT" (page 10)

TCAP: "Texans in deregulated areas consistently have paid more for power than Texans outside deregulation." (Page 2)

AECT Comments:

- The statement by TCAP does not account for the effect of natural gas on electricity prices. (see §1.1)
- TCAP has chosen a baseline year of 1999 that is not reflective of the market, and is used to pre-engineer TCAP's findings. (see §1.2)
- Statewide EIA data is not indicative of pricing in the competitive regions, failing to reflect the dynamic changes in the competitive market. (see §1.3)
- TCAP does not take into account the offers available in competitive areas, which provide a more accurate picture of market performance. (see §1.4)
- Wholesale power markets don't follow state boundaries. And it's the generation fuel mix that can be accessed via power markets, not the generation fuel within a state's boundaries, that is relevant here. (see §1.6)

******

TCAP: "Had residential prices kept to the national average after deregulation, Texans would have saved more than $10 billion." (Page 3)

AECT Comments:

- Given that the predominant fuel for generating electricity in the rest of the nation is coal, it is misleading to calculate savings based on the assumption that there was any possible way Texas could have had prices equal to the national average during the past 9 years of volatile gas prices. (see §1.1)
- TCAP relies entirely EIA statewide data, which is not indicative of the competitive market and ignores prices available in the competitive market for its comparisons. (see §1.3 and §1.4)
- TCAP ignores the other benefits of choice in the competitive market, as well the benefit of investment in new infrastructure to meet growth needs. (see §1.7 and §1.8)

TCAP: "Residential electricity prices remained consistently below the national average before the retail electric deregulation law, and consistently above the national average after deregulation." (Page 3)

AECT Comments:

- TCAP discounts the effect of natural gas on electricity prices. (see §1.1)
- Statewide EIA data is not indicative of pricing in the competitive regions, failing to reflect the dynamic changes in the competitive market. (see §1.3)

******

TCAP: "Texas Leads Most Deregulated States for Price Increases for Price Increases, 1999-2012." (Page 6)

AECT Comments:

- The statement by TCAP does not account for the effect of natural gas on electricity prices. (see §1.1)
- TCAP has chosen a baseline year of 1999 that is not reflective of the market, and is used to pre-engineer TCAP's findings. (see §1.2)
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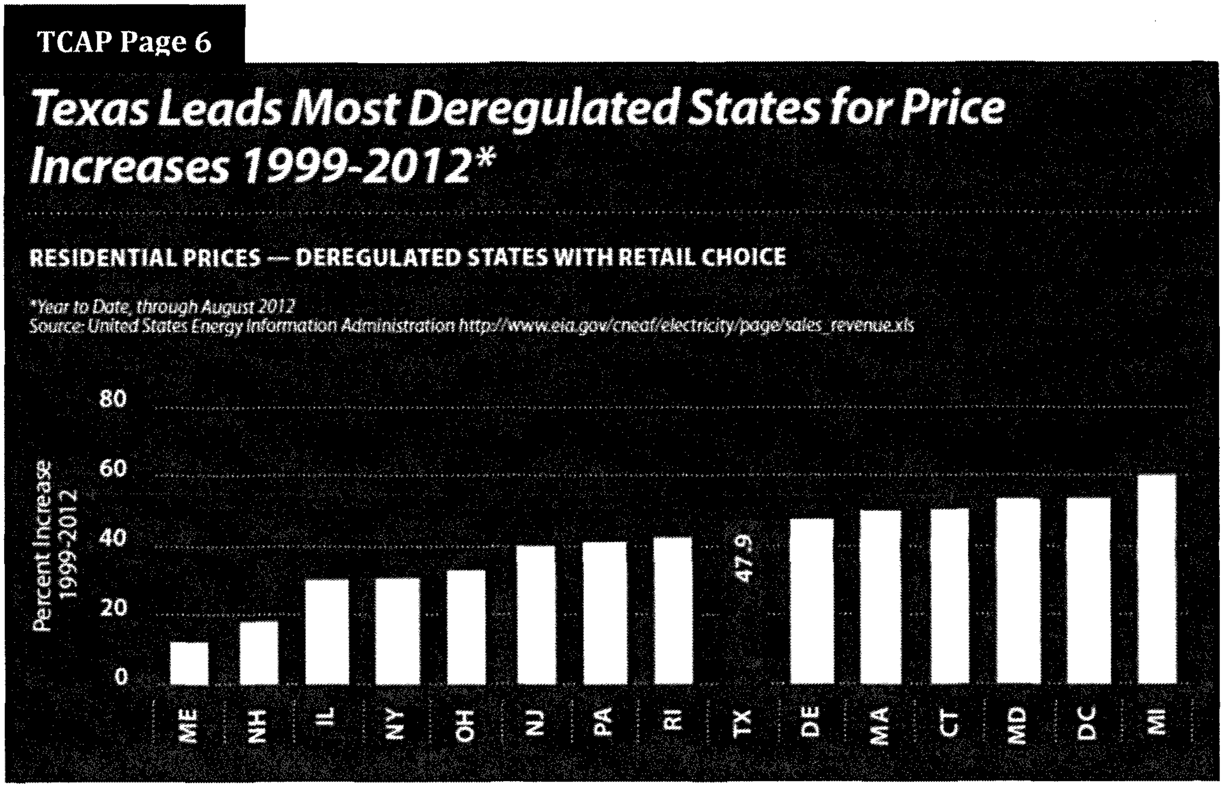
- TCAP fails to consider the impact of new investment in Texas to meet population and economic growth, especially compared to nearby states with less powerful economies. (see §1.8)

Section 3: Notes on TCAP Charts in "Deregulated Electricity in Texas: A History of Retail Competition"

Note: TCAP includes several other charts that use the same data in similar ways.



AECT Comments:

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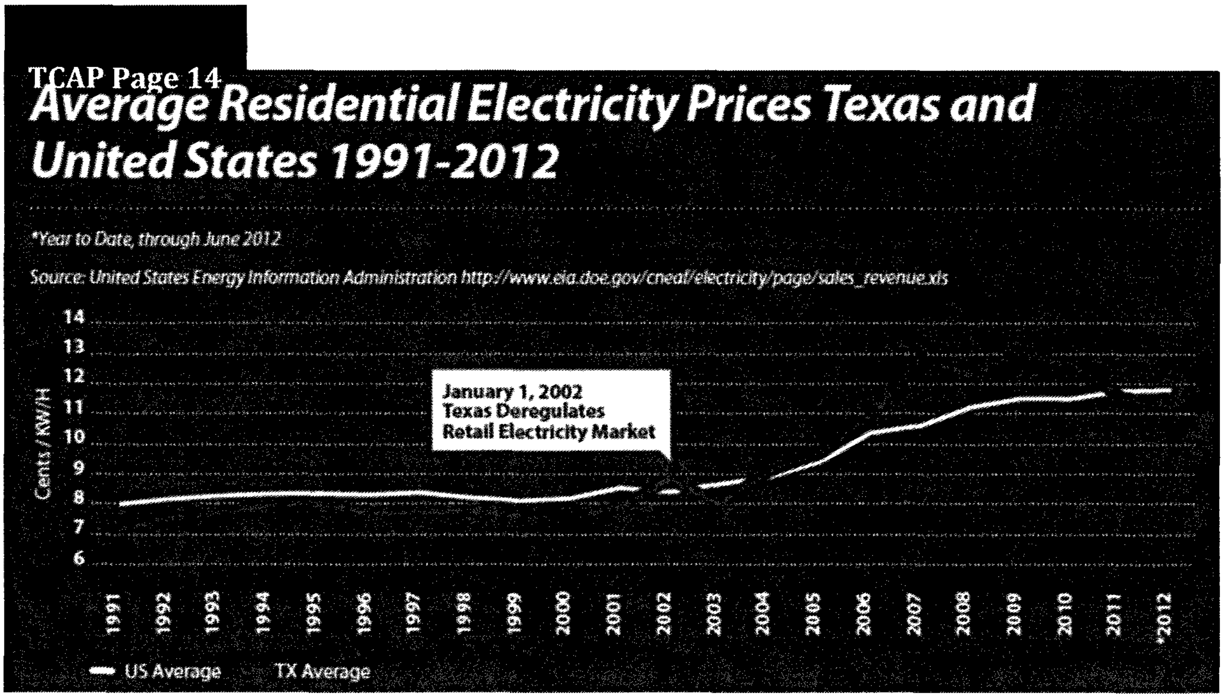
- Wholesale power markets don't follow state boundaries. And it's the generation fuel mix within those wholesale power markets, not the generation fuel within a state's boundaries, that is relevant here. (see §1.6)
- TCAP fails to consider the impact of new generation in Texas to meet population and economic growth, especially compared to nearby states with less powerful economies. (see §1.8)

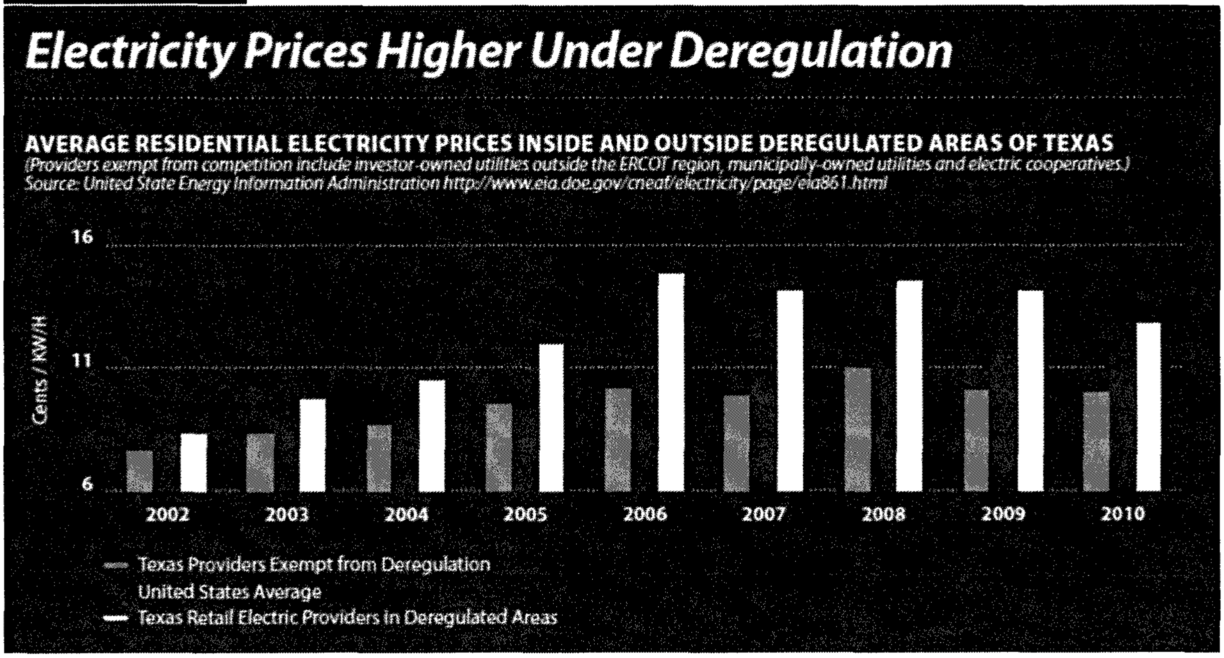
TCAP Page 14



AECT Comments:

- TCAP discounts the effect of natural gas on electricity prices. (see §1.1)
- TCAP has chosen a baseline year of 1999 that is not reflective of the market, and is used to pre-engineer TCAP's findings. (see §1.2)
- Statewide EIA data is not indicative of pricing in the competitive regions, failing to reflect the dynamic changes in the competitive market. (see §1.3)
- TCAP does not take into account the offers available in competitive areas, which provide a more accurate picture of market performance. (see §1.4)
- TCAP's data ends in 2009 which is very misleading; 2010 has seen a rapid decrease in electric prices offered in the competitive market. Also, and despite the limitations of TCAP's data source, even that clearly shows that Texas average prices are now below the US average.
- TCAP has also chosen to use a range of 6¢/kWh to 14¢/kWh to exaggerate the steepness of the slope.

TCAP Page 26



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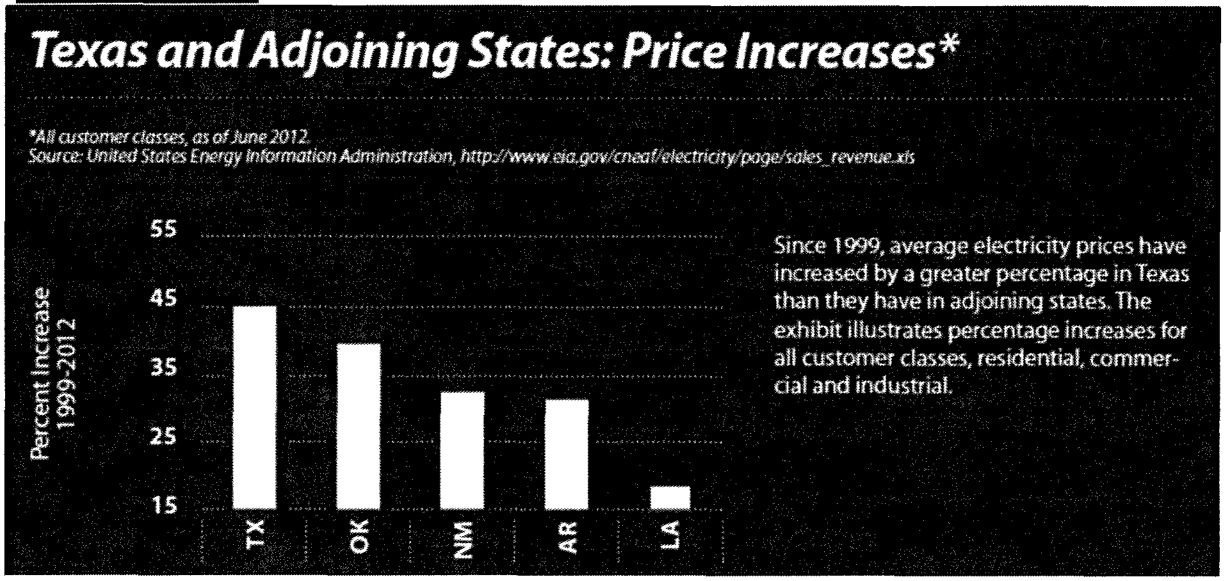
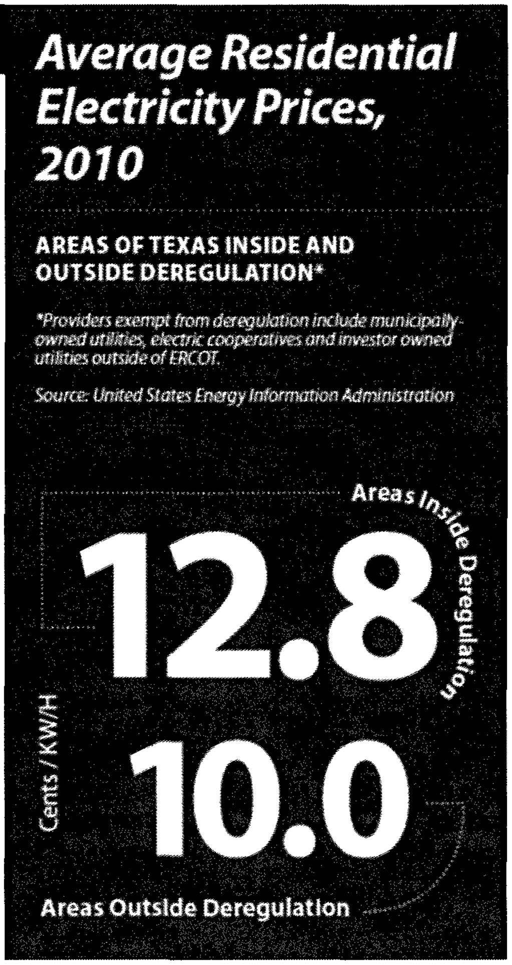
TCAP Page 42



AECT Comments:

- Wholesale power markets don't follow state boundaries. And it's the generation fuel mix within those wholesale power markets, not the generation fuel within a state's boundaries, that is relevant here. (see §1.6)
- TCAP often cites Louisiana because it's the only state adjacent to Texas that has a large percentage of natural gas generation. However, most of Louisiana is part of SERC and SPP, multi-state electric grids that are dependent on coal.
- Further, Louisiana has seen little population growth and little investment in new industry, whereas TX has seen billions of dollars in private investment that has helped enable our economy to grow. (see §1.8)

TCAP Page 60



AECT Comments:

- TCAP discounts the effect of natural gas on electricity prices. (see §1.1)
- TCAP does not take into account the offers available in competitive areas, which provide a more accurate picture of market performance. (see §1.4)
- TCAP does not take into account structural differences between competitive and non-competitive areas such as generation fuel mix, supply agreements, investment requirements, cross-subsidies, taxes, and competitive market dynamics. (see §1.5)
- TCAP ignores the benefits of competition in the market, including the ability of consumers to choose products that meet individual needs, as well as promotion of renewable generation, smart meters and other innovations. (see §1.7)
- TCAP fails to consider the impact of new generation in Texas to meet population and economic growth, especially compared to nearby states with less powerful economies. (see §1.8)

Attachment 2

States with Restructured Electricity Markets Post Lower Rates of Change

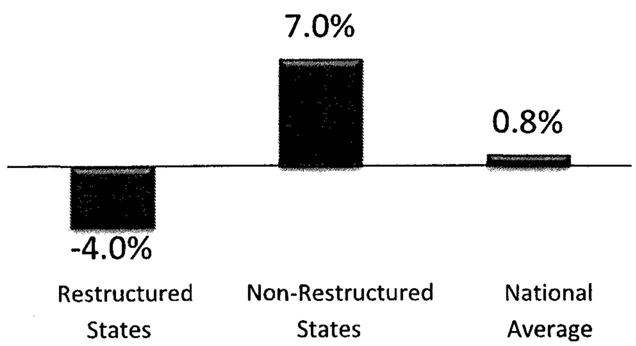
Comparison of Rate Changes Across Electricity Markets – 1997-2012

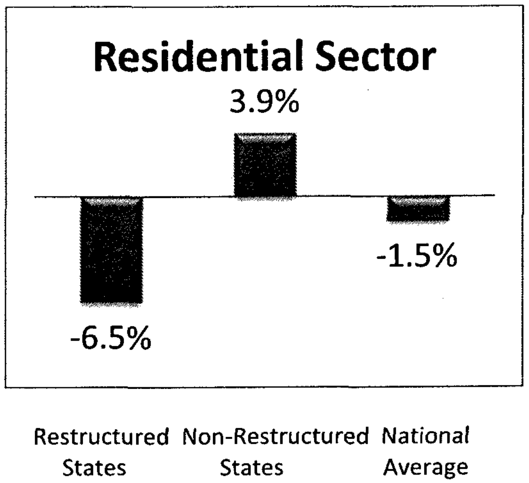
*Restructured States vs. Non-Restructured States**

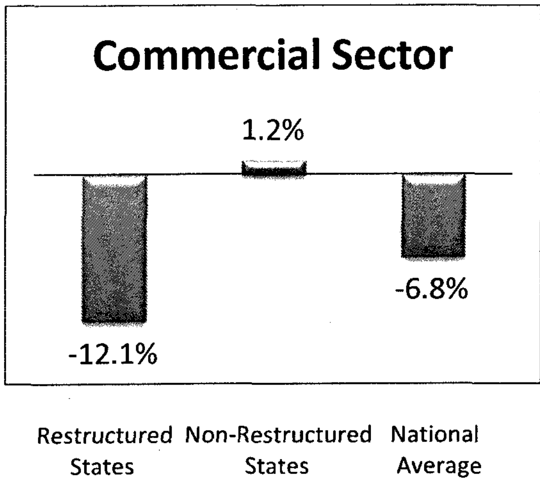
COMPETE

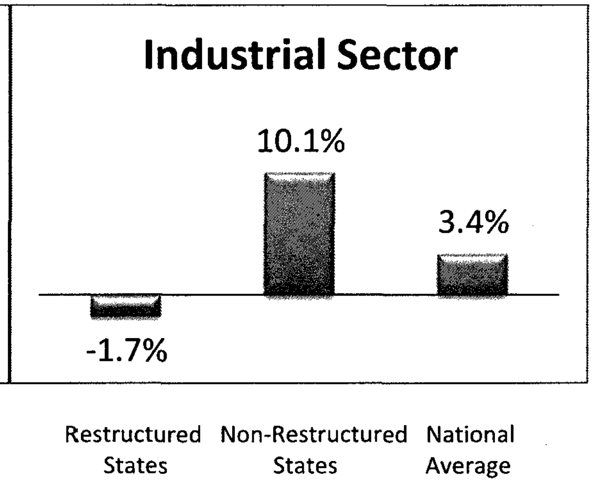
Electricity Competition Drives Innovation and Consumer Benefits

Rate Change: All Sectors









* Restructured States include CA, CT, DE, IL, MA, MD, ME, MI, MT, NH, NJ, NY, OH, PA, RI, TX, and DC (17 states). These reflect states with active retail choice programs (15 states) and states with inactive/suspended retail choice programs but large portions of generation provided by Independent Power Producers (2 states). CA and MT fall in the latter category with less than 50% of net generation provided by electric utilities in 2010.

Results were calculated using price information from the U.S. Energy Information Administration (EIA) and a Consumer Price Index of Urban Consumers (CPI-U) of 43% for the period between 1997 and 2012. Sources: EIA and The Bureau of Labor Statistics)

Attachment 3

JDPower Panel Client Login

Press Release

2012 Texas Residential Retail Electric Provider Customer Satisfaction Study

Date Published: 08/15/2012

J.D. Power and Associates Reports:
Deregulation of Texas Retail Electric Market Leads to Increasingly Satisfied Customers.
Texas Electric Customers Are Now More Satisfied With Electric Retailers than With Regulated Utilities

Champion Energy Services Ranks Highest in Customer Satisfaction with Texas Residential Retail Electric Service Providers for a Third Consecutive Year

WESTLAKE VILLAGE, *Calif.*: 15 August 2012 -- Customers in Texas who are able to choose their electric provider are increasingly more satisfied with their provider than are those who do not have a choice, according to the J.D. Power and Associates 2012 Texas Residential Retail Electric Provider Customer Satisfaction Study^{SM} released today.

The study, now in its fifth year, measures customer satisfaction with retail electric service providers in Texas by examining four key factors (listed in order of importance): price; billing and payment; communications; and customer service.

Overall satisfaction among residential customers of electric retailers in Texas is 678 (on a 1,000-point scale), an increase of 44 points from 2010. This is the highest level since the study was first published in 2008. Moreover, this is the first time satisfaction among customers with a retail choice of electric providers exceeds both the Texas and U.S. national averages for all factors measured in the study. Among Texas customers with regulated residential electric service, satisfaction is 646. Regionally, satisfaction among customers in the Metropolitan Dallas/Fort Worth area is 677, compared with 681 among those in the Houston area, three points higher than the statewide average.

At the factor level, satisfaction with customer service has increased the most from 2011, up 45 points to 744. Contributing to the significant increase in customer service satisfaction are improvements in call center performance (+47 points) and online customer service (+38). Satisfaction has increased in the other three factors as well: price (+20 points); communications (+19) and billing and payment (+16).

"Many electric retailers in Texas are considering how to better serve their customers when they are contacted," said Andrew Heath, senior director of the energy and utility practice at J.D. Power and Associates. "The large improvements show that electric retailers are putting practices in place that improve satisfaction, which helps retain customers."

Satisfaction is 218 points higher when customers' questions or problems are resolved on the first call, compared with when their questions or problems require two or more calls for resolution (799 vs. 581, respectively). Similarly, online customer service interactions echo the need for quick resolution, as satisfaction with customer service is 800 among customers whose questions or problems are resolved on their first visit to the website, compared with 644 when problem resolution requires two or more visits.

"Customers do not want to spend much time getting an answer or fixing a problem with their bill or service," said Heath. "The dramatic increase in satisfaction for first-contact resolution is a clear indicator that Texas electric companies should strive to quickly resolve issues or questions."

Among customers who are aware of their retailer electric provider's corporate citizenship efforts--such as supporting local organizations or volunteering in the community--satisfaction averages more than 60 points higher than among those who are not aware of such efforts.

Texas Residential Electric Retail Results
Champion Energy Services ranks highest among retail electric utility providers in Texas for a third consecutive year with a score of 756. Champion Energy Services performs particularly well in billing and payment, price and customer service. Following in the rankings are Bounce Energy (745) and StarTex Power (729).

The 2012 Texas Residential Retail Electric Provider Customer Satisfaction Study is based on responses from 7,619 residential customers of electric retailers in Texas. The study was fielded between September 2011 and June 2012.

For more information, view Texas residential retail electric service provider ratings at JDPower.com.

About J.D. Power and Associates
Headquartered in Westlake Village, Calif., J.D. Power and Associates is a global marketing information services company operating in key business sectors including market research, forecasting, performance improvement, Web intelligence and customer satisfaction. The company's quality and satisfaction measurements are based on responses from millions of consumers annually. For more information on car reviews and ratings, car insurance, health insurance, cell phone ratings, and more, please visit JDPower.com. J.D. Power and Associates is a business unit of The McGraw-Hill Companies.

About The McGraw-Hill Companies
McGraw-Hill announced on September 12, 2011, its intention to separate into two companies: McGraw-Hill Financial, a leading provider of content and analytics to global financial markets, and McGraw-Hill Education, a leading education company focused on digital learning and education services worldwide. McGraw-Hill Financial's leading brands include Standard & Poor's Ratings Services, S&P Capital IQ, S&P Dow Jones Indices, Platts energy information services and J.D. Power and Associates. With sales of $6.2 billion in 2011, the Corporation has

approximately 23,000 employees across more than 280 offices in 40 countries. Additional information is available at http://www.mcgraw-hill.com/.

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Syvetril Perryman; Westlake Village, Calif.; (805) 418-8103; media.relations@jdpa.com

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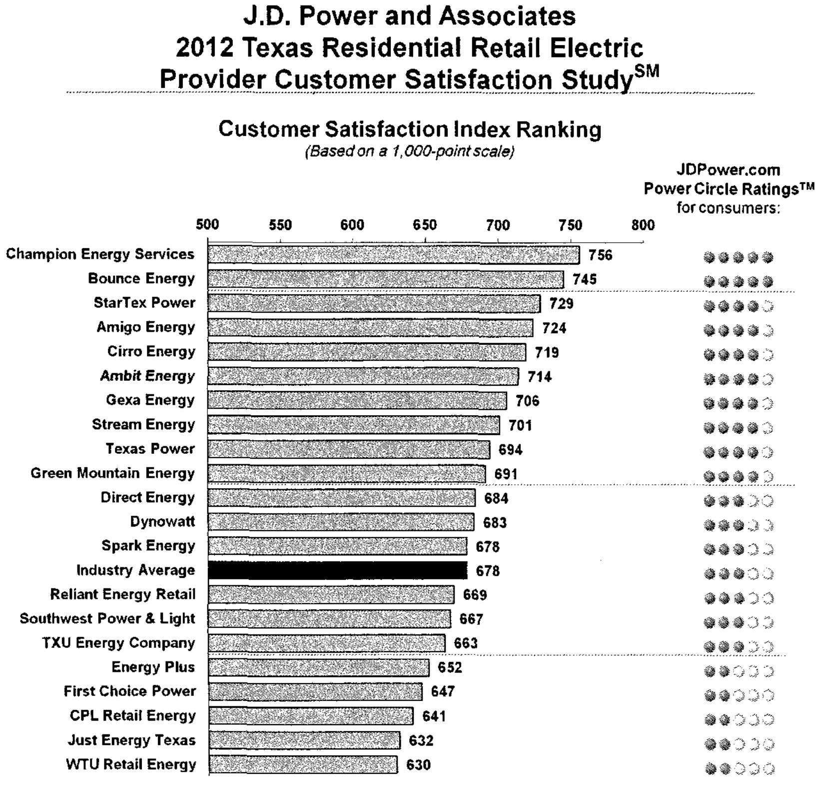

Included in the study, but not ranked due to small sample size are APG&E, Brilliant Energy, dPi Energy, Gateway Energy Services, Kinetic Energy, Mega Energy, MX Energy, Nueces Electric Cooperative, Potentia Energy, Tara Energy, Texpo Energy, True Electric, and YEP Energy.

Source: J.D. Power and Associates 2012 Texas Residential Retail Electric Provider Customer Satisfaction Study℠

Power Circle Ratings Legend
○○○○○ *Among the best*
○○○○○ *Better than most*
○○○○○ *About average*
○○○○○ *The rest*

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2013 Texas Residential Retail Electric Provider Customer Satisfaction Study
2013 Canadian Customer Commitment Index Study
2013 Brazil Vehicle Ownership Satisfaction Study
2013 Appliance Retailer Satisfaction Study
Valley View Hospital Recognized Again for Providing Outstanding Inpatient and Emergency Department Experiences

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2013 Taiwan Sales Satisfaction Index (SSI)

Attachment 4

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Press Release

2013 Texas Residential Retail Electric Provider Customer Satisfaction Study

Date Published: 08/14/2013

J.D. Power Reports:

Customers of Texas Retail Electric Providers Are More Satisfied Than Customers of Regulated Utilities, Driven Primarily by Price

Champion Energy Services Ranks Highest in Customer Satisfaction with Texas Residential Retail Electric Providers for a Fourth Consecutive Year

WESTLAKE VILLAGE, Calif.: 14 August 2013--Price is the primary reason that satisfaction is higher among customers who use a Texas retail electric provider than among those who use a regulated utility, according to the J.D. Power 2013 Texas Residential Retail Electric Provider Customer Satisfaction Study[SM] released today.

The study, now in its sixth year, measures customer satisfaction with retail electric service providers in Texas by examining six key factors (listed in order of importance): price; billing and payment; corporate citizenship; communications; enrollment/renewal; and customer service.

Overall satisfaction among customers of retail residential electric providers (REPs) in Texas is 682 (on a 1,000-point scale), an increase of 4 points from 2012. This is the highest score since the study was first published in 2008.

Customer satisfaction with price, a primary driver of satisfaction in the study, increases 20 points to 684 from 2012. The average perceived price per kilowatt hour (kWh) has declined to 10.4 cents in 2013 from 10.7 cents in 2012. Texas electric retail providers outperform regulated utilities in Texas by 114 points in the price factor (684 vs. 570, respectively).

Key Findings

-Customer satisfaction with price increases 20 points to 684 from 2012.
-Price satisfaction is highest among customers whose residential electric provider makes them aware of energy-savings measures available.
-Corporate citizenship and enrollment/renewal, two new factors in the 2013 study, premiere as important influencers of customer satisfaction.

"Deregulation of the residential electric market in Texas opened the doors to healthy price competition and also focused residential customers on finding the cost savings and service programs that match their needs," said Chris Oberle, senior director of the energy practice at J.D. Power. "Satisfaction isn't just about price. Retail electric providers must stay connected to their customers with clear, frequent and effective communications and quality customer touch points, including billing and payment, customer service, corporate citizenship, enrollment and beyond, to achieve a premier provider position."

Satisfaction with the effectiveness of communications has risen to a high of 638 in 2013 from 2008. The frequency and recall of communications by electric retailers play an increasingly important role in customer satisfaction. Satisfaction is 717 among customers who recall communications from their retail electric provider (33%), compared with 666 among those who do not recall a communication (67%)--a dramatic difference of 51 points. The most frequently recalled methods of communicating are email (36%); direct mail (30%); and bill insert (20%).

Corporate citizenship and enrollment/renewal, two new factors in the 2013 study, debut as important drivers of customer satisfaction. Overall awareness of Texas REP corporate citizenship is low; however, customer satisfaction increases significantly when customers are aware of corporate citizenship efforts. For example, corporate citizenship satisfaction is 762 when customers are aware of their REP's impact on the environment, compared with 658 when they are not aware. The same general trend is observed when customers are aware vs. unaware of their REP's local donations and sponsorship (738 vs. 672, respectively) and volunteering/working in the community (763 vs. 670, respectively).

Satisfaction is highest in the enrollment/renewal factor (777). When customers are satisfied with their REP, they are more loyal to the brand, more likely to renew and more likely to recommend the REP to family and friends. Nearly two-thirds (60%) of new customers who enrolled for service within the past 12 months had service with another retail electricity provider. The main reason customers cite for selecting their provider is a lower price (61%).

Texas Residential Retail Electric Provider Customer Satisfaction Study Results

Champion Energy Services ranks highest among retail electric utility providers in Texas for a fourth consecutive year, with a score of 764. Champion Energy Services performs particularly well in price; billing and payment; enrollment/renewal; customer service; and communications. Following in the rankings are Green Mountain Energy (737) and Bounce Energy (736).

The 2013 Texas Residential Retail Electric Provider Customer Satisfaction Study is based on responses from 7,708 residential customers of electric retailers in Texas. The study was fielded between September 2012 and June 2013.

About J.D. Power

J.D. Power is a global marketing information services company providing performance improvement, social media and customer satisfaction insights and solutions. The company's quality and satisfaction measurements are based on responses from millions of consumers annually. Headquartered in Westlake Village, Calif., J.D. Power has offices in North America, Europe and Asia Pacific. For more information on car reviews and ratings, car insurance, health insurance, cell phone ratings, and more, please visit JDPower.com. J.D. Power is a business unit of McGraw-Hill Financial.

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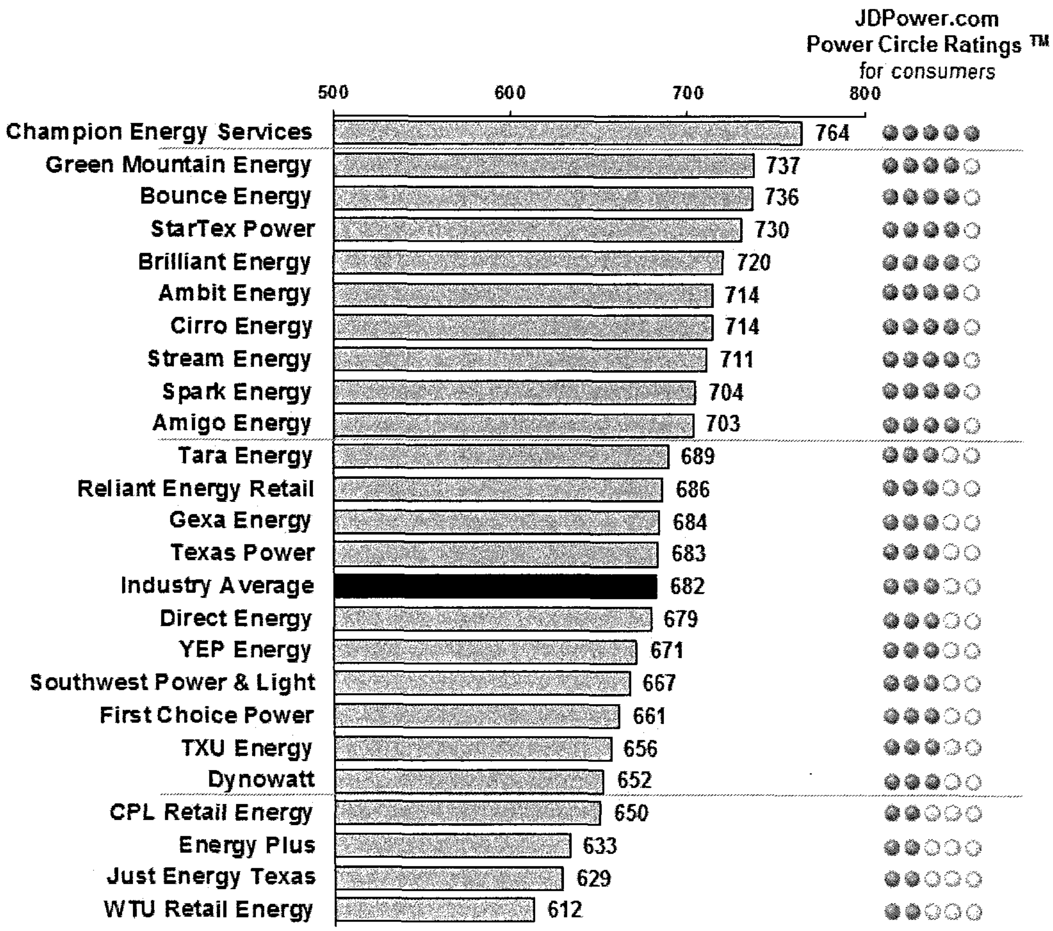
J.D. Power
2013 Texas Residential Retail Electric Provider Satisfaction Study℠

Customer Satisfaction Index Ranking
(Based on a 1,000-point scale)



Note: Included in the study, but not ranked due to small sample size are APG&E, Constellation, Gateway Energy Services, Mega Energy, Nueces Electric Cooperative, Potentia Energy, and Texpo Energy.

Source: J.D. Power 2013 Texas Residential Retail Electric Provider Customer Satisfaction Study℠

Power Circle Ratings Legend
- Among the best
- Better than most
- About average
- The rest

Charts and graphs extracted from this press release must be accompanied by a statement identifying J.D. Power as the publisher and the J.D. Power 2013 Texas Residential Retail Electric Provider Satisfaction Study℠ as the source. Rankings are based on numerical scores, and not necessarily on statistical significance. JDPower.com Power Circle Ratings™ are derived from consumer ratings in J.D. Power studies. For more information on Power Circle Ratings, visit jdpower.com/faqs. No advertising or other promotional use can be made of the information in this release or J.D. Power survey results without the express prior written consent of J.D. Power.

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2013 Canadian Customer Commitment Index Study
2013 Brazil Vehicle Ownership Satisfaction Study
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Attachment 5

TEXAS PUBLIC POLICY FOUNDATION
PolicyPerspective
January 2010
Center for Economic Freedom

Prices, Reliability, and Consumer Choice in the Texas Electricity Market

by Bill Peacock
Vice President of Research & Director of the Center for Economic Freedom

Key Points

- Federal government data make poor proxies for past and current prices in Texas' competitive area.
- Federal data show Texas above average nationally both pre- and post-restructuring; actual prices show Texas moving from above to below average.
- Average competitive prices (11.1 cents per kWh) today are 9.46% below average 2001 regulated prices; the lowest average price (8.52) is 30.51% lower.
- Most New Yorkers (19.17), Californians (14.08), and Floridians (12.31) pay higher prices than Texans; Texas prices are competitive with surrounding states.
- Texans can choose from 138 residential plans offered by 29 providers.
- Renewable energy subsidies and energy efficiency mandates could add $2.65 *billion* annually to electricity bills by 2020.

PP05-2010

It has been fourteen years since Texas began restructuring its electricity market to foster wholesale competition, eight years since competition was introduced into the retail market, and three years since retail electricity price controls were eliminated. The restructuring continues, with the next major step of implementing a nodal transmission market.

That Texas is still moving forward make us unique among the 50 states. Lynne Kiesling and Andrew Kleit put the Texas experience in context:

> Since the California escapade [of 2000-1], several states have moved backward with electricity restructuring, and no state has moved forward. No state, that is, except Texas. ... Texas, alone among the U.S. states, [has] moved forward into a truly restructured and competitive electricity era.[1]

While restructuring has not always gone smoothly and has generated much debate, the problems—high natural gas prices, special interests, and intense media scrutiny—that in other states stopped restructuring in its tracks did not stop Texas.

Why this is could be debated, though three key elements stand out: leadership by policymakers, a marketplace designed to let market participants compete, and the Price to Beat. However we got here, though, Texas is now moving forward into the frontier of electricity markets with very little company.

Yet not everyone believes this is the journey Texas should be taking. As one critic says, "The ultimate problem [with deregulation] is that the market is designed to maximize profits for the power companies, and it's costing consumers more money."[2]

Of course, the Texas electricity market is not deregulated. Even within the Electric Reliability Council of Texas (ERCOT) competitive region there are extensive regulations, including wholesale price caps and traditional rate regulation on transmission and distribution utilities.

Still, the question remains, are Texans better or worse off today than before restructuring?

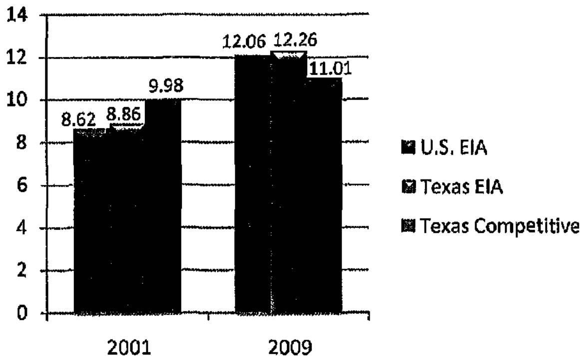
Three factors that need to be examined to answer this question: prices, reliability, and consumer choice. This paper examines all three. It will also examine the growing trend of forcing consumers to bear significant costs through added fees and taxes on their electricity bills.

Electricity Prices

U.S. Energy Information Administration (EIA) price data are commonly used to measure the effectiveness of the restructuring of Texas' electricity market. However, an examination of actual residential market prices shows that the EIA data make poor proxies for prices in Texas' competitive markets. Because of this, relying on EIA price data significantly understates the drop in Texas residential prices under competition; prices are generally lower today than in 2001, the last year of regulated prices in ERCOT.

continued on next page

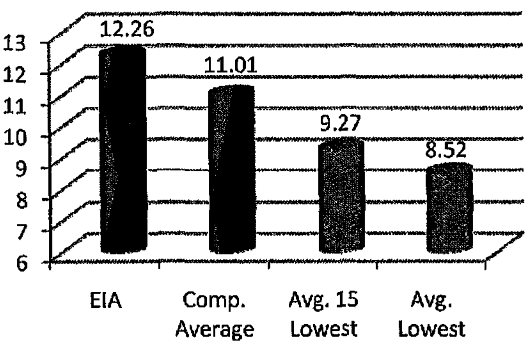
Texas Residential Electricity per kWh Prices Pre- and Post-Restructuring, Unadjusted for Inflation



Source: Energy Information Administration and Powertochoose.com

EIA data do not accurately portray past and current prices in Texas' competitive area. Though EIA data show Texas' 2001 prices slightly above the national average, regulated prices in ERCOT's competitive regions were significantly higher. For 2009, EIA data still show Texas above average nationally, but average competitive prices are below average. What accounts for the differences? First, EIA data include non-competitive prices charged by non-ERCOT utilities, electric cooperatives, and municipally-owned utilities. Second, cooperative and municipal prices have increased relative to prices in competitive areas. Third, the EIA can no longer rely on getting comprehensive price data from regulators in Texas as it can in most other states.

Comparison of Reported vs. Actual Texas Residential Electricity Prices per kWh, 2009



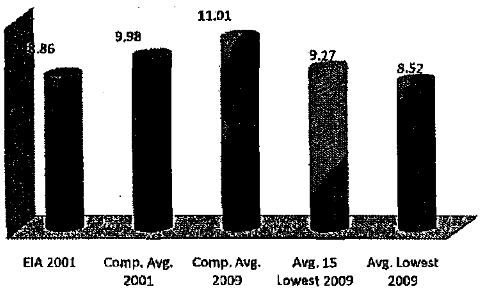
Source: Energy Information Administration and Powertochoose.com

Even so, EIA data provide a fairly positive review of electricity restructuring in Texas. But competitive price data paints an even better picture. For instance, 2001 regulated rates in Texas' competitive areas (9.98 cents per kWh) averaged 15.8 percent above the national average. Today, however, the average competitive price (11.01 cents per kWh) is 8.71 per cent *below* the national average, while the average of the 15 lowest offers (9.27 cent per kWh) is 23.13 percent below the national average.*

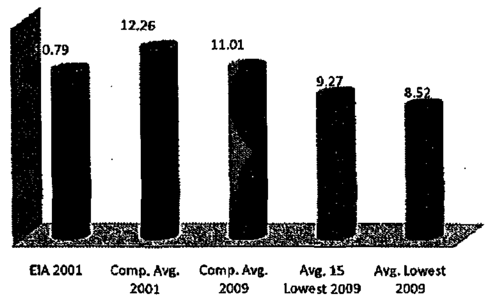
More good news for Texas consumers is that competitive prices have fallen not only relative to national prices, but are on average lower in real terms than regulated prices in Texas in 2001 (see charts below). Adjusted for inflation, the average competitive price today is 9.46 percent below the average 2001 regulated price; the average of the 15 lowest prices is 24.39 percent lower; and the lowest average price is 30.5 percent lower. Even without adjusting for inflation, however, most Texans can easily buy electricity today below 2001 regulated prices.

Texas Residential Electricity Prices per kWh

Unadjusted for Inflation



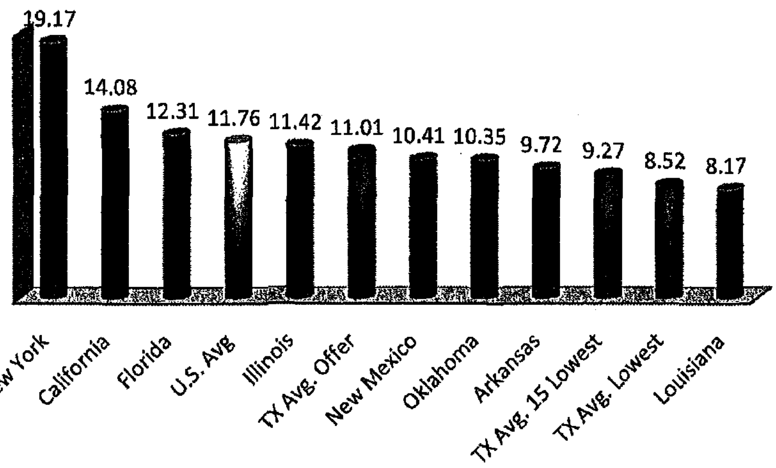
Adjusted for Inflation, 2009 dollars



Source: Energy Information Administration and Powertochoose.com

*Texas competitive prices are as of December 2009. EIA prices are as of October 2009.

Texas vs. U.S. Residential Electricity Prices per kWh, 2009

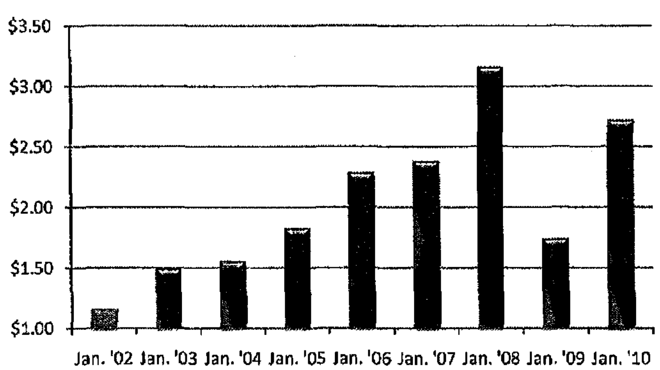


Source: Energy Information Administration and Powertochoose.com

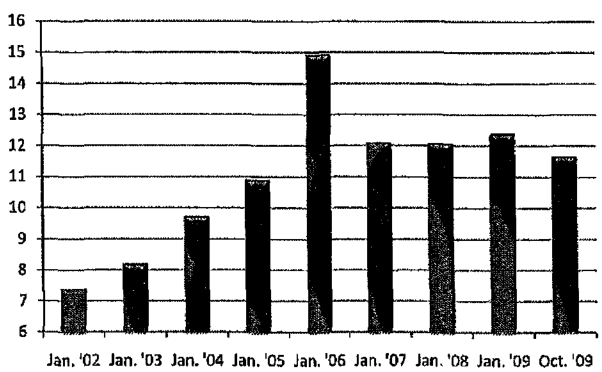
Additionally, actual Texas prices fare quite well against our neighboring states' prices, despite recent reports.[3] The average price of the 15 lowest offers in Texas is lower than the average price in New Mexico, Oklahoma, and Arkansas, and the average lowest price is close to the average price even in low-cost Louisiana. Further, Texas prices are lower—significantly in many cases—than the average price in the other four of the five largest states. Perhaps the lower price of electricity in Texas is one reason it has recently moved past New York and California as the home to the most Fortune 500 companies.

While there are several ways to look at the data, it is clear that electricity prices have decreased in Texas since competition was introduced. The decline is remarkable when compared to increases in other consumer energy prices such as gasoline and natural gas—especially since natural gas is often claimed to drive electricity prices in Texas.

Retail Gasoline Prices, 2002-10



Residential Natural Gas Prices, 2002-09



Source: Energy Information Administration

Reliability

Earlier this month, Florida experienced unseasonably cold weather, with temperatures dipping into the teens in places. This resulted in a record-setting demand for electricity that sent the Florida system into shock. Customers in various areas throughout the state struggled with power outages lasting from a few hours to most of the day.

To cope with the ongoing cold, Florida Power & Light Co. implemented its voluntary load-management program for some customers on Florida's east coast, meaning many customers had to go without electricity for a time. For instance, classes scheduled to start before 11 a.m. at all Brevard Community College campuses and University of Central Florida satellite campuses in Cocoa and Palm Bay were canceled. Consumers were also asked to set their thermostats at 68 degrees and check their filters to increase energy efficiency.[4]

Venezuela has had even more problems. It experienced rolling blackouts throughout the county in January. Venezuelan President Hugo Chavez said he is "going to continue to apply a rigorous energy saving plan" to address the problem.[5] Similarly, New York and California have experienced significant power shortages within the last decade.

Texans have experienced only two problems with reliability in recent years. In 2006, an unexpected April heat wave caught Texas with 14,000 megawatts offline for scheduled maintenance. Peak demand reached an all-time April high of 51,714 megawatts—2,500 megawatts higher than forecasted. Overall capacity, however, was not a problem. Additional units were brought back online and service was restored quickly. The other problem occurred on February 26, 2008, when the wind in West Texas suddenly stopped blowing. Over the 40-minute period preceding the start of load curtailment, wind generation declined by 80 megawatts relative to its schedule. This led to minimal disruptions and, in any event, was caused not by capacity issues but by the unreliability of wind.

The reliability of the Texas system is due in large part to Texas' ample reserve margins. ERCOT sets a target of a 12.5 percent reserve margin over expected summer peak capacity. Last summer, Texas had a reserve margin of about 16.8 percent. ERCOT projects that Texas will have reserve margins of 21.8 percent, 19.9 percent, and 18.1 percent over the next three years, respectively.

Texas' impressive reserve margins—and thus increased reliability—are a direct result of its competitive energy-only market.* One indication of this is that Texas' reserve margins are almost always higher than originally forecasted. For instance, the table below shows that 2009 reserves were forecasted in 2007 to be only 10.1 percent, well below the actual figure of 16.8 percent. It is only as the actual date gets closer that the forecast approaches the actual target. The same phenomenon is holding true for 2010 and 2011.

ERCOT Reserve Margin Projections

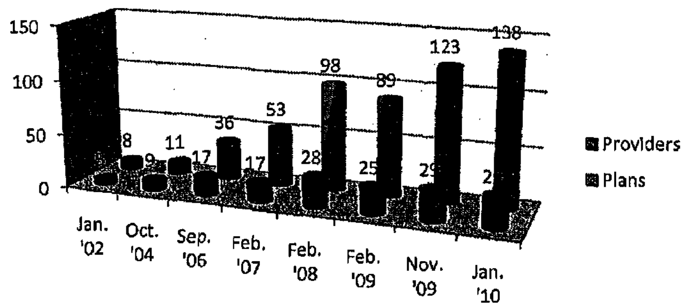
	2009	2010	2011	2012	2013	2014	2015
May 2007	10.1%	8.3%	6.7%	5.9%	n/a	n/a	n/a
Dec. 2007	12.1%	14.0%	11.2%	10.5%	8.2%	n/a	n/a
May 2008	16.5%	17.3%	15.0%	14.5%	12.3%	n/a	n/a
Dec. 2008	15.8%	21.2%	18.7%	17.8%	17.9%	15.8%	n/a
May 2009	16.8%	20.1%	18.8%	17.0%	16.3%	13.9%	n/a
Dec. 2009	n/a	21.8%	19.9%	18.1%	14.7%	12.3%	10.2%

Source: 2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region, ERCOT

*Texas' previous rate of return market was one where regulators determined the desired generation for the market, approved the construction of new generation, and determined what consumers would pay for that generation by providing the utility with a guaranteed rate of return. In other words, most of the risk for the need and cost of the generation was borne by ratepayers. Texas operates an energy-only market today. Texas can do this where other states can't because it relies on price signals to tell investors when new generation is needed, and only Texas has sufficient competition to let an energy-only market operate efficiently. Though the electricity market structure still does not transmit signals perfectly, the energy-only market has operated well enough to provide Texas with ample reserve margins while shifting the risks of over-construction from consumers to investors.

What explains the ample reserve margins and the poor initial projections? A big part is Texas' restructured energy-only market. Unlike Texas' previous market structure where generators had to get permission to build new generation facilities, in Texas, generators build facilities when they believe they can turn a profit. The lack of state pre-approval means that ERCOT may not know what facilities will be online as far out as they would in a more regulated market. The profit incentive has led to an investment of over $25 billion in 39,000 MW of new generation since 1996[6] and ensured that investors—not consumers—take the risk that all of this electricity can be sold. In rate-based markets, the cost of the new generation is added into the rate base and paid for by consumers whether they need it or not.

Retail Electric Providers and Plans



Source: Powertochoose.com

Consumer Choice

The final indicator of whether restructuring is working is the consumer choice in the Texas electricity market, which is a good way to determine competitiveness in the market. The investment in generation seen in the previous section shows the competitiveness of the wholesale market. However, competition is also strong in the retail market. The average Texan in ERCOT can choose from 138 different plans offered by 29 different providers. This is up from five providers offering eight plans in 2002.

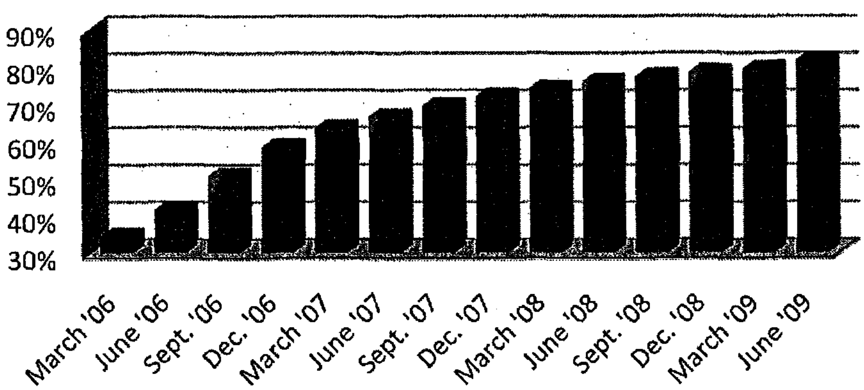
Additionally, almost 82 percent of consumers have actively chosen competitive rate plans, while the other 18 percent have benefitted from competition through lowered rates on old plans or getting competitive rates through move-ins. Almost everyone is participating in Texas' highly competitive electricity market.

Increasing Consumer Costs

One thing restructuring hasn't done is to decrease the tendency of government to place charges on electric bills that make electricity more expensive for consumers.

Historically, state and local governments have used regulated monopolies such as electricity, telecommunications, and natural gas companies as revenue collectors. Electricity franchise fees are one example, which today generate over $250 million annually for local governments.[7] While these fees began long before restructuring, several new charges have been added since then.

Consumer Choice and Participation



Source: Bret J. Slocum, "Second Quarter Data Concerning Customers Exercising Choice," letter to the Public Utility Commission of Texas (Aug. 5, 2009)

Renewable energy subsidies and energy efficiency mandates now cost consumers far more than franchise fees. For instance, subsidies for Texas wind energy through the federal Production Tax Credit should cost taxpayers about $300 million in 2010—though this is a tax subsidy, not an add-on to the electric bill.[8] The cost of wind Renewable Energy Credits—about $41 million this year—are passed on to consumers through the cost of electricity.[9] Finally, Competitive Renewable Energy Zone transmission lines—being built to transmit electricity from wind in West Texas—will add as much as $1.3 billion annually to electricity bills once the lines have been completed.[10] The extra annual cost to consumers and taxpayers for wind energy should reach $2 billion by 2020.[11]

Last session multiple bills were filed to further increase these costs. The bills focused on increased subsidies for renewable energy—especially solar and biomass—and for energy efficiency. None of the legislation passed. But it is certain attempts will be made to pass them again in 2011.

The costs of the bills varied. Though the bills that had the most support cost less, proposed solar subsidies ran as high as $220 million annually, while the price tag for energy efficiency mandates reached up to $426 million per year.[12]

Add all these up, and the annual cost for these energy subsidies could run as high as $3 billion per year, most of it being paid for by Texas electricity customers.

Conclusion

The evidence clearly points to the conclusion that Texas' restructuring of its electricity market has led to lower consumer prices, greater reliability, and highly competitive markets. It is worth noting, however, that the critics of restructuring—who oppose it because they (mistakenly) claim it has increased prices—are usually the same ones who seek to force higher prices on consumers through renewable energy subsidies and energy efficiency mandates.

Because of concern over high electricity prices in 2007, the Texas Legislature came close—only a parliamentary technicality stopped it—to significantly increasing regulations on the market. Additionally, the Legislature has created the System Benefit Fund to help low-income Texans pay their electricity bills in the restructured market. Yet the same Legislature that wants low prices continues to increase electricity prices through energy subsidies and mandates. It is paradoxical that these higher costs are being made more palatable to the public by the lower electricity prices produced by restructuring.

Markets don't guarantee the lowest possible prices, but they do guarantee the best possible prices based on a customer's preference. Customers often prefer reliability, customer service, lack of volatility, and brands over the lowest possible price. Yet today, it appears that Texas consumers are getting all of those things and low prices as well. Only the government is keeping prices from getting even lower. ✯

Endnotes

[1] Lynne Kiesling & Andrew Kleit, *Electricity Restructuring: The Texas Story*, AEI Press (Dec. 2009), p. 5.

[2] Tom "Smitty" Smith, "Texas' retail electric rates significantly higher than neighboring states," *Fort Worth Star-Telegram* (Dec. 12, 2009).

[3] Ibid.

[4] Orlando Sentinel, "Voluntary power reductions begin as demand surges" (Jan. 11, 2010).

[5] RTT News, "Chavez Sacks Power Minister For Wrongly Implementing Rolling Blackouts" (Jan. 14, 2010).

[6] ERCOT, ERCOT Quick Facts, 2009.

[7] Calculations of the author based on a review of city budgets.

[8] Bill Peacock, *The True Cost of Wind Energy*, Texas Public Policy Foundation (Oct. 2008).

[9] Ibid.

[10] Ibid.

[11] Ibid.

[12] Bill Peacock, "Texas' New Energy Taxes," Texas Public Policy Foundation (May 2009).

About the Author

Bill Peacock is the vice president of research and director of the Texas Public Policy Foundation's Center for Economic Freedom. He has been with the Foundation since February 2005.

Bill has extensive experience in Texas government and policy on a variety of issues including, economic and regulatory policy, natural resources, public finance, and public education. His work has focused on identifying and reducing the harmful effects of regulations on the economy, businesses, and consumers.

Prior to joining the Foundation, Bill served as the Deputy Commissioner for Coastal Resources for Commissioner Jerry Patterson at the Texas General Land Office. Before he worked at the GLO, Bill was a legislative and media consultant. He has also served as the Deputy Assistant Commissioner for Intergovernmental Affairs for then-Commissioner Rick Perry at the Texas Department of Agriculture and as a legislative aide to then-State Rep. John Culberson.

Bill has a B.A. in History from the University of Northern Colorado and a M.B.A. with an emphasis in public finance from the University of Houston.

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The work of the Foundation is primarily conducted by staff analysts under the auspices of issue-based policy centers. Their work is supplemented by academics from across Texas and the nation.

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The public is demanding a different direction for their government, and the Texas Public Policy Foundation is providing the ideas that enable policymakers to chart that new course.

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Attachment 6

Article posted: 12/27/2012 5:00 AM

$31 billion in benefits, and counting

By

Imagine a public policy in Illinois that was thoughtfully developed, carefully nurtured and professionally adjusted as needed and has delivered $31 billion in benefits to the public.

Stumped?

Answer: our state's transition to competitive electricity markets.

Dec. 16 marked the 15th anniversary of Gov. Jim Edgar's signing of Illinois' 1997 electric industry restructuring legislation. After months of review and debate, the General Assembly passed the bill with near-unanimous votes, making Illinois a pioneer in reforming a century-old business model. Customers could choose their own electricity suppliers while continuing to rely on a regulated utility to deliver the energy over its distribution wires.

Chicago-area ComEd and downstate Ameren either sold some of their power plants or spun others off to affiliated companies focused solely on generating electricity to be marketed in a competitive market. Utilities and the regulators could concentrate on the singular task of reliably delivering energy over the distribution network and assuring equal access by buyers and sellers to the grid.

The Illinois Commerce Commission started the process in the mid-1980s with policy papers urging reliance on competition in telecommunications, natural gas and electricity as a better regulator of prices than lengthy administrative proceedings. The General Assembly passed a modernized telecommunications law in 1985 that helped accelerate the dramatic changes in telecommunications now a part of our everyday lives.

Customer choice in electricity supply is now the rule in over a dozen states accounting for more than 40 percent of all U.S. electricity consumption. Some states, such as California and Michigan, mismanaged their transitions and are facing rapidly rising rates. Illinois stayed on course as did such foreign countries as the UK, Australia, New Zealand some Canadian provinces and much of Europe.

Today, some 75 licensed alternative retail electricity suppliers (ARES) supply about two-thirds of all the electricity consumed in Illinois. The latest vivid illustration of customer choice came with this year's elections in which voters in more than 450 communities, including Chicago, have authorized municipal aggregation programs. "Muni-agg" allows local governments to arrange competitive electricity supply contracts for residential and small business customers in their jurisdictions. Customers can opt out in favor of a supplier of their own choosing.

In the decade prior to implementation of customer choice in 1999, electricity prices paid by Illinois consumers averaged 12 percent above the national average. Since then, Illinois prices have averaged 7 percent below the national norm.

This nearly 20 percent swing in Illinois' price position has been worth more than $31 billion in electricity cost savings for businesses, government, schools, hospitals and households. Data from the U.S. Energy Information Administration show that since 1997, while electricity prices nationally have risen an average of 46 percent, Illinois electricity rates have risen 17 percent, about one-third the national pace and well below the rate of inflation.

Greg Baise, president of the Illinois Manufacturers Association, has often said that Illinois' electricity choice policy has been the most successful economic development program in Illinois in many decades.

Despite a decade and a half of change, however, our mental map of the electricity business remains rooted in the old paradigm of the monopoly utility. For example, recent new stories about muni-agg report that customers are "leaving ComEd." Not so.

While, most residential and small business customers receive a monthly bill with ComEd's name on it, the electrical energy actually comes from a state government entity called the Illinois Power Agency. ComEd does not own or operate power plants. The IPA acquires power supplies through a competitive procurement process. ComEd only delivers the power and sends a bill for the energy cost, without a markup.

In the 1980s and beyond, billboards at the Wisconsin border invited businesses to cross the state line to get lower electricity rates. In 1997, average Illinois electricity rates were 47 percent higher than those in Wisconsin. The situation is now the reverse. Average electricity prices in the Land of Lincoln are 22 percent lower than Wisconsin's.

It seems that in the Dairy State, which has declined to adopt electricity competition, it's the consumers who are being milked.

Maybe it's time that Illinoisans took some pride in a public policy achievement that has become a model for much of the industrialized world.

Ÿ Vince Persico, a Republican, and Philip Novak, a Democrat, were members of the Illinois House of Representatives who co-sponsored electricity customer choice law in 1997.

Attachment 6

Article posted: 12/27/2012 5:00 AM

$31 billion in benefits, and counting

By

Imagine a public policy in Illinois that was thoughtfully developed, carefully nurtured and professionally adjusted as needed and has delivered $31 billion in benefits to the public.

Stumped?

Answer: our state's transition to competitive electricity markets.

Dec. 16 marked the 15th anniversary of Gov. Jim Edgar's signing of Illinois' 1997 electric industry restructuring legislation. After months of review and debate, the General Assembly passed the bill with near-unanimous votes, making Illinois a pioneer in reforming a century-old business model. Customers could choose their own electricity suppliers while continuing to rely on a regulated utility to deliver the energy over its distribution wires.

Chicago-area ComEd and downstate Ameren either sold some of their power plants or spun others off to affiliated companies focused solely on generating electricity to be marketed in a competitive market. Utilities and the regulators could concentrate on the singular task of reliably delivering energy over the distribution network and assuring equal access by buyers and sellers to the grid.

The Illinois Commerce Commission started the process in the mid-1980s with policy papers urging reliance on competition in telecommunications, natural gas and electricity as a better regulator of prices than lengthy administrative proceedings. The General Assembly passed a modernized telecommunications law in 1985 that helped accelerate the dramatic changes in telecommunications now a part of our everyday lives.

Customer choice in electricity supply is now the rule in over a dozen states accounting for more than 40 percent of all U.S. electricity consumption. Some states, such as California and Michigan, mismanaged their transitions and are facing rapidly rising rates. Illinois stayed on course as did such foreign countries as the UK, Australia, New Zealand some Canadian provinces and much of Europe.

Today, some 75 licensed alternative retail electricity suppliers (ARES) supply about two-thirds of all the electricity consumed in Illinois. The latest vivid illustration of customer choice came with this year's elections in which voters in more than 450 communities, including Chicago, have authorized municipal aggregation programs. "Muni-agg" allows local governments to arrange competitive electricity supply contracts for residential and small business customers in their jurisdictions. Customers can opt out in favor of a supplier of their own choosing.

In the decade prior to implementation of customer choice in 1999, electricity prices paid by Illinois consumers averaged 12 percent above the national average. Since then, Illinois prices have averaged 7 percent below the national norm.

This nearly 20 percent swing in Illinois' price position has been worth more than $31 billion in electricity cost savings for businesses, government, schools, hospitals and households. Data from the U.S. Energy Information Administration show that since 1997, while electricity prices nationally have risen an average of 46 percent, Illinois electricity rates have risen 17 percent, about one-third the national pace and well below the rate of inflation.

Greg Baise, president of the Illinois Manufacturers Association, has often said that Illinois' electricity choice policy has been the most successful economic development program in Illinois in many decades.

Despite a decade and a half of change, however, our mental map of the electricity business remains rooted in the old paradigm of the monopoly utility. For example, recent new stories about muni-agg report that customers are "leaving ComEd." Not so.

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Attachment 7

OFFICE OF RETAIL MARKET DEVELOPMENT
ILLINOIS COMMERCE COMMISSION

2013 ANNUAL REPORT

Submitted Pursuant to Section 20-110 of the Illinois Public Utilities Act

June 2013

Printed by authority of the State of Illinois
35c. - June 2013 - #709

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

June 30, 2013

The Honorable Pat Quinn
Governor

The Honorable Members of the Illinois General Assembly

The Honorable Members of the Illinois Commerce Commission

Please find enclosed the ICC's Office of Retail Market Development's annual report. This report is submitted in compliance with Section 20-110 of the "Retail Electric Competition Act of 2006" [220 ILCS 5/20-110]. Section 20-110 requires the Director of the Office of Retail Market Development to annually report specific accomplishments in promoting retail electric competition.

Sincerely,

Torsten Clausen

Torsten Clausen
Director, Office of Retail Market Development

160 North LaSalle, Suite C-800, Chicago, Illinois 60601 (312) 814-1629

Annual Report to the General Assembly, the Governor, and the Illinois Commerce Commission

Submitted pursuant to Section 20-110 of the Illinois Public Utilities Act

Office of Retail Market Development

Illinois Commerce Commission

June 2013

Executive Summary

- Illinois now has 87 alternative retail electric suppliers ("ARES") that have obtained ICC certification to serve retail customers, up from 70 ARES at the same time last year (see page 3 of the report).

- The number of licensed Agents, Brokers and Consultants (ABCs) – 263 as of June 2012 – is almost double the number from two years ago (see page 5).

- As of May 31, 2013, ARES provide nearly 80% of the total electric usage in ComEd and Ameren Illinois service areas, up from 60% at the same time last year (see pages 4-9).
  - ♦ Nearly 81% of the total electric usage of ComEd's customers was provided by ARES, up from 64% last year.
  - ♦ 68% of the total electric usage in the Ameren Illinois Rate Zone I (formerly AmerenCIPS) was provided by an ARES, up from 60% last year.
  - ♦ Nearly 82% of the total electric usage of Ameren Illinois Rate Zone II (formerly Ameren CILCO) customers was provided by ARES, up from 65% last year.
  - ♦ Nearly 80% of the total electric usage of Ameren Illinois Rate Zone III (formerly Ameren IP) customers was provided by ARES, up from 68% last year.

- Switching activity for the residential class increased dramatically in the last year (see pages 14-28).
  - ♦ As of May 31, 2013, nearly three million residential customers across the state had selected to receive their power from an ARES, up from less than 500,000 in May 2012.
  - ♦ Nearly 68% of ComEd's residential customers are receiving service from a supplier.
  - ♦ The residential switching pace increased from 1,300 customers per day between May 2011 and May 2012 to about 6,500 customers per day from May 2012 to May 2013.
  - ♦ Total estimated annual savings from June 2012 through May 2013 by residential ARES customers in ComEd's service territory is an impressive $268 million dollars or 2.4 cents per kWh, compared to $24 million or 1.4 cents per kWh for the prior year.
  - ♦ In May 2013, 57 certified ARES served residential customers in the ComEd service territory, compared to 40 in May 2012. Thirty-three certified ARES served residential customers in the Ameren Illinois service territory, up from 26 in May 2012.

- As of April 2013, 28 ARES were posting 63 different residential offers on PluginIllinois.org for the ComEd service territory. Ten ARES were posting 20 different offers in the Ameren Illinois service territories, up from six ARES and 11 offers in May 2012.
- Of the residential offers posted on PluginIllinois.org for ComEd customers, 73% were fixed offers and 17% were variable.

- Goverment Aggregation: The residential switching numbers and market concentration levels changed markedly from last year due to municipal aggregation (see pages 15, 22 and 33).
    - In May 2012, 17% of residential ARES customers were part of a government aggregation program, and in May 2013, almost 78% of ARES residential customers take part in a government aggregation program.
    - A total of 677 communities passed an opt-out aggregation referendum to date, with 411 of those taking place in the last 12 months.
    - The ComEd residential market, based on HHI values, is "moderately concentrated", with 69% of the market going to the three largest suppliers in May 2013, compared to 44% in May 2012.

- Significant growth in competitive switching has been seen in the small commercial customer class (0-100kW) in both the ComEd and Ameren Illinois service territories in the last 12 months (see pages 5-9).
    - As of May 31, 2013 ARES provide about 63% of the electric usage of ComEd's smallest commercial customers (0-100kW), up from 52% a year ago.
    - ARES-provided usage accounts for 61% of the electric usage of Ameren Illinois Rate Zone I smallest commercial customers (0-100kW), up from 55% a year ago.
    - ARES provide nearly 65% of the electric usage of Ameren Illinois Rate Zone II smallest commercial customers (0-100kW), up from 55% a year ago.
    - As of May 31, 2013 ARES-provided usage accounts for about 63% of the electric usage of Ameren Illinois Rate Zone III smallest commercial customers (0-100kW), up from nearly 56% a year ago.

I. Introduction

Section 20-102 of the Retail Electric Competition Act of 2006 ("Retail Competition Act") states that

> "a competitive wholesale electricity market alone will not deliver the full benefits of competition to Illinois consumers. For Illinois consumers to receive products, prices and terms tailored to meet their needs, a competitive wholesale electricity market must be closely linked to a competitive retail electric market. To date, as a result of the Electric Service Customer Choice and Rate Relief Law of 1997, thousands of large Illinois commercial and industrial consumers have experienced the benefits of a competitive retail electricity market. Alternative electric retail suppliers actively compete to supply electricity to large Illinois commercial and industrial consumers with attractive prices, terms, and conditions.
>
> A competitive retail electric market does not yet exist for residential and small commercial consumers. As a result, millions of residential and small commercial consumers in Illinois are faced with escalating heating and power bills and are unable to shop for alternatives to the rates demanded by the State's incumbent electric utilities. The General Assembly reiterates its findings from the Electric Service Customer Choice and Rate Relief Law of 1997 that the Illinois Commerce Commission should promote the development of an effectively competitive retail electricity market that operates efficiently and benefits all Illinois consumers."

To further the goal of developing an effectively competitive retail electricity market, the Retail Competition Act created the Office of Retail Market Development ("ORMD") within the Illinois Commerce Commission ("ICC"). Section 20-110 of the Retail Competition Act provides that on or before June 30 of each year, the Director of the ORMD submit a report to the Commission, the General Assembly, and the Governor, that details specific accomplishments achieved by the Office in the prior 12 months in promoting retail electric competition and that suggests administrative and legislative action necessary to promote further improvements in retail electric competition.

II. Recent competitive activity

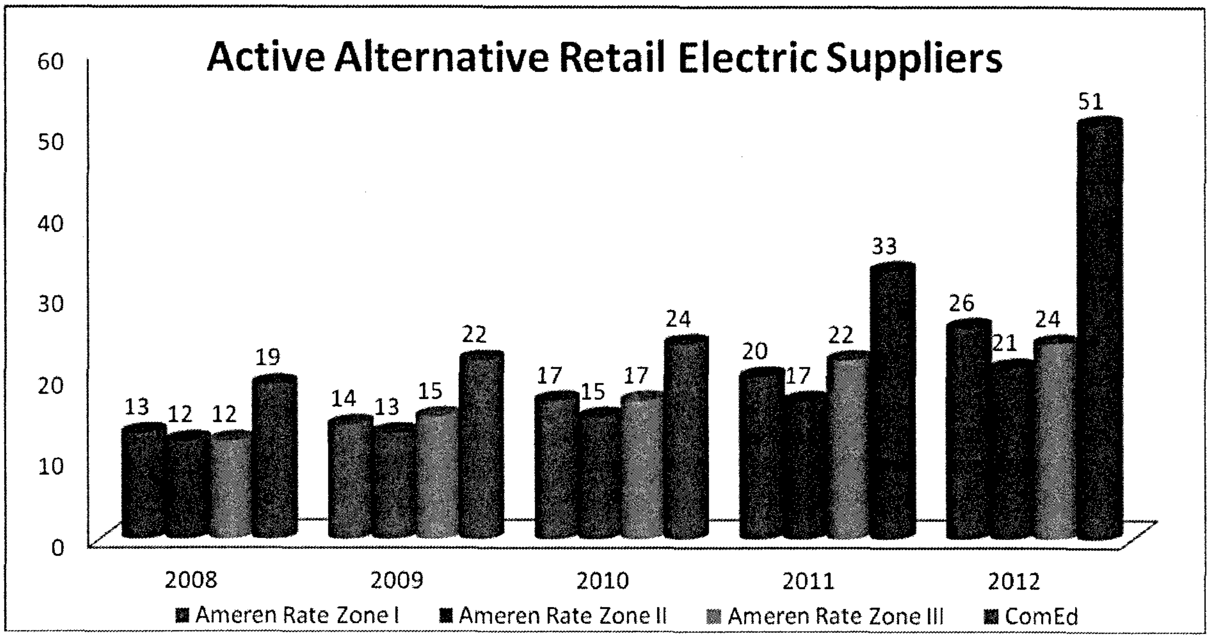
A. Number of certified and registered suppliers

Statewide, there are currently 87 alternative retail electricity suppliers ("ARES") that have obtained ICC certification pursuant to Section 16-115[1]. This is up from 70 suppliers at the same time last year. Fifty-seven ARES have obtained certification to serve residential and small commercial customers, which is up from 40 as of last year. Aside from receiving a certificate from the Commission, suppliers must also register with the electric utility and complete certain technical testing before they can start offering retail electric service in Illinois. Thirty-three suppliers have completed the registration process with Ameren Illinois, compared to 26 at the same time last year. Thirty-two of those suppliers were actively selling electricity in the territory as of December 2012, up from 24 as of December 2011. In Commonwealth Edison's ("ComEd's") territory, sixty suppliers have completed the registration process, up from 44 suppliers last year. Fifty-one of those suppliers were actively selling electricity as of December 2012, compared to 35 as of December 2011. Four of the active suppliers are either electric utilities or affiliates of electric or natural gas utilities.

The following shows the number of active ARES from 2008 to the end of 2012 by utility service territory:[2]

[1] Twelve of the 87 suppliers are certified to serve only themselves or their affiliates.

2 In order to maintain consistency with the reporting of previous years, the graph includes ARES providing power to themselves or their subsidiaries for the Ameren Illinois territories. Also, several suppliers operate in more than one utility service territory.



B. Customer switching to alternative electric suppliers

For the past few years, more than half of the total electric consumption of ComEd's and Ameren Illinois's customers had been provided by alternative retail electric suppliers. Last year marked the first time that more than 60% of the total electric usage of ComEd customers as well as the customers of all three Ameren Illinois rate zones had been provided by retail electric suppliers. This year, as of May 31, almost 80% of the total usage in ComEd and Ameren Illinois' service areas has been provided by competitive retail electric providers. Looking specifically at ComEd, February 2008 marked the first time more than 50% of the total electric usage was provided by competitive suppliers and October 2011 was the month that the number had crossed the 60% mark for the first time. While it took more than three and a half years from crossing the 50% mark to crossing the 60% mark, it took only a year (from October 2011 to October 2012) from crossing the 60% mark to topping the 70% mark. Even more remarkable, just seven months later, in April 2013, 80% of the total electric usage in ComEd's territory was provided by retail electric suppliers. Also worth pointing out is that the amount of ARES-provided electric usage to the 0-100 kW customer class has crossed the 60% mark in both ComEd and Ameren Illinois' territories for the first time this year.

One additional indicator of competitive activity is the steadily rising number of Agents, Brokers, and Consultants ("ABCs") seeking a license pursuant to Section 16-115C of the Public Utilities Act ("PUA"). There are currently 263 licensed ABCs, which is almost double the number from just two years ago.

The following provides detailed non-residential usage information for the four utility service areas.

1. ComEd

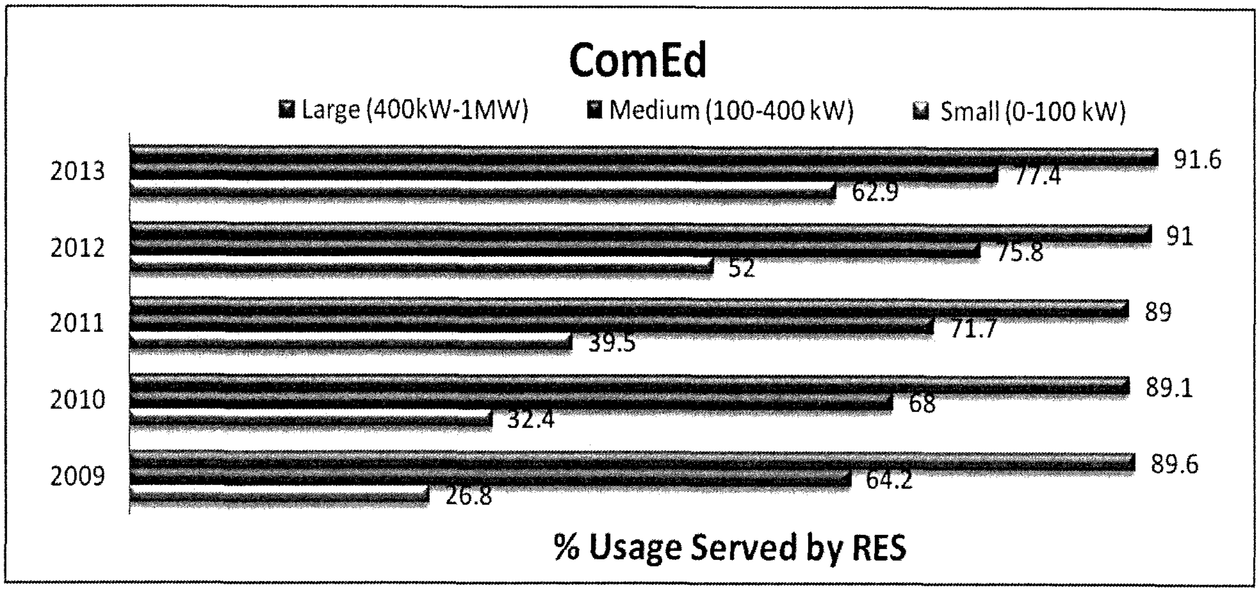
As of May 31, 2013, nearly 81% of the total electric usage of ComEd's customers was provided by alternative retail electric suppliers (up from 64% a year ago). Breaking it down further, about 63% of the electric usage of ComEd's small commercial customers[3] (up from about 52% a year ago) and 77% of its medium commercial and industrial customers[4] (up from about 76%) was provided by ARES. For large customers[5] it was nearly 92% (up from 91% last year), and 96% of customers with a demand of over 1MW received service from an ARES (the same as last year). Together, nearly 88% (up from 83%) of all non-residential load was provided by alternative retail electric suppliers as of May 31, 2013. The following shows the electric usage provided by ARES for the various commercial and industrial customer classes for the past four years[6].

[3] Non-residential customers with demand up to 100kW.

[4] Non-residential customers with demand between 100kW and 400kW.

[5] Non-residential customers with demand between 400kW and 1MW.

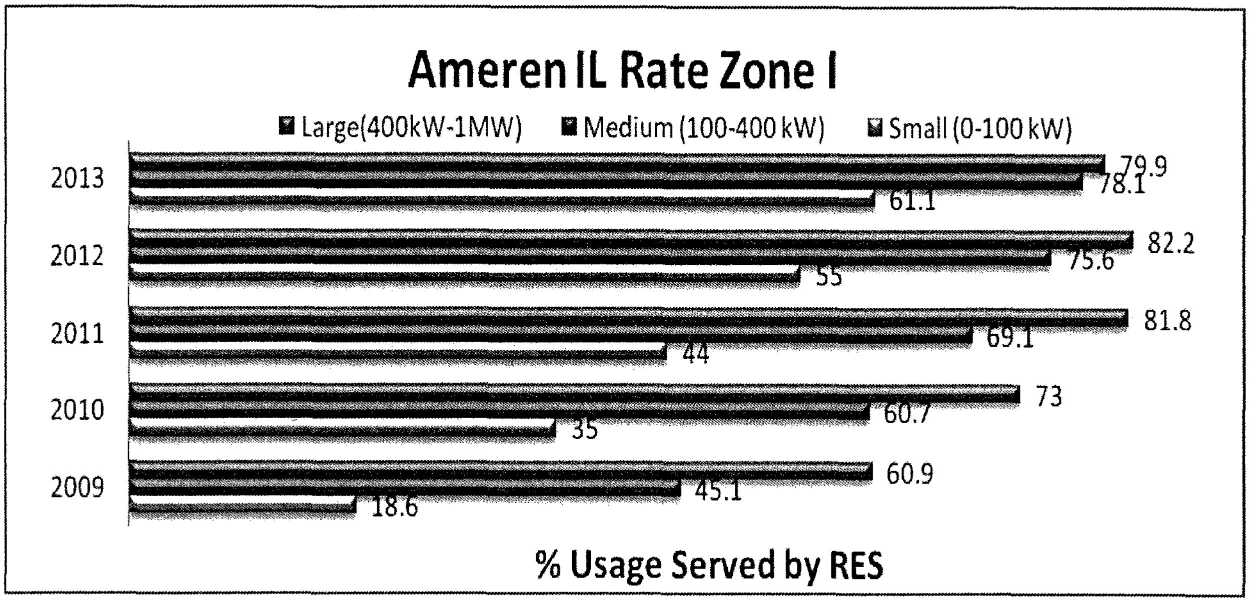
[6] Data as of May 31 of each year.



2. Ameren Illinois Rate Zone I (formerly AmerenCIPS)

As of May 31, 2013, 68% of the total electric usage of Rate Zone I customers was provided by alternative retail electric suppliers (up from 60% a year ago). Sixty-one percent of the electric usage of small commercial customers in Rate Zone I (up from 55% a year ago) and approximately 78% of electric usage of its medium commercial and industrial customers (up from 76%) was provided by ARES. For large customers it was 80% (down from 82% last year), and for customers with a demand of over 1MW, 80% of the usage was served by alternative electric suppliers (unchanged from last year). Together, 76% of all non-residential load was provided by alternative retail electric suppliers as of May 31, 2013 which remains unchanged from a year ago). The following shows the electric usage provided by ARES for the various commercial and industrial customer classes for the past four years[7].

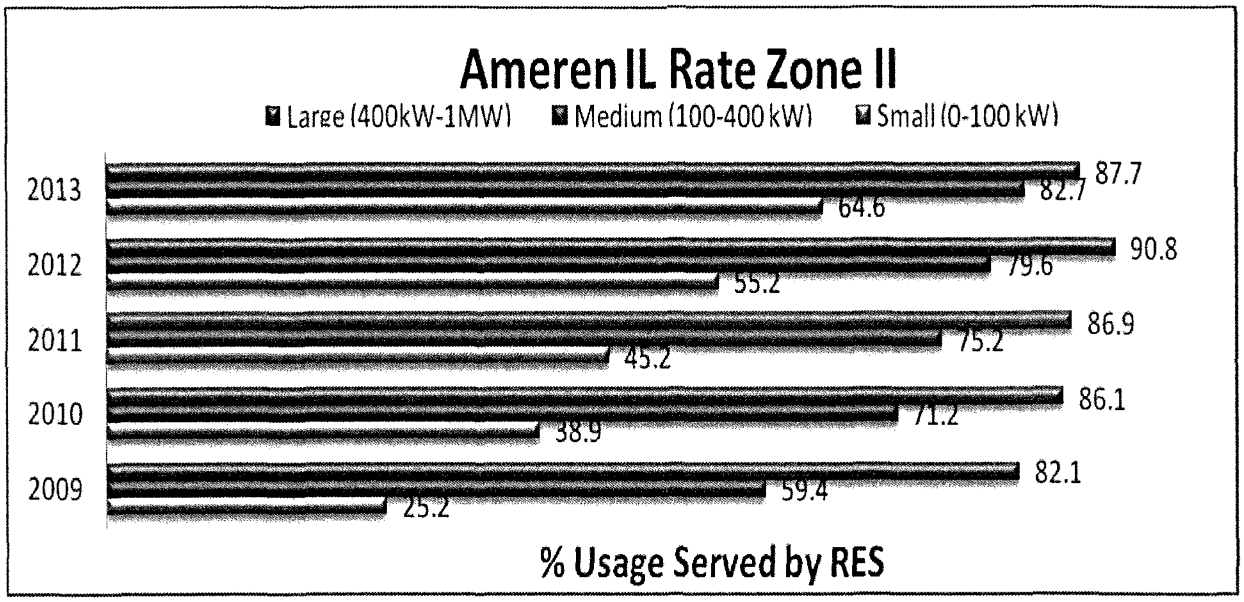
[7] Data as of May 31 of each year.



3. Ameren Illinois Rate Zone II (formerly AmerenCILCO)

As of May 31, 2013, 82% of the total electric usage of Rate Zone II customers was provided by alternative retail electric suppliers (up from 65% last year). About 65% of the electric usage of small commercial customers in Rate Zone II (up from 55%) and approximately 83% of electric usage for its medium commercial and industrial customers (up from 80%) was provided by ARES. For large customers it was 88% (down from 91%), and for customers with a demand of over 1MW, over 90% of the usage was served by alternative retail electric suppliers (down from 93% last year). Together, 85% of all non-residential load was provided by alternative retail electric suppliers as of May 31, 2013 (down slightly from 86% last year). The following shows the electric usage provided by ARES for the various commercial and industrial customer classes for the past four years[8].

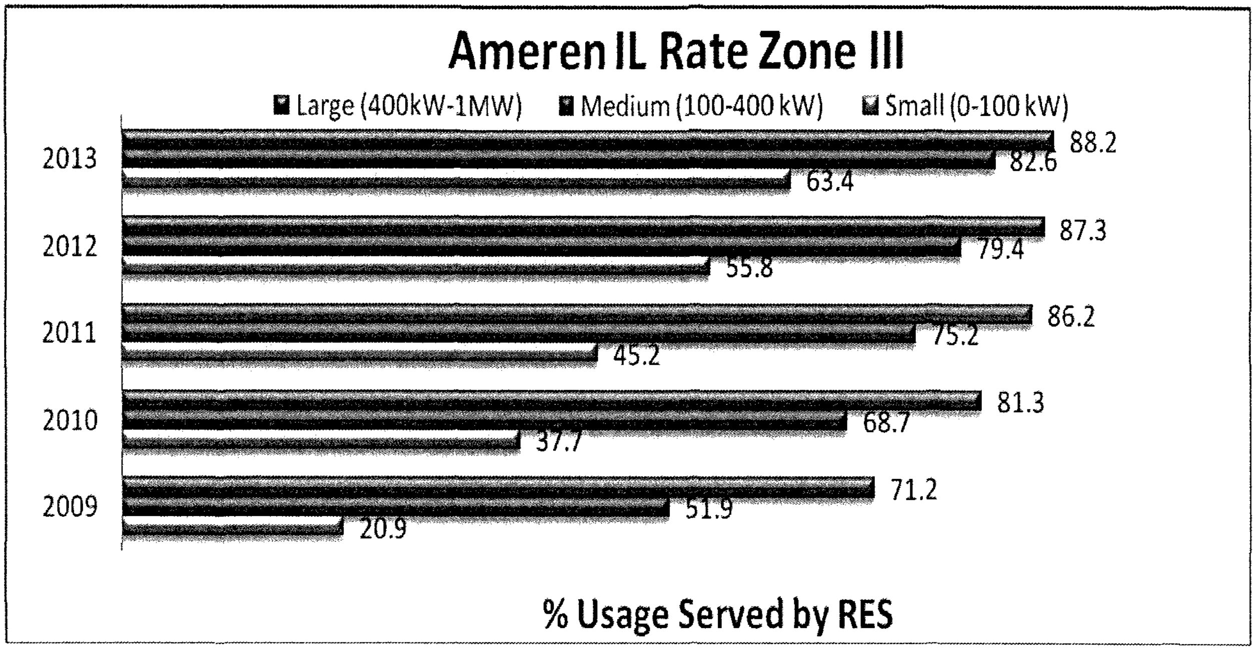
[8] Data as of May 31 of each year.



4. Ameren Illinois Rate Zone III (formerly AmerenIP)

As of May 31, 2013, almost 80% of the total electric usage of Rate Zone III customers was provided by alternative retail electric suppliers (up from 68% last year). About 63% of the electric usage of small commercial customers in Rate Zone III (up from 56%) and approximately 83% of electric usage for its medium commercial and industrial customers (up from 79%) was provided by ARES. For large customers it was 88% (up from 87%), and for customers with a demand of over 1MW, about 93% of the usage was served by alternative retail electric suppliers (down slightly from about 94% last year). Together, about 87% of all non-residential load was provided by alternative retail electric suppliers as of May 31, 2013 (which is the same as last year). The following shows the electric usage provided by ARES for the various commercial and industrial customer classes for the past four years[9].

[9] Data as of May 31 of each year.



5. Competitive Declarations

As of August 2007, Section 16-113(f) of the Act declared the provision of electric power and energy to retail customers of ComEd and Ameren Illinois with peak demands of at least 400 kilowatts to be a competitive service. The legislation resulted in ComEd's discontinuation of providing fixed-price bundled service to those customers after the end of the May 2008 billing period. The law similarly provided that Ameren Illinois does not need to provide fixed-price bundled service to that class of customers after the end of the May 2010 billing period.

In addition, Section 16-113(g) gives both ComEd and Ameren Illinois the ability to declare the provision of power and energy to customers with peak demands of at least 100 kilowatts but less than 400 kilowatts to be competitive if certain conditions are met. In 2007, ComEd filed a petition for competitive declaration and the Commission found that ComEd had satisfied the statutory requirements and therefore the provision of power and energy to those customers has been declared competitive as of November 2007[10]. As a result of the competitive declaration, after the end of the May 2010 billing period, all customers in the

10 ICC Docket No. 07-0478.

100-400kW class, with the exception of some statutorily exempted condominium associations, are taking supply service from the utility on an hourly-pricing basis or they are receiving service from an alternative retail electric supplier.

On March 1, 2011, Ameren Illinois filed a petition for competitive declaration of its customers with peak demands above 150 kilowatts but less than 400 kilowatts[11]. Ameren's petition stated that 67% of its customers with peak demands between 150 and 400 kilowatts were currently being served by an ARES. The Commission approved Ameren's petition on March 23, 2011 with the competitive declaration to be effective on May 1, 2011. Customers in this class will continue to receive fixed-price bundled utility service until May 2014 unless they elect to receive service from a retail electric supplier before that date. Going forward, the only non-residential customers still receiving a fixed-price supply service from the utility are ComEd customers with demand below 100kW and AIU customers with demand below 150kW. All other non-residential customers will receive their power from a competitive supplier or they will be on the utility's hourly-pricing option.

6. Market concentration

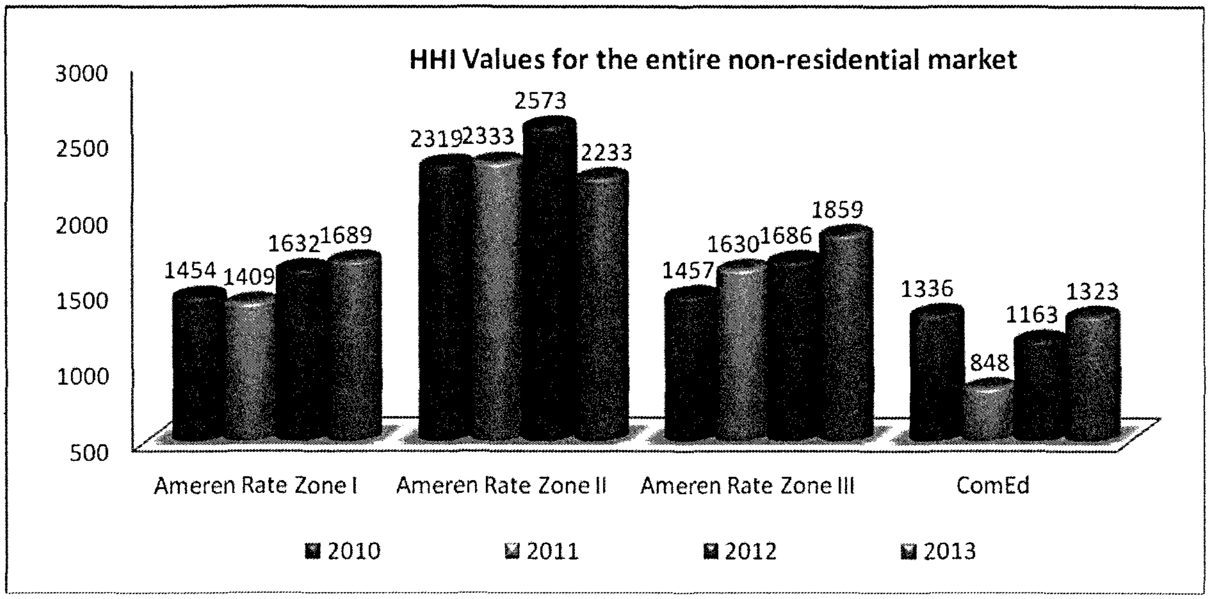
Similar to the last three annual reports, this year's report again analyzes the non-residential market shares of the individual ARES by looking at the share of electric usage provided by an ARES instead of the share of customers served by individual ARES. We believe either approach would be informative but we assume the amount of kWh served might be more closely related to an ARES' financial success than the number of customers it serves. In addition, when calculating market shares based on customer counts, we did not find significant differences from the values derived from using ARES-provided usage. We again used the Herfindahl-Hirschmann index, or HHI, which is a common indicator to measure competition among firms in a defined market. In order to put the resulting numbers into perspective, we looked at the revised 2010 Horizontal Merger Guidelines by the Department of Justice ("DOJ") and the Federal Trade Commission ("FTC"), which divide the spectrum of market concentration into three regions. Generally speaking, the revised guidelines state that the DOJ and the FTC view a market with an HHI below 1,500 as unconcentrated (meaning many similarly sized firms compete for the same customers), a

[11]ICC Docket No. 11-0192.

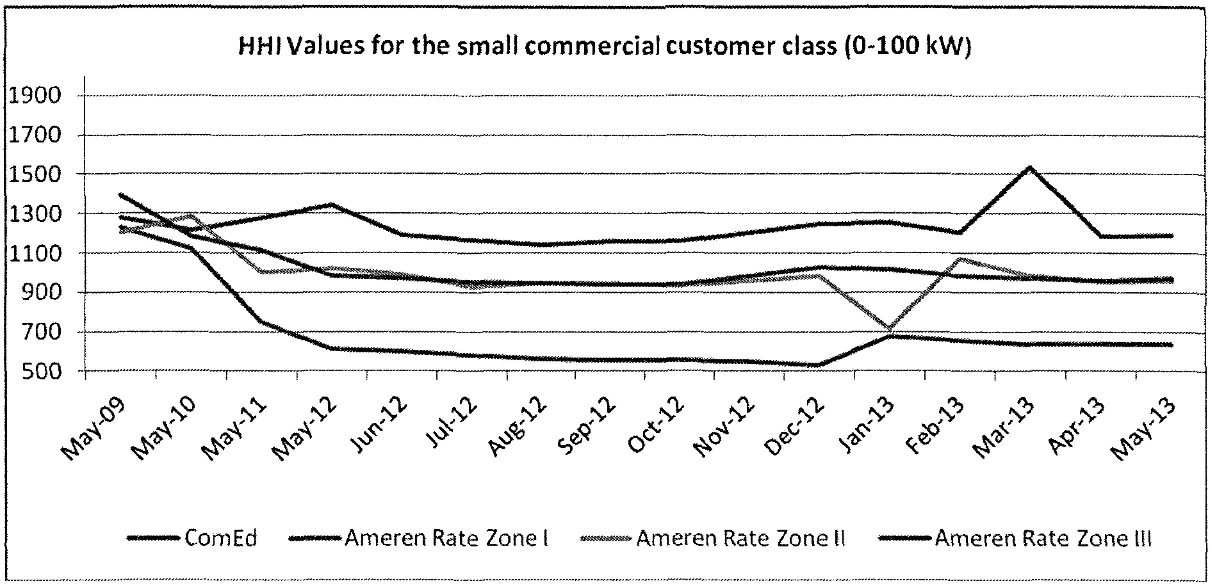
market with an HHI between 1,500 and 2,500 as moderately concentrated, and a market with an HHI above 2,500 as highly concentrated (very few firms dominating the market).

For this exercise, we again excluded retail electric suppliers that provide electric supply only to themselves or their subsidiaries or affiliates. We also need to emphasize that the numbers below reflect only the segment of the non-residential market that has already switched to a competitive supplier. In other words, the market concentration analysis shown here does not include the customers on utility fixed-price service (where available) or utility-provided hourly service.

The first graph shows the HHI values for the total non-residential market among the four utility service areas. While it is unreasonable to assume that all non-residential customer classes are considered to be part of the same market, the overall HHI values shown here display the trend in market concentration from May 2010 to May 2013. The values also allow a relative comparison among the utility service territories. As the graph shows, the ComEd non-residential market is generally less concentrated than the three Ameren Illinois markets. It also shows that ComEd's total non-residential market has been unconcentrated for all four years shown here. Ameren Illinois's Rate Zones are generally in the moderately concentrated range of 1,500 to 2,500, with the exception of the 2012 value for Rate Zone II. Three of the four utilities saw an increase in the 2013 values, while the most concentrated market, Ameren Illinois Rate Zone II, saw a decrease from last year, making it a moderately concentrated market, as defined by the DOJ and FTC guidelines.



Turning to the individual non-residential customer classes, our analysis shows that the small and medium non-residential customer segments continue to be the least concentrated. This is true for all four utility service areas. The following graph shows the HHI values for the small commercial class, with customers of demand up to 100kW. While the three Ameren Illinois areas show overall higher HHI values than the ComEd area, almost all of the HHI values are below 1,500, with most values well below that threshold. The graph shows the values for May 2009, May 2010, May 2011, May 2012, as well as the monthly HHI values for the past 12 months.



The next two larger customer segments (customers with demand between 100 and 400kW and customers with demand between 400kW and 1MW) showed somewhat higher market concentration but almost all HHI values were still below 1,500. Additionally, all HHI values, except for the 100-400 kW customer class in Ameren Rate Zone I, declined over the same period (May 2009 to May 2013) and the Ameren Illinois values were usually higher than the corresponding numbers for the ComEd area.

The situation changed more markedly, however, in the market for the largest commercial and industrial customers. While the HHI values for ComEd's 1-10MW demand class have been generally in the 1,400 to 1,800 range, ComEd's over 10MW demand class has seen a recent increase in market concentration with an HHI value of about 2,100 for the month of May 2013. Some customer segments in the Ameren territory, however, showed significantly higher HHI values. Most HHI values for the over 1MW demand classes in Ameren Illinois's territory have been in the 2,000 to 2,800 range, with the 3-6MW demand class and the over 6MW demand class in Ameren Rate Zone II showing HHI values above 4,000 over the past year.

In sum, according to the revised guidelines by the DOJ and FTC, most non-residential customer segments exhibit HHI values that would classify them as unconcentrated or moderately concentrated markets. The data also reveals that market concentration increases with the size of the non-residential customer and that the Ameren Illinois markets are generally more concentrated than the ComEd market. With the exception of the largest non-residential customer classes in Ameren Illinois' Rate Zone II, there appears to be effective competition among the active retail electric suppliers in all non-residential customer segments at this time.

7. Residential activity

In last year's report, we stated that, compared to 2011, the residential landscape in Illinois looked quite different in 2012. It is fair to say that the residential market looks quite different yet again a year later. As the next pages will show, due mostly to government aggregation, residential switching numbers, and market concentration levels, have markedly changed from last year.

As we did in last year's report, we will attempt to capture the residential activity by looking at four different indicators. We start by looking at the number of residential customers switching away from the utility supply service in each of the previous twelve months and for each of the four utility areas. We will then look at the increase in the number of certified and active suppliers and the number and types of residential offers that those suppliers have posted on our website, PlugInIllinois.org. Third, we will provide a market-share analysis of the residential ComEd market over the last twelve months. Lastly, we provide an estimate of savings (in dollars) realized by the residential customers that have switched from ComEd to an ARES over the last year.

a) Customer switching

As of the end of May 2013, nearly 3 million residential customers had switched away from the utility. The following table shows the substantial increase in residential ARES customers over the last twelve months. It shows the number, as well as the percentage, of residential customers who are receiving supply from a competitive supplier.

Residential Customers on Competitive Supply

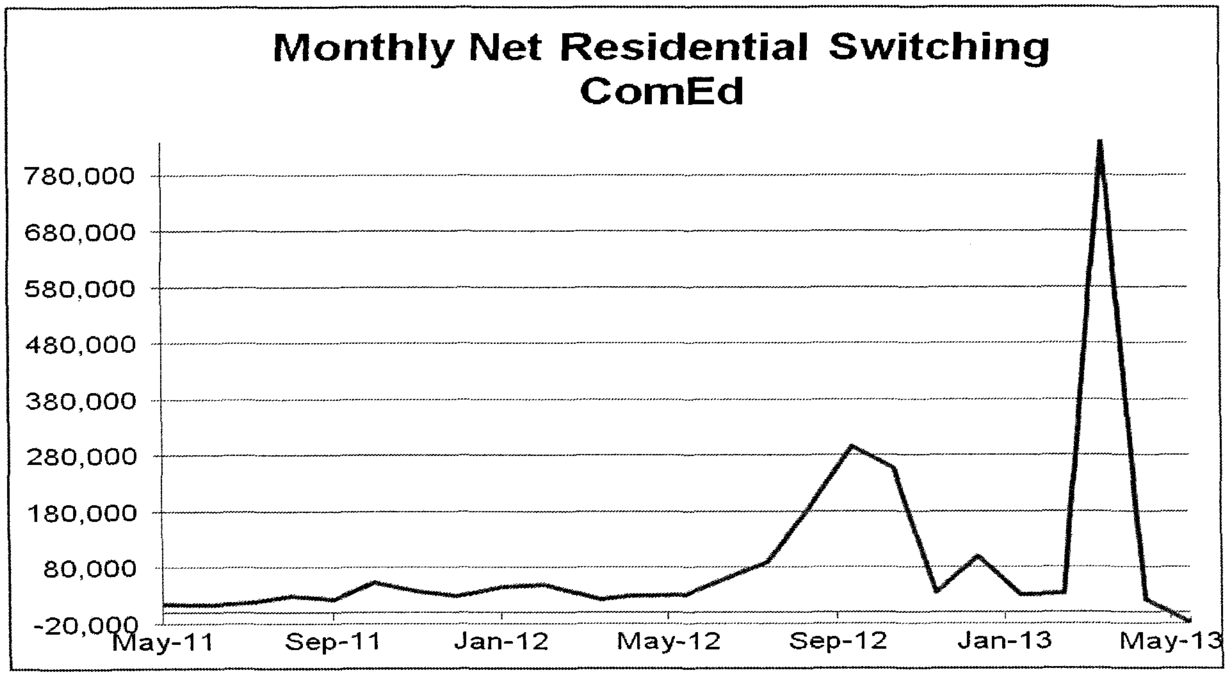
	May 2011	May 2012	May 2013
Ameren Illinois Rate Zone I:	78	28,459	147,513
Ameren Illinois Rate Zone II:	23	12,752	138,163
Ameren Illinois Rate Zone III:	72	47,124	277,229
ComEd:	21,276	406,144	2,312,654
Total:	21,449	494,479	2,875,559
Ameren Illinois Rate Zone I:	0.02%	8.7%	45.2%
Ameren Illinois Rate Zone II:	0.01%	6.8%	73.2%
Ameren Illinois Rate Zone III:	0.01%	8.7%	51.2%
ComEd:	0.63%	11.9%	67.7%

Whereas just under twelve percent of ComEd's residential customers had been with a supplier as of May 2012, almost 68% are receiving service from a supplier one year later. The number of Ameren Illinois's residential customers on competitive supply increased from around 90,000 in May 2012 to over half a million as of May 2013. To look at these numbers in a different way, the switching pace increased from about 1,300 residential customers per day between May 2011 and May 2012 to about 6,500 residential customers per day between May 2012 and May 2013.

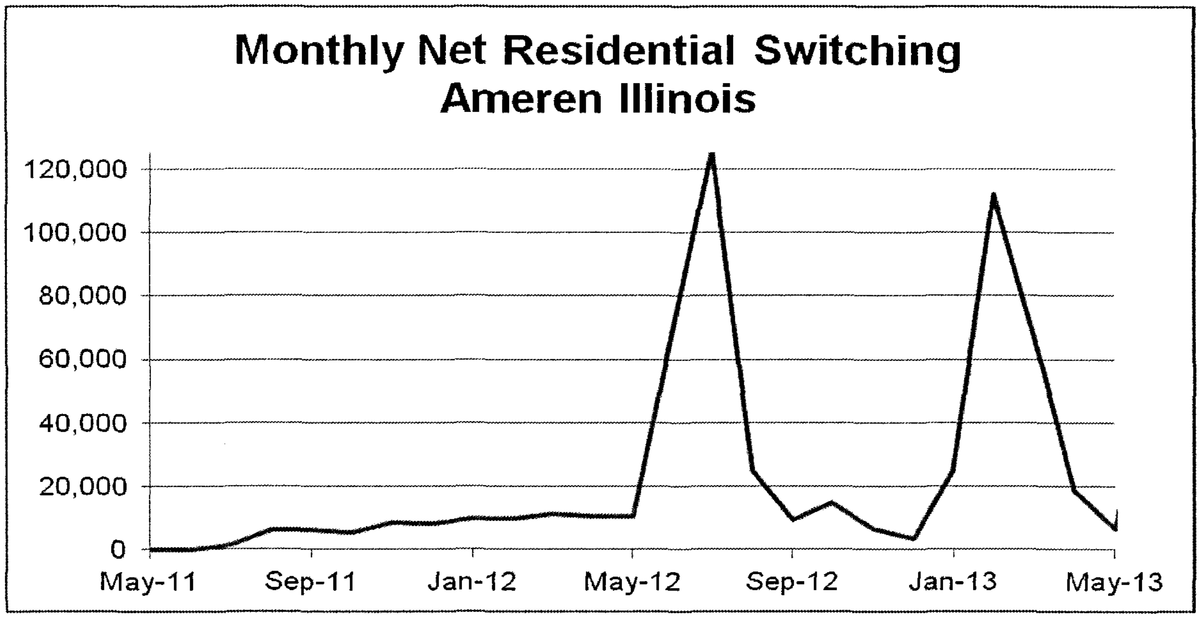
Whereas last year only 17% of residential RES customers were part of a government aggregation program, more than 2.2 million, or almost 78% of the approximately 2.9 million residential RES customers, are part of a government aggregation program a year later. Broken down by utility area, 430,298 of the 562,905 residential RES customers in Ameren

Illinois' areas are government aggregation customers and 1,803,919 of the 2,312,654 residential RES customers in ComEd's area are government aggregation customers.

The following two graphs show the monthly residential switching numbers for ComEd and the combined Ameren Illinois service areas.

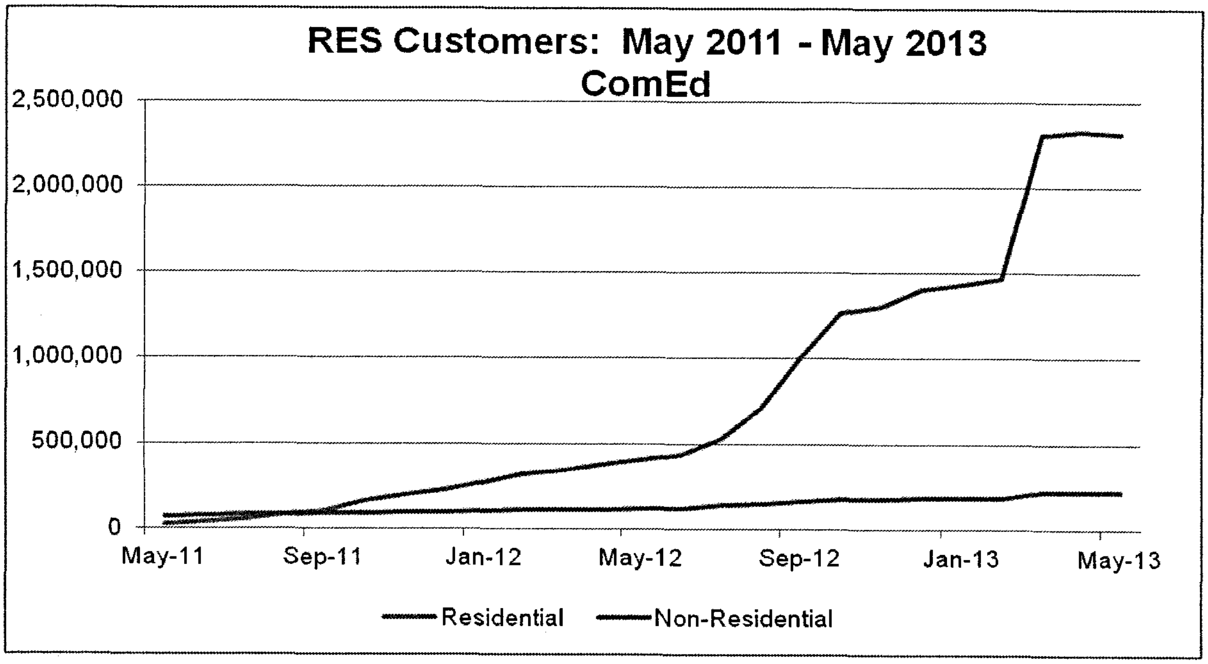


ComEd's numbers show the spikes in switching following municipal aggregation initiatives. Besides the mass switching of the City of Chicago aggregation customers earlier this year, the graph shows the impact of the March 2012 aggregation referendums on the August-October 2012 switching statistics. It also shows negative net switching from April to May 2013 for the first time in ComEd's service area.

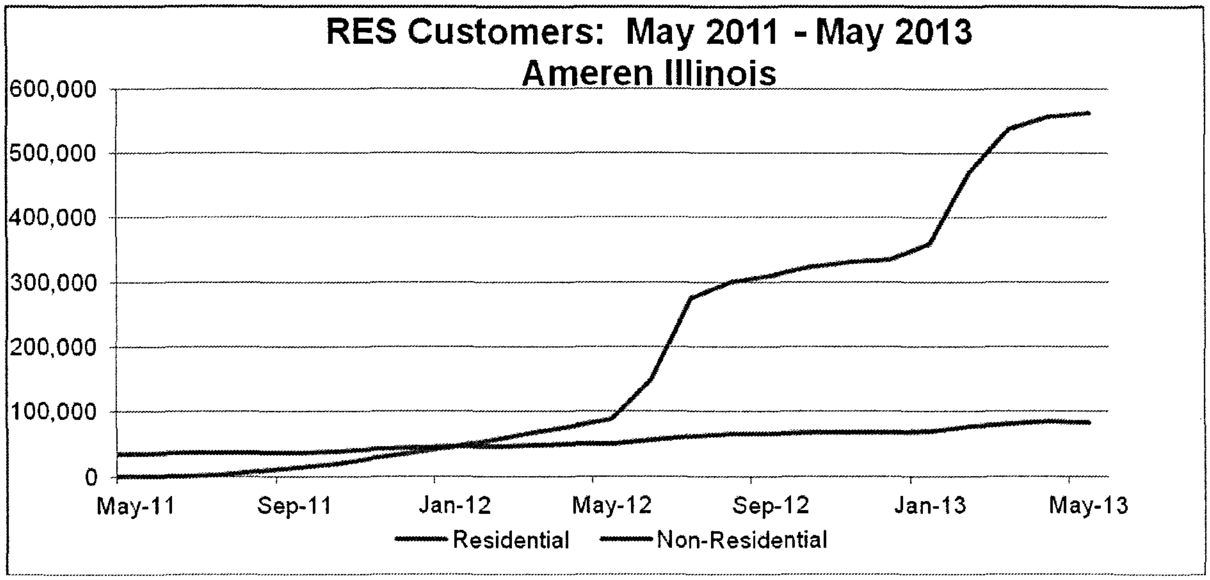


Similar to ComEd, the two major spikes in switching activity followed the March 2012 and November 2012 municipal aggregation referendums. As of May 2013, about 45% of residential customers in Rate Zone I, about 51% in Rate Zone III, and more than 73% in Rate Zone II have switched to a competitive supplier.

To demonstrate the substantial increase in residential activity from a different angle, the following graphs show the suppliers' total non-residential customers in relation to the suppliers' total residential customers. Depicting the customer levels for the past 24 months, the graphs show that suppliers, in the aggregate, now have more residential than non-residential customers.

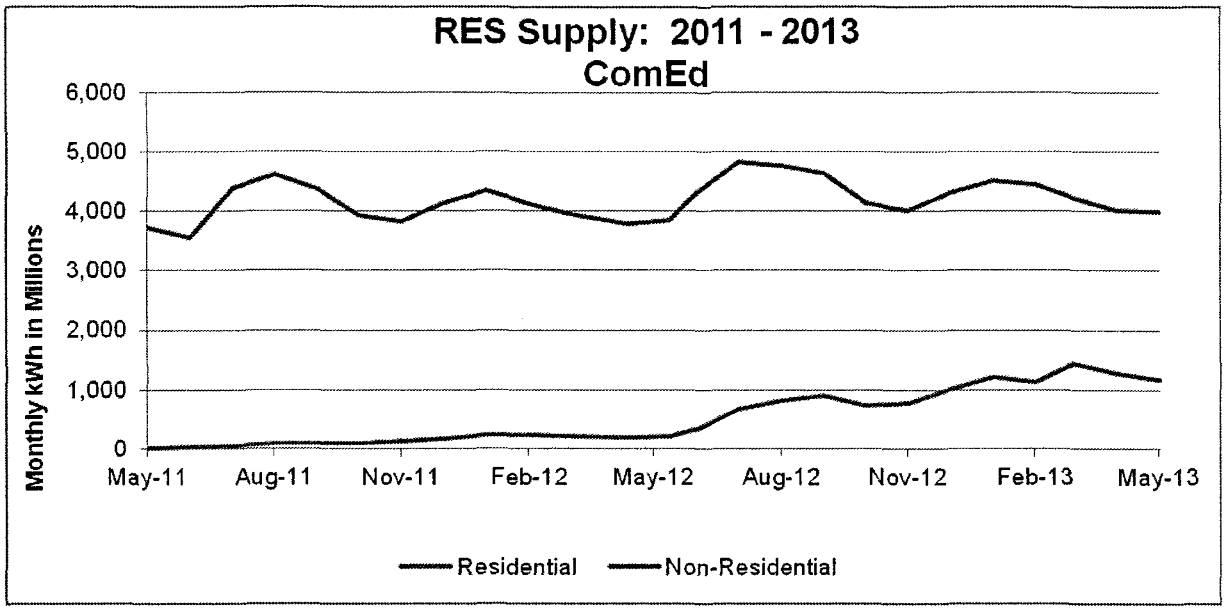


While the number of non-residential customers on competitive supply has been steadily, but slowly, increasing over the depicted two-year period, the number of residential ARES customers has gone from just over 20,000 in May 2011 to more than 2.3 million in May 2013. As a whole, competitive suppliers now have more than ten times as many residential customers as they have non-residential ARES customers.



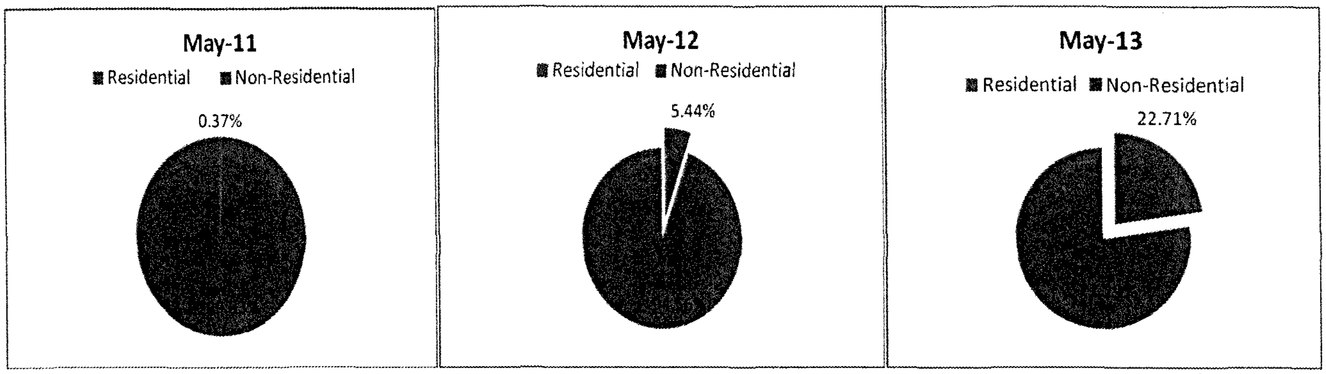
Looking at the same data for the three Ameren Illinois Rate Zones combined reveals the gradual increase in non-residential ARES customers over the last two years in Ameren Illinois's service territory as well. As a whole, competitive suppliers now have about seven residential customers for every non-residential RES customer.

Of course, looking at the number of customers gives us only a portion of the overall picture. The following charts show that even the recent substantial increase in residential customers has not changed the fact that, as a whole, suppliers provide substantially more electricity to non-residential than to residential customers.



The first graph shows the seasonal variation in the RES-provided non-residential supply over the last two years. Any seasonal variation in the RES-provided residential supply is overshadowed by the constant increase in RES-provided supply as a result of additional switching.

Residential and Non-Residential Share of RES Supply



In terms of monthly kilowatt hours, the active suppliers in ComEd's service territory have been providing upwards of 3.5 billion kWh per month to their non-residential customers for several years. While the non-residential usage provided by the suppliers continues to be lion share of RES-provided usage, the electricity provided to residential customers has grown from less than one-half of a percent two years ago to almost a quarter of the entire usage provided by the competitive suppliers today.

C. Municipal/Government Aggregation

Effective January 1, 2010, Public Act 96-0176 amended the Illinois Power Agency Act ("IPA Act") by allowing municipalities and counties to adopt an ordinance under which it may aggregate electrical load. Specifically, it allows municipal corporate authorities or county boards to adopt an ordinance under which it may aggregate residential and small commercial retail electrical loads located within their jurisdiction and solicit bids to enter service agreements for the sale and purchase of electricity and related services and equipment.

The law requires the corporate authorities of a municipality, township, or county board to submit a referendum to its residents to determine whether or not the aggregation program shall operate as an opt-out program for residential and small commercial customers prior to the adoption of an ordinance for the aggregation of these loads.

Municipal aggregation activity remained very high this past year, with 207 communities passing opt-out aggregation referendums on the November 2012 election ballot and another 204 opt-out referendums passing in the April 2013 election. The following table compares the municipal aggregation activity over the last four elections:

Municipal Aggregation Statistics

	April 2011	March 2012	November 2012	April 2013
Referendums Passed	20	246	207*	204*
Aggregation Programs Announced or Implemented	19	244	192*	99*
# of "winning" suppliers – ComEd	4	8	8*	3*
# of "winning" suppliers – Ameren Illinois	N/A	3	5*	1*
Average Rate – ComEd	5.75*	4.85	5.107	5.40*
Average Rate - Ameren Illinois	N/A	4.12	4.11*	4.30*

* As of June 28, 2013

Combining the number of aggregation communities from the four referendum dates, 677 communities have passed an opt-out referendum to date. The number of different "winning" suppliers, meaning the aggregation suppliers being selected by the community leaders, has increased to a total of twelve. Breaking it down further, eleven different suppliers have been awarded contracts in ComEd's area and five different suppliers have been awarded contracts in Ameren Illinois' areas. Four of the five aggregation suppliers in Ameren Illinois' area are also aggregation suppliers in the ComEd service area. Given the latest election occurred just over two months before the preparation of this report, less than half of the aggregation communities have announced the terms of their aggregation programs as of the date of this report. This may explain why the number of winning suppliers following the latest referendums is very small for both the ComEd and the Ameren Illinois areas.

The data gathered from publicly available information shows that the simple average electric supply rate of the communities with announced or implemented aggregation programs shows some variation depending on the date of the referendum[12]. While the data for the communities with an April 2013 referendum date continues to trickle in, the table shows that the lowest prices have generally been achieved by the communities with a referendum date of March 2012. Based on the limited information following the April 2013 election, there is a notable increase in the average supply rate compared to the average rate of the previous aggregation referendum dates.

a) Residential Savings Estimate

In last year's report we included an estimate of the total annual savings realized by residential RES customers in ComEd's service area. We looked at the 12-month period from June 2011 to May 2012 and we compared the amount residential customers as a whole spent on RES service to the amount those customers would have spent had they stayed on ComEd's fixed-price bundled service. We took into account the fact that some customers switched away from the discounted utility space-heat rate and we calculated the savings with and without the effects of the Purchased Electricity Adjustment ("PEA")[13].

The following table is the one that appeared in last year's report. It shows aggregate residential savings of around $24 million, with about $17 million resulting from comparing the suppliers' average rate to ComEd's Price-to-Compare ("PTC"). The ComEd PTC is comprised of the Electric Supply Charge and the PJM Transmission Services Charge. The remaining $7 million in savings result from the application of the PEA for ComEd supply customers.

[12] The information for the 2013 aggregation programs is reflective of data that was available as of June 28, 2013. Updated information can be found at http://www.icc.illinois.gov/ORMD/MunicipalAggregation.aspx.

[13] The PEA is a monthly fluctuating true-up mechanism for the utility, matching incurred supply costs to actual received supply revenues. The PEA is therefore a credit in some months and a charge in others.

	Monthly Savings compared to ComEd's PTC	Monthly Savings inclusive of the PEA Impact	Monthly PEA Impact	Monthly Average Savings compared to ComEd's PTC (in cents per kWh)	Monthly Average Savings inclusive of the PEA (in cents per kWh)
June 2011	$255,293	$349,039	$93,746	0.882	1.206
July 2011	$502,260	$778,145	$275,885	0.910	1.410
August 2011	$956,507	$1,429,718	$473,211	1.011	1.511
September 2011	$884,986	$1,331,358	$446,371	0.991	1.491
October 2011	$844,688	$1,309,784	$465,096	0.908	1.408
November 2011	$1,048,318	$1,293,767	$245,449	0.769	0.949
December 2011	$1,502,112	$1,285,104	-$217,008	1.045	0.894
January 2012	$2,247,509	$3,226,106	$978,597	1.079	1.549
February 2012	$2,240,491	$3,360,753	$1,120,261	1.000	1.500
March 2012	$2,193,423	$3,249,138	$1,055,715	1.039	1.539
April 2012	$2,178,678	$3,176,113	$997,435	1.092	1.592
May 2012	$2,365,072	$3,453,785	$1,088,713	1.086	1.586
Totals	**$17,219,337**	**$24,242,809**	**$7,023,472**		
Average	**$1,434,945**	**$2,020,234**	**$585,289**	**0.984**	**1.386**

For the June 2011 through May 2012 period, the average savings per kWh was close to 1 cent when compared to ComEd's Price-to-Compare and close to 1.4 cent when taking into account the Purchased Electricity Adjustment.

We stated in last year's report that "given the recent substantial municipal aggregation activity and some announced residential rates of well-below 5 cents per kWh, it is likely that the total residential savings for the June 2012 to May 2013 period will dwarf the savings estimate shown here." After performing the calculations for the past twelve months, this prediction did indeed prove correct, as the following table shows:

	Monthly Savings compared to ComEd's PTC	Monthly Savings inclusive of the PEA Impact	Monthly PEA Impact	Monthly Average Savings compared to ComEd's PTC (in cents per kWh)	Monthly Average Savings inclusive of the PEA (in cents per kWh)
June 2012	$1,707,557	$3,261,660	$1,554,104	0.549	1.049
July 2012	$4,718,151	$7,715,204	$2,997,053	0.787	1.287
August 2012	$8,978,217	$12,743,479	$3,765,262	1.192	1.692
September 2012	$12,197,497	$16,453,594	$4,256,097	1.433	1.933
October 2012	$19,539,873	$22,973,699	$3,433,826	2.845	3.345
November 2012	$19,585,006	$23,157,442	$3,572,436	2.741	3.241
December 2012	$25,059,221	$26,152,327	$1,093,106	2.292	2.392
January 2013	$30,137,351	$29,003,509	-$1,133,842	2.658	2.558
February 2013	$28,478,230	$33,492,012	$5,013,782	2.840	3.340
March 2013	$36,485,104	$29,889,800	-$6,595,303	2.766	2.266
April 2013	$32,932,278	$27,059,548	-$5,872,730	2.804	2.304
May 2013	$31,009,412	$36,411,291	$5,401,879	2.870	3.370
Totals	$250,827,896	$268,313,565	$17,485,670		
Average	$20,902,325	$22,359,464	$1,457,139	2.148	2.398

In order to calculate how much residential customers have saved by switching away from the utility, one needs at least three different sets of data: 1) the rate the customers would have paid under the utility's default rate, 2) the rate the customers actually paid under the supplier's rate, and 3) the amount of electrical usage each supplier provided to their customers. Monthly reports from ComEd and Ameren Illinois provide us with the necessary usage information, and the utilities' default rates are tariffed rates. As for the suppliers' prices, similar to last year, almost all suppliers provided us with monthly average residential rates for the past twelve months in response to a Staff Data Request. Also the same as last year, we decided to limit this savings estimate to residential customers in the ComEd area. Ameren Illinois's rate structure, while more streamlined as a result of recent tariff changes, contains non-summer rates that vary with a customer's usage, and as such would have necessitated further average usage assumptions.

It is important to keep in mind that these are total, or aggregate, savings and that the savings for individual customers differ from these averages. For example, many government aggregation programs have rates of three or four cents per kWh below ComEd's PTC during the depicted twelve-month period, yet the estimated average savings per kWh are mostly in the two to three cent range. Also, not captured in these numbers are rewards and incentives that are not part of the suppliers' electric supply rates. For example, several suppliers offer one-time gift cards as an incentive to sign up for a particular offer and other offers contain rewards such as airline miles and other non-rate benefits. In addition, not every customer saved money in every month during the one-year period. However, as there are probably a variety of reasons residential customers switch from a utility's default supply service to a supplier's offering, it is likely that the opportunity to save money is a primary reason for many residential customers.

For the twelve-month period from June 2012 to May 2013, it is estimated that the total savings amount to approximately $268 million. The monthly average savings of about $22 million is close to the entire estimated savings of approximately $24 million for the previous year.

To break down the total savings estimate further, the data shows that about $251 million of the $268 million in savings result from comparing the suppliers' average rate to ComEd's Price-to-Compare. The remaining $17 million in savings result from the application of the PEA for ComEd supply customers. During the twelve months from June 2012 to May 2013, the PEA was a credit for three months and a charge for nine months. In eight of those nine months, the Purchased Electricity Adjustment was a charge of 0.5 cents per kWh. The data shows that the average savings per kWh during the June 2012 through May 2013 period was about 2.6 cents when compared to ComEd's Price-to-Compare (up from around 1 cent during the previous year) and close to 3 cents when taking into account the Purchased Electricity Adjustment (up from around 1.4 cent during the previous year).

Lastly, it seems fair to say that given the recent substantial drop in both ComEd and Ameren Illinois' PTC, it is likely that the savings estimate for the past twelve months will not be repeated anytime soon.

b) Active suppliers

Having looked at the customer switching numbers, the following table shows the increase in residential supplier activity over the last two years.

Residential Suppliers

	May 2011	May 2012	May 2013
ComEd - ICC certified	22	40	57
ComEd -- active	8	27	42
Ameren IL - ICC certified	16	26	33
Ameren IL -- active	3	10	17

The table above shows that a large number of suppliers that had already received residential ICC certification by May of 2011 did not actively seek residential customers until 2012. Also, 35 additional suppliers applied for and received a residential certification in the past 24 months. While the gap between the ComEd and Ameren Illinois markets remains, it is encouraging to report 17 suppliers with residential customers in the Ameren Illinois areas. Of note, all suppliers that have residential customers in the Ameren Illinois areas also have residential customers in the ComEd area.

An additional indicator of supplier activity is the number of residential offers posted on PlugInIllinois.org. The "Compare Offers Now" portion of the website went live in July 2011 and has seen a steady stream of additional suppliers and residential offers since that date. The tables below show that the number of suppliers as well as the number of offers by these suppliers continues to increase. Most of the activity has been in the ComEd area but customers of Ameren Illinois are able to choose from a host of residential offers as well.

Residential Suppliers Posting on PlugInIllinois.org

Utility Area	# of Suppliers posting in July 2011	# of Suppliers posting in May 2012	# of Suppliers posting in April 2013
ComEd -- Total	9	20	28
Ameren IL - Total	3	6	10

Residential Offers Posted on PlugInIllinois.org

Utility Area	# Offers in July 2011	# Offers in May 2012	# Offers April 2013
ComEd - Total	31	61	63
Ameren IL - Total	3	11	20

Given the large number of residential offers for ComEd customers, we decided to take a closer look at the type of offers posted so far. The following table compares the type of offers posted in July 2011 and May 2012 to the type of offers posted in April 2013.

[illegible]	[illegible]	[illegible]	[illegible]
Total	31	61	63
Fixed	28 (90%)	51 (84%)	46 (73%)
Variable	3 (10%)	10 (16%)	17 (27%)
Fixed with Early Termination Fee	20 (71%)	34 (67%)	29 (63%)
Fixed without Early Termination Fee	8 (29%)	17 (33%)	17 (37%)
< than 12-month Term	1 (4%)	6 (12%)	23 (37%)
12-month Term	16 (57%)	26 (51%)	28 (44%)
13-23 month Term	2 (7%)	3 (6%)	2 (3%)
24-month Term	8 (29%)	16 (31%)	10 (16%)
> than 24-month Term	1 (4%)	1 (2%)	0 (0%)
Green/Renewable	9 (29%)	21 (34%)	18 (29%)

The table allows us to make several observations. First, while their share has declined over the last two years, fixed price offers still represent a substantial majority of the offers. Second, while six out of ten fixed offers have either a one-year or two-year term, the number of two-year offers has seen a significant drop from May 2012 to April 2013. Furthermore, none of the 63 offers posted in April 2013 has a term longer than two years. On the other hand, more than a third of the offers had a term of less than one year in April 2013, a marked change form the previous two years. Third, slightly less than two thirds of the fixed offers have an early termination fee. And finally, about a third of all offers have a "green"/renewable content higher than what is required by the state's renewable portfolio standard.

Besides analyzing the *type* of offers, we thought it would be informative to take a look at the prices for the various posted offers and how those prices might have changed during that same time period. The following table shows the average prices for the different types of offers posted on PlugInIllinois.org. The bottom of the table shows ComEd's fixed-price supply service rate for the three months in question. The ComEd rates shown include the Purchased Electricity Adjustment ("PEA").

Type of Residential Offer	July 2011 Average Price (in cents/kWh)	May 2012 Average Price (in cents/kWh)	April 2013 Average Price (in cents/kWh)
Fixed	6.81	6.37 (-6%)	6.21 (-3%)
Variable	7.67	7.00 (-9%)	7.07 (+1%)
Fixed with Early Termination Fee	6.64	6.35 (-4%)	6.00 (-6%)
Fixed without Early Termination Fee	6.64	6.32 (-5%)	5.64 (-12%)

< than 12-month Term	6.98	6.14 (-12%)	6.78 (+9%)
12-month Term	6.65	6.52 (-2%)	5.92 (-10%)
13-23 month Term	6.80	6.33 (-7%)	6.22 (-2%)
24-month Term	6.57	6.15 (-6%)	5.60 (-10%)
> than 24-month Term	6.30	6.30 (no change)	N/A
Green/Renewable	7.47	6.98 (-7%)	6.83 (-2%)
ComEd Price-to-Compare, incl. PEA	8.42	8.23	8.802

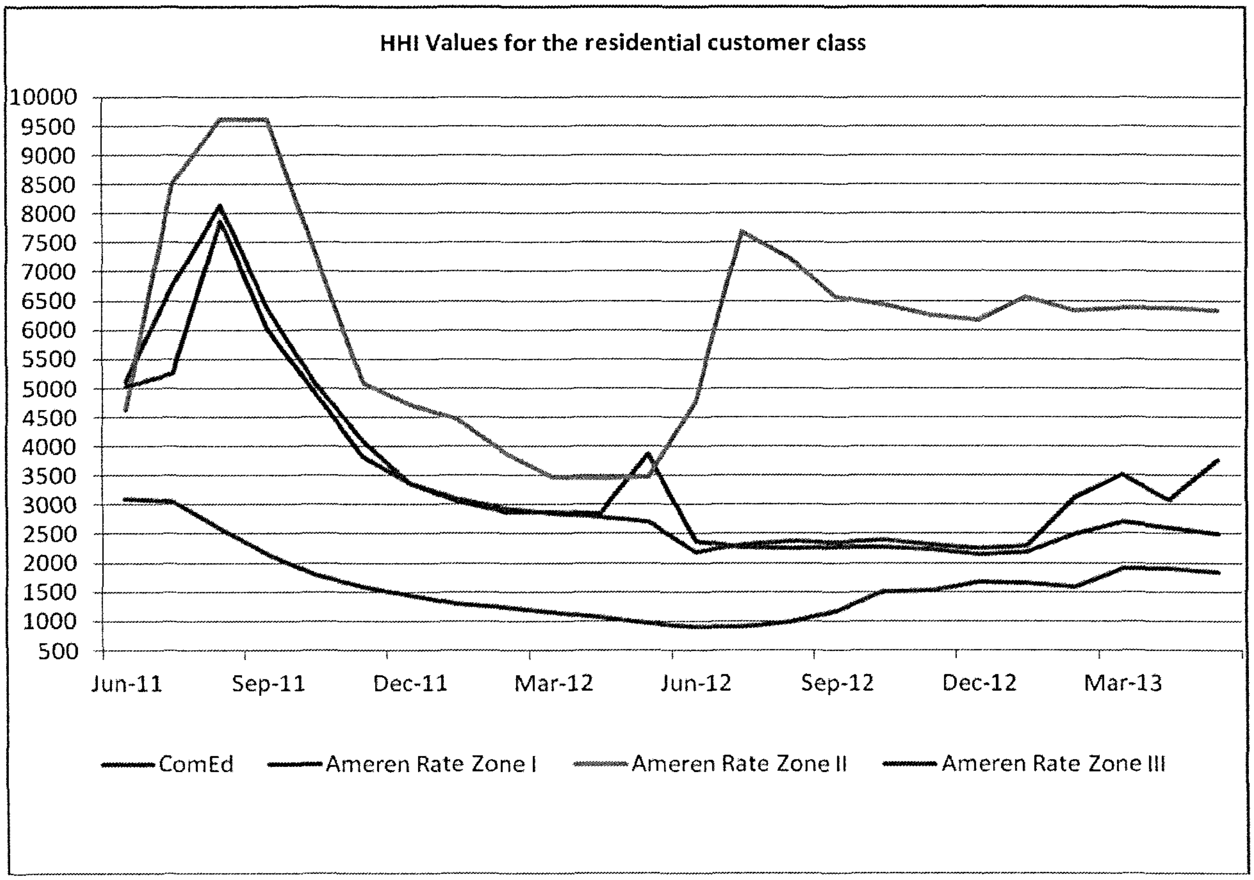
The comparison shows that the average price of the various types of offers was well below ComEd's then-effective fixed price bundled service rates for all of the three selected months. Moreover, the average prices of the posted ARES offers generally decreased between May 2012 and April 2013. The exceptions are variable offers and fixed offers with less than a 12-month term. The biggest drop in average prices occurred for offers with one- and two-year terms. In addition, the table shows that the average posted price for an offer *without* an early termination fee was actually lower than the average posted price for an offer *with* an early termination fee. Finally, looking at the average prices for the different term lengths, it shows that the average price for a twelve-month fixed offer was higher than the average price for a 24-month fixed offer. This was the case in July 2011, May 2012, and April 2013.

c) Residential market concentration

As the previous section on supplier activity suggests, currently there is significantly less market concentration in the ComEd residential market than in the Ameren Illinois residential market. However, compared to a year ago, there is more concentration in the ComEd residential market, which is primarily due to government aggregation. The following graph shows the monthly HHI values for the residential class in both ComEd and Ameren Illinois' areas from June 2011 to May 2013.[14]

The graph illustrates several trends. First, ComEd's residential market continues to be less concentrated compared to the three Ameren Illinois Rate Zones. Second, the market concentration in ComEd's market decreased steadily between the summer of 2011 and the summer of 2012. In the late summer/early fall of 2012, the impact of the aggregation programs from the March 2012 referendums can be seen in the graph. Whereas the ComEd residential market had HHI values of just over 900 a year ago, recent numbers show a doubling of those values. Third, although it exhibited large fluctuations over the last two years, Ameren's Rate Zone II continues to be the most concentrated residential market. Fourth, Ameren's Rate Zone I has been moving into the "moderately concentrated" area very recently, albeit barely.

[14] The HHI values are based on residential usage, rather than number of customers. However, there is not a substantial difference between using number of customers and amount of usage for the market share calculation.



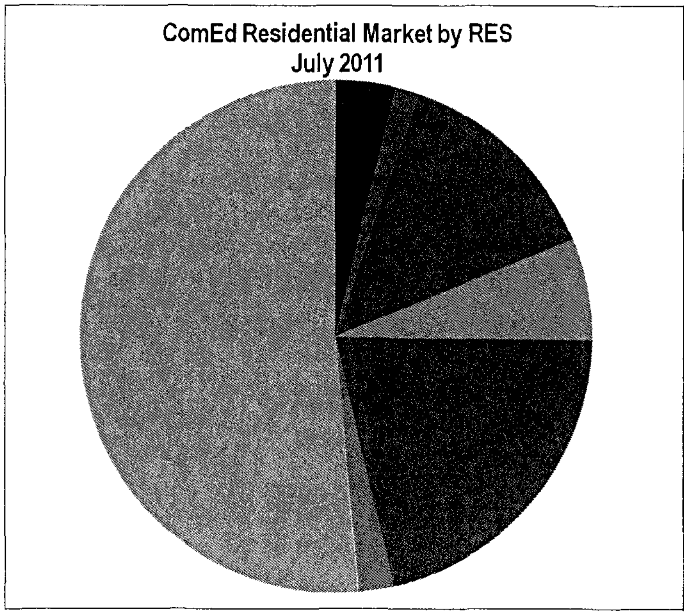
Having looked at the HHI values for the different utility service areas, we decided to take a closer look at the ComEd residential market. The HHI values shown above already tell us that the current market would be considered "moderately concentrated" per the DOJ and FTC's Merger guidelines. The next table highlights the changing market dynamics over the last two years:

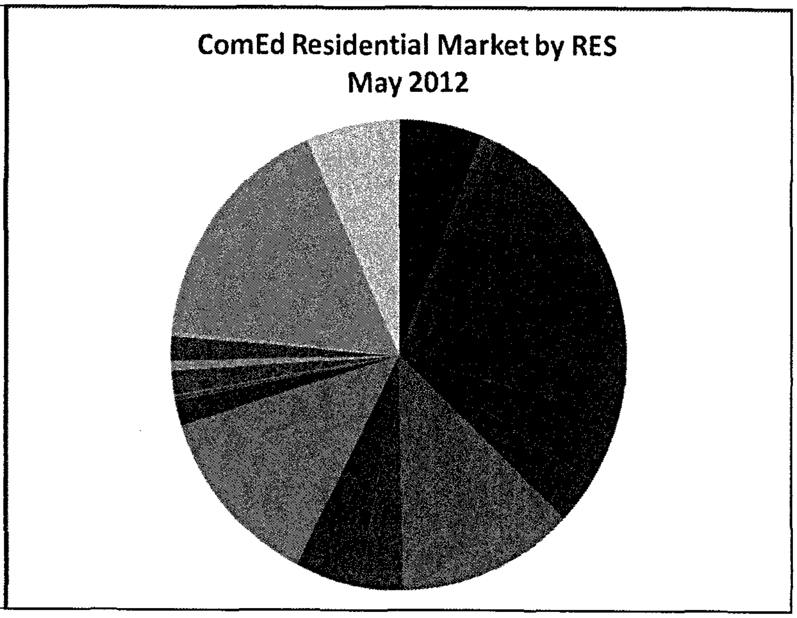
ComEd Residential Market Shares by Customers

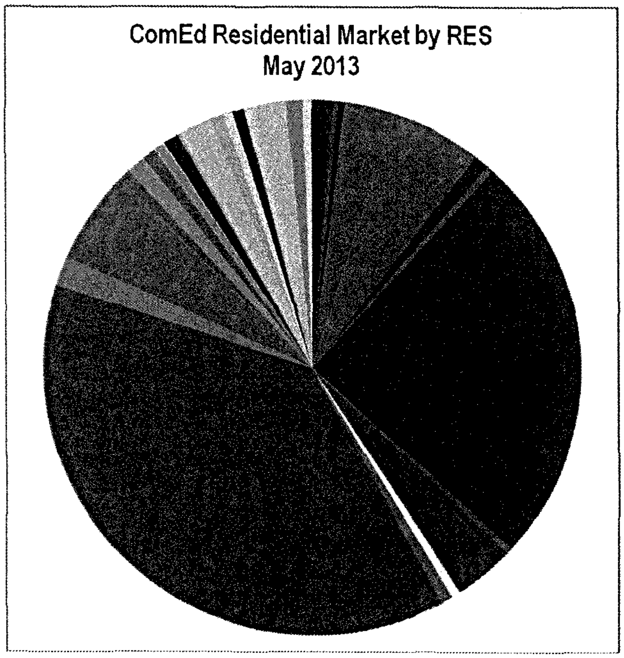
	June 2011	October 2011	February 2012	May 2012	October 2012	May 2013
Share of largest 3 suppliers	86%	66%	53%	44%	57%	69%
# of suppliers with customers	8	16	20	27	32	41
# of suppliers with >15% share	2	2	3	1	1	2
# of suppliers with >5% share	2	3	4	5	4	2
# of suppliers with <5% share	4	11	13	21	27	37

It shows that the market share of the three suppliers with the highest market share (in terms of residential customers) basically halved between June 2011 and May 2012 (decreasing from 86% to 44%) and then increased to more than two-thirds of the market one year later. What the table does not show, however, is that the three "largest" suppliers in a particular month were not always the same suppliers during this time period. Worth noting is that 37 of the 41 suppliers with residential customers had a market share of less than 5%. Not shown here is the fact that 29 of those 37 suppliers had a market share of less than one percent in May 2013. Only two suppliers had a market share above 15% and two suppliers had a market share between 5% and 15%. Finally, the table reveals how the market saw the entry of an additional 14 suppliers with residential customers over the course of the last twelve months.

The following three pie charts are the most striking visual representation of the changes in supplier diversity. The first chart shows the make-up of ComEd's residential market in July 2011, the second chart shows the composition as of May 2012, and the third chart represents the most recent data.


ComEd Residential Market by RES
July 2011


ComEd Residential Market by RES
May 2012


ComEd Residential Market by RES
May 2013

III. Public Act 95-0700

In 2007, the Illinois General Assembly passed a law designed to remove certain barriers to competition for residential and small commercial electric customers in Illinois. The provisions of this law, Public Act 95-0700, require ComEd and Ameren Illinois to offer utility consolidated billing ("UCB") and the purchase of receivables ("POR"). Under UCB, an ARES electronically submits its monthly customer charges for power and energy to the utility which then places those charges, along with its delivery charges, on one single bill to the customer. Under POR, an ARES is able to sell its receivables (the amount that customers owe to that ARES) to the utility at a discount. The POR requirement encourages alternative suppliers to offer their services to every utility customer rather than serve only those above certain credit thresholds, thereby furthering the statutory goal of an "effectively competitive retail electricity market that operates efficiently and benefits *all* Illinois consumers."

While Sections 16-118(c) (POR) and 16-118(d) (UCB) appear to be separate and distinct requirements, the utilities have so far focused on an offering that would combine the purchase of receivables with the provision of utility consolidated billing. That is, if a supplier enrolls a customer with utility consolidated billing, the supplier then also has to sell the corresponding receivables to the utility at a discount. Because the POR provision in Section 16-118(c) is limited to customers with a demand of less than 400 kilowatts, this combination of utility consolidated billing with the purchase of receivables is therefore also limited to customers with a demand of less than 400 kilowatts.

Ameren Illinois filed tariffs in September 2008 to effectuate the offering of a combined UCB/POR service per Sections 16-118(c) and (d) of the Act. The Commission approved Ameren Illinois's modified tariffs in August 2009 and UCB/POR service was available to suppliers in Ameren Illinois' service territory in October 2009. ComEd filed its tariffs in January 2010, offering a combined purchase of receivables with consolidated billing service and the Commission approved ComEd's modified tariffs in December 2010. As of May 31, 2013, 16 suppliers were using Ameren's UCB/POR service for residential customers (up from seven a year earlier) and 19 suppliers were using UCB/POR for non-residential customers (up from eight a year ago). As for ComEd, as of May 31, 2013, 41 suppliers were using ComEd's UCB/POR service for residential customers (up from 26 at the time of this report last year) and the same number of suppliers were using UCB/POR service for non-residential customers (up from 25 last year).

According to ComEd's second annual report on the usage of its UCB/POR offering, close to nine million utility consolidated bills have been issued in calendar year 2012 alone. This compares to about one million utility consolidated bills issued in calendar year 2011. Given ComEd's $0.50 per bill charge to suppliers for using this option, close to $4.5 million in revenues have been collected from participating suppliers in 2012. More than $450 million in total discounted receivables have been purchased by ComEd during this time period (up from about $61 million in calendar year 2011), with an average amount of $51 per purchased monthly receivables.

While virtually all suppliers are currently using UCB/POR for their residential customers, it is worth noting the widespread use of UCB/POR in the non-residential classes as well. By reviewing ComEd's monthly data, we are able to compare the number of new UCB/POR customers in a particular customer class to the number of total new ARES customers for that customer class. Analyzing the June 2012 to May 2013 time period, it shows that suppliers are using UCB/POR for all non-residential customers for which it is available, meaning the Watt-Hour[15], the 0-100kW, and the 100-400kW customer class. For the Watt-Hour class, the ratio of new UCB/POR customers to total new ARES customers has generally been in the 80-90% range, with the ratio being over 100% in some months. A monthly ratio exceeding 100% means that existing ARES customers have been converted to utility-consolidated billing during that month. As of May 2013, more than half of all RES Watt-Hour customers are on UCB/POR. For the 0-100kW class, the ratio of new UCB/POR customers to total new ARES customers has generally been, with a couple of exceptions, 90% or higher, with the ratio exceeding 100% in a few months. As of May 2013, 62% of all RES customers with demand up to 100kW are on UCB/POR. Even for the 100-400kW class, usually considered medium-sized customers, more and more suppliers are using UCB/POR to serve those customers. As of May 2013, 11% of all RES customers with demand between 100 and 400kW are on UCB/POR, almost triple the percentage from a year earlier.

[15] The Watt-Hour class consists of small commercial customers for which no metering equipment or only watt-hour metering equipment is installed at the customer's premises. Generally, a customer in this supply group uses less than 2,000 kWh during a monthly billing period.

IV. Additional Consumer Protections and Education

A. PlugInIllinois.org

PluginIllinois.org is the Commission's electric choice education website aimed at providing residential and small commercial customers with a better understanding of their electric supply options. Public Act 97-0222, which became effective in July 2011, amended Section 16-117 of the Public Utilities Act, requiring the Commission to maintain a consumer education information program to help residential and small commercial customers understand their service options in a competitive electric services market. This legislation required the ORMD to review the existing consumer education information available and consider whether updates are necessary. As a result, the ORMD sought input from interested parties, including the suppliers, electric utilities, the Attorney General, and the Citizen's Utility Board, to further its review of the consumer education materials and possible proposed changes. Additionally, Public Act 97-0222 required Ameren Illinois and ComEd to include the PlugInIllinois.org internet address on its monthly bill. In May 2012, both ComEd and Ameren Illinois started sending out monthly bills with this new information. The law also requires all suppliers to provide the PlugInIllinois.org website address to residential and small commercial customers.

As a result of the feedback from the interested parties, in 2012 the ORMD implemented several updates to PluginIllinois.org. These changes include updated information about the Low Income Energy Assistance (LIHEAP) and Percentage of Income Payment Plan (PIPP) programs, and expanded information was added to better explain the residential real time pricing programs (RRTP) offered by both Ameren Illinois and ComEd.

With the continued growth in the number of communities passing referendums to implement opt-out aggregation programs, the ORMD streamlined the Municipal Aggregation List of Communities from two separate lists to one list. Previously, one list included communities that had passed a referendum but had not implemented an aggregation program and a second list included communities that had implemented an aggregation program. The list of communities that had implemented an aggregation program provided the name of the chosen supplier, the aggregation rate in cents/kWh, and the term of the contract. The ORMD combined the two lists to include all communities pursuing an opt-out aggregation program. The new Municipal Aggregation List now contains eight columns including the name of the community, the status of each community's aggregation program, the chosen supplier, the rate, the contract end date, possible termination fees, utility service area and referendum date. Additionally, a sort function was added to the list, allowing visitors to the website to sort by community name, status, supplier name, aggregation rate, contract end date, service area or referendum date.

The municipal aggregation FAQs remain on PluginIllinois.org and aim to answer basic questions for customers in communities pursuing aggregation, including what action a person must take in the case of either opt-in or opt- out programs in order to affirm their choice of energy supplier.

In December 2012, the ORMD updated the "Customer Complaint Statistics" in order to include a Complaint Summary. The Complaint Summary shows the total number and type of complaints received for each retail electric supplier over the last two years. The Complaint Summary provides a more detailed view of the number and types of informal complaints the Illinois Commerce Commission receives about each retail electric supplier. Additionally, starting with the February 2013 Complaint Scorecard, which ranks suppliers by their rate of complaints compared to the average rate of complaints for the entire residential market, the Scorecard went from three groupings of approximately equal size to five groupings, or "stars." The change from three stars to five stars was prompted by the growth in the number of suppliers serving residential customers. On the first Complaint Scorecard published in April 2012, there were 18 suppliers represented. The April 2013 Complaint Scorecard, however, ranks 36 suppliers with residential customers.

In addition to the recent updates to PluginIllinois.org, the ORMD maintains the Price to Compare information for customers of Ameren Illinois and ComEd. The Price to Compare for ComEd combines ComEd's Electric Supply Charge with the Transmission Services Charge to provide customers a price (in cents per kWh) to compare with ARES offers. Similar to ComEd, Ameren Illinois' Price to Compare combines Ameren Illinois's Electricity Supply Charges, including the Supply Cost Adjustment, with the Transmission Service Charge to come up with a price Ameren Illinois customers can compare to supplier offers.

The offer comparison matrix, available through the "Compare Offers Now" link, prompts customers to select their utility service area to see the suppliers' offers available in their area, and it allows them to compare the offers to their utility rate as well as to each other. For each offer posted, the offer comparison matrix displays the supplier's logo, which is also a link to the supplier's website, as well as the particular offer name, which links to further offer-specific information on the supplier's website. The offer comparison matrix lists the price in cents per kWh, any potential additional monthly fees, the term in months, any possible early termination fees, and a brief description of the offer. It also lists the offer's cost for monthly usage levels of 500, 1,000 and 1,500 kWh. Customers are also able to sort the offers by supplier, by price, or by the length of the term. As of June 11, 2013, there are 24 to 27 supplier offers for Ameren Illinois residential customers (depending on the Rate Zone) and 67 supplier offers for ComEd residential customers.

Since the ORMD added the offer comparison matrix to PluginIllinois.org in July 2011 there have not been major changes to the matrix, aside from regularly updating the utility price to compare information. However, the ORMD is exploring the feasibility of adding a push notification, or alert system, for new offers posted on PluginIllinois.org. Interested customers would enter the criteria for which they wish to receive text or email notifications such as new fixed supply offers below a certain rate or with a certain term length or new "green" offers posted on PluginIllinois.org.

B. Other regulatory activities

The Commission's final Order in the ComEd Government Aggregation Protocols ("Rate GAP") tariff investigation, Docket No. 11-0434, directed Staff to present its findings with respect to the Commission's rulemaking authority regarding additional municipal aggregation issues. Subsequently, Staff presented the Commission with a memo that finds that the Commission has authority to promulgate further rules. As a result, on July 31 2012, the Commission entered an order initiating the proceeding to develop rules regarding municipal aggregation and opened Docket No. 12-0456. The ORMD hosted several workshops throughout the months of September and October, 2012, and on November 1, 2012, Staff submitted a draft First Notice rule in Docket No. 12-0456. A large number of interested parties provided several rounds of comments and on June 26, 2013 the Administrative Law Judge issued a Proposed Order. The Proposed Order addresses a variety of topics, including certain requirements for the notices to be sent to eligible aggregation customers and protections for customers who have previously actively selected a RES offer on their own.

In August 2012 ComEd filed a petition with the Commission to implement a Peak Time Rebate (PTR) program pursuant to Articles IX and XVI of the Illinois Public Utilities Act. In its February 2013 Interim Order in Docket No. 12-0484, the Commission ordered the ORMD to initiate a workshop process to address issues related to ComEd's proposed PTR program. For example, the Commission stated that the issue of what information needs to be supplied to RESs is appropriate for discussion in the workshops.

The ORMD held the first workshop in April, 2013 and set a schedule of workshop dates to conclude in August 2013. The ORMD will file a report following the workshops, indicating whether these issues have been resolved and, if so, describing the resolution reached in the workshops. If a consensus on some items is not reached during the workshop process on these items, Staff's report will describe those issues and may contain a proposed schedule to address them.

In October 2012, the ORMD assumed the role of reviewing all ARES certification petitions and ABC license petitions. The ORMD's review consists of determining whether the ARES or ABC applicant meets the managerial and technical qualifications necessary to obtain the certificate/license from the Commission. Since October 2012, the ORMD has reviewed 11 ARES certificate applications and 51 ABC license applications.

In January 2013, Illinois Administrative Code Part 412 became effective. Part 412.190 states:

> Only power and energy service that includes power and energy purchased entirely separate and apart from the renewable portfolio standard requirement applicable to RES under Section 16-115D of the Act can be marketed as "green", "renewable energy" or "environmentally friendly".

The ORMD has previously raised the issue of further defining "green" products, particularly with respect to possibly adding a new column to the Offer Comparison Matrix on PluginIllinois.org to identify offers that meet such a new definition. The ORMD wants to revive discussions on this topic, which may include holding workshops and submitting recommendations to the Commission. One topic of discussion will be whether the Commission has the authority to promulgate additional rules on the subject of defining green or renewable offers.

V. Suggested Administrative and Legislative Action

As stated in last year's report, the ORMD believes the Commission's municipal aggregation rulemaking proceeding in Docket No. 12-0456 was, and continues to be, a great venue to provide all interested parties with an opportunity to present policy and legal issues surrounding municipal aggregation and to propose solutions to those issues. If however, for whatever reason, the rulemaking is not able to fully address all items that, in the ORMD's judgment, deserve resolution, the ORMD will work with interested parties and the General Assembly to resolve any remaining issues legislatively.

Attachment 8

ELECTRICITY MARKET REFORM: APPA'S JOURNEY DOWN THE WRONG PATH

April 16, 2009

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Executive Summary

Regional Transmission Organizations (RTOs), currently manage much of the United States transmission system and provide reliable electricity service to more than two thirds of the nation's electricity consumers. Most RTOs also run day-ahead and real-time electricity markets to support reliable operations and capacity markets to support adequate investments; parties use the markets to buy and sell a variety of products and services. Those markets have evolved over time. The market model used in most of the United States is sound and has been endorsed by the International Energy Agency.

Various critics, including the American Public Power Association (APPA), propose major changes to RTO markets, but their reforms move in the wrong direction. The critics do not acknowledge the special characteristics of electricity that underpin these markets or the experience that led to the current designs. The markets should not be replaced in favor of discarded or untested alternative market models that ignore the many lessons we have already learned.

Proposals to unravel this successful market model threaten the investment required to maintain system reliability and promise to complicate the ability of independent market monitors to police against anti-competitive behavior and potential manipulation. Further, expectations that alternatives to this market model will result in lower prices for consumers are illusory. Rather, inconsistent and untested alternative market designs could cost consumers billions of dollars.

In the February 2009 publication, *Competitive Market Plan*, APPA offers another version of its evolving proposals to restructure organized electricity markets. The latest *Plan* follows APPA's *Consumers in Peril* (February 2008) and related papers maintaining that RTO markets cause electricity prices to be too high and do not lead to sufficient investments in new generation and transmission. But APPA's analyses are at odds with experience and reflect misunderstandings of how the RTOs and electricity markets work. The evidence shows that RTO market prices are not too high, and the studies APPA cites do not support a conclusion that the costs of RTO markets exceed the benefits they provide. Indeed the relevant evidence, much of it ignored by APPA, shows substantial benefits from RTO market design so obvious they appear to be "invisible in plain sight." (Appendix A)

Central to RTO markets are bid-based auctions, and a thrust of APPA's reforms is to limit or discourage use of these RTO auctions and instead somehow compel electricity suppliers (generators) to offer better contract terms to utilities and other load-serving entities (LSEs). There is nothing wrong with having long-term contracts, and RTOs are purposely structured to support voluntary contracting.

There is no evidence that contracting is failing in, let alone because of, RTO markets. Most of the trading done in RTOs today is through contracts easily accommodated by the RTO. But APPA asserts that suppliers will not contract at terms APPA deems acceptable because RTO markets offer too many choices. Much of the APPA critique flows from this premise. That buyers seek lower prices is neither unusual nor surprising. But this premise is hardly a sound basis for revising public policy.

The Proposal: Limit Spot Markets, Impose Long-term Contracts on Better Terms

Despite the unsupported diagnosis, APPA has proposed, in varying forms, two types of reforms; one to limit spot markets and another to impose long-term contracts on "better" terms. The details keep changing, sometimes in contradictory ways, and often in ways that would undermine how the RTO must operate the electricity system both to maintain reliability and provide all parties with open, non-discriminatory access to the transmission grid. Keeping the lights on at the lowest cost is an RTO's core function, and doing it while providing parties non-discriminatory grid access is a Federal mandate.

First, APPA seeks to prevent parties from relying too much on RTO spot markets. Under today's rules, parties are free to use RTO markets as much or as little as they want or need. Parties can contract to cover their loads and use RTO spot markets to deal with imbalances, or they can use RTO spot markets to supply their loads, or they can use a combination of contracting and spot market transactions. Parties are free to determine the mix between contracting and spot transactions. APPA would somehow restrict that choice, attempting to compel all parties to rely heavily on bilateral contracts.

To accomplish this, APPA would seek to artificially suppress spot market prices. The RTOs organize bid-based day-ahead and real-time spot markets to dispatch generation and ensure reliable operations. APPA would replace these with a real-time "optimization market" and some unspecified means for dealing with day-ahead commitments. In the latest version (*Competitive Market Plan*), supplier participation in the "optimization market" would be mandatory; all generators would be required to submit supply offers to the RTO for the real time optimization market at prices approved in advance by the RTO market monitors. Offer prices would be individually set at an estimate of short-run marginal costs. The proposal would essentially re-regulate all generation on a less-than-cost-of-service basis.

The first effect, and apparent hope, is that spot prices would be artificially suppressed. But unintended consequences would undermine short-run reliability and long-run resource adequacy. Suppressing spot prices would reduce incentives for resources to be available during shortages and keep total revenues below levels needed for adequate investment.

Second, APPA would require the RTO to implement (impose) a requirement that LSEs and suppliers trade almost exclusively through contracts, preferably long term, to cover any loads not met by the LSEs' own generation. The mandate for forward contracts would then buttress the goal of limiting use of the RTO spot markets.

APPA is silent on how the RTO would enforce this regime. Somehow, LSEs would be required not to plan on RTO spot markets to meet any portion of their needs except for inadvertent imbalances, even when spot market prices seemed attractive. And somehow suppliers would be compelled to contract with LSEs at terms the LSEs preferred. How this would be achieved is not explained. If everyone had been compelled to sign contracts at the higher prices existing a year ago, would this have been better than taking advantage of lower spot prices that exist today?

The Unfinished Evolution in APPA's Reforms

The preferred contracting framework has undergone significant evolution since *Consumers in Peril*. In one sense, such an evolution might be viewed as progress as the APPA confronts the realities of electricity systems that others have learned and embodied in the current RTO market design. However, a continuing missing chapter in the APPA analysis is any forthright description of the special characteristics of electricity systems that underpin the current RTO market structure. The several elements of bid-based auctions, economic dispatch, security constraints, locational prices, unit commitment, long-term contracts and capacity markets all work together to solve the complicated coordination problems that come hand-in-hand with an integrated transmission grid. The RTO market design elements are there for a good reason, and the lessons about missing pieces were learned at great cost. The APPA continues to sidestep the issues or give new labels to old ideas ("optimization market") that obscure the message and ignore the lessons of the past.

For example, in its early version, and in a November 2008 article in the *Energy Law Journal*, APPA officials described a market design best described as "contract scheduling." The model has a history, and it is not encouraging. With its limits on spot markets, the contract-scheduling model contains features originally proposed by Enron and others in the initial restructuring debates in California, PJM and New York. Early experiments with these features turned out to be costly policy mistakes, as we describe in Appendix C.

The contract-scheduling model is also familiar in non-RTO regions. It describes how utilities operate the transmission system where there is no independent RTO. The utility system operators are not required to use their ability to redispatch generation to provide third parties the same, non-discriminatory access to the transmission grid they provide to themselves. Most notably, third parties do not have equivalent access to economic dispatch.

The core features of contract scheduling are limited access to the dispatch (and related spot market) and requirements to obtain physical transmission rights to match bilateral contract schedules. These features have been shown to reduce grid utilization while increasing the risks of schedule curtailments. That means less economic trading across the grid and thus higher costs. A separate study performed by Ventyx (Appendix E), estimates that such restrictions, if implemented, could increase PJM customers' energy costs by about $13 billion over the next decade.

Moreover, the regions with limited spot market access and the contract-scheduling framework generally involve large vertically integrated utilities that operate the transmission system. This is key to making this model work, in that one entity owns the generation and transmission, provides ancillary services, and controls the dispatch. Recreating this framework in RTO regions would be extremely costly because RTOs *do not own or control generation*, and if bid based markets were constrained then the RTO (or delivery utilities) would have to acquire or contract with multiple generators in order to obtain scheduling rights to be able to operate the system reliably. We estimate (Appendix D) that the cost of reacquiring previously divested capacity for this purpose would cost utilities in the PJM region as much as $130 billion.

Most RTOs abandoned this approach (limited spot markets, physical rights, contract-scheduling) years ago. The superior approach used in RTOs today makes their bid-based spot markets and associated dispatch open to all parties on a non-discriminatory basis. Parties rely on the dispatch for balancing and use the open spot market to buy and sell energy to any degree they find beneficial. The RTO arranges the dispatch to keep the system balanced at the lowest as-bid cost; it adjusts the dispatch at the lowest as-bid cost to change electricity flows to manage congestion, so that no transmission line exceeds safe operating limits.

APPA's Formula for Shortages

Parties naturally tend to sign forward contracts at prices that reflect their expectations of what spot prices would be over the forward period. Deliberately suppressing spot market prices would logically lead to suppressed contract prices as well. That is apparently what APPA hopes. But suppressed spot prices plus suppressed contract prices add up to shortages, because potential supply investors would have no way to recover sufficient market revenues to support the level of supply investment needed to meet regional reliability (reserve margins) requirements. And APPA doesn't have a solution to that problem except to assume the RTO will fix it. But what options would the RTO have to ensure adequate supply?

A major goal of RTO market critics, especially APPA, has been to eliminate the RTO capacity markets and the associated requirement that LSEs make capacity payments to generators. Such payments provide revenue to generators to cover their investment costs and supplement energy market prices. If market prices are suppressed, and capacity payments are eliminated, then we have an investment problem, which will eventually become a shortage or reliability problem. On this point, APPA is sticking its head in the sand. The APPA reforms would not achieve the stated APPA objectives, much less achieve an improvement in RTO market design.

Most RTOs use capacity markets and payments because (among other reasons) their energy market rules prevent spot prices from reflecting scarcity costs when resources are short of desired reserve levels, as may happen a few hours each year. The problem is not that spot energy prices are too high, as APPA contends, but that they *are too low when the system is short of resources*. The "missing money" must be recovered in some fashion in order to provide the total revenues needed to support the desired investment level. That is the function of capacity markets in RTO regions. The same need to recover full investment revenue requirements would also apply in a fully regulated, cost-of-service regime.

APPA's Unworkable Framework: The Wrong Path Again

Altogether, APPA's proposals would create an unworkable framework and impossible dilemma for RTOs and the regions they serve. Spot market prices would be suppressed, reducing incentives for generators and demand-side response to be available when most needed. Spot prices would be even further below levels needed to support investments. Contract prices would also tend to be suppressed, but if not, the RTO would somehow force prices to levels acceptable to APPA members, while capacity payments were eliminated. Yet despite suppressed market prices, somehow investors could be persuaded to build enough capacity to meet the regional reliability standards.

The math doesn't add up, and the formula would lead eventually to shortages and necessary discriminatory rules. Once this became apparent, we would need to return to better spot pricing to improve incentives and encourage contracts, and probably some form of capacity payment to achieve the desired investment levels. But APPA proposals work against the direction of improving spot markets and providing improved incentives for real-time availability, long-run investments and energy efficiency that RTOs need and are developing.

The APPA analysis is internally inconsistent, and its proposals disconnected from the real requirements of operating electricity systems. As the accompanying paper demonstrates in detail, the APPA proposals point down the wrong path, again.

ELECTRICITY MARKET REFORM: APPA'S JOURNEY DOWN THE WRONG PATH

John D. Chandley and William W. Hogan[1]

I. Introduction

Beginning with the Energy Policy Act of 1992, the United States undertook an intense period of experimentation and regulatory innovation to restructure electricity systems.[1] Repeated policy reviews and supporting legislation have reinforced this process.[2] As part of this restructuring, the US developed widespread organized electricity markets coordinated by Regional Transmission Organizations (RTOs).[3]

RTOs now reliably serve over two thirds of US electricity consumers. But they are under attack by critics who argue that RTO markets are causing or enabling higher electricity prices and that the way to force lower prices is to substantially reduce RTO market functions. The American Public Power Association (APPA) and other early market supporters have called for major reforms of RTO-organized markets. Here we examine their key proposals.

The critics write that RTO markets are not working as anticipated and do not produce prices consistent with "just and reasonable rates." These concerns have intensified in recent years as electricity prices rose, against unrealistic expectations that markets alone would lead to lower prices even if the industry's underlying cost structure was rising. But during this period, prices were rising nationwide, in RTO and non-RTO regions alike, because of rising costs of the coal and natural gas that power a majority of US generating capacity. In many US regions, coal and gas-fired resources are often the marginal units that determine market-clearing wholesale prices. Costs for basic construction materials and equipment also increased markedly.[4]

APPA's main criticism focuses on RTO bid-based auctions for buying and selling power. The RTOs operate hourly spot markets for energy and ancillary services (such as operating reserves) which select the lowest-cost plants to keep the lights on, and forward capacity markets that help pay for adequate resources. The claim is that spot prices are too high, capacity payments are unwarranted, and suppliers are exercising market power.

A. The APPA's Search for RTO Reforms Has Been on the Wrong Path

The critics' reforms wrongly target RTO markets without acknowledging what these markets do or why they are needed. It is beyond dispute that electricity systems require central coordination to keep the lights on. RTOs use bid-based markets to select the lowest-cost resources to perform these coordina-

1 William W. Hogan, "Electricity Market Restructuring: Reforms of Reforms," (hereafter "Reforms of Reforms"), Journal of Regulatory Economics, Kluwer Academic Publishers, Vol. 21, No. 1, 2002, pp. 103-132.

2 Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

3 Prior to 1996, the US grid was operated by publicly and privately owned electric utilities and federal power marketing agencies. Closely interconnected utilities sometimes "pooled" their operations, allowing a central regional power pool to operate the interconnected systems as one system. For example, the PJM power pool was created in 1927 to operate the combined grids and dispatch generation for member utilities in Pennsylvania, New Jersey, Maryland (hence "PJM") as well as Delaware and the District of Columbia. PJM became an "Independent System Operator" (ISO) in 1997 and began coordinated market operations then. After 2000, the Federal Energy Regulatory Commission (FERC) redesignated several ISOs—PJM, ISO New England (ISO-NE), Midwest ISO (MISO)—as RTOs. Essentially similar organizations now include the New York ISO (NYISO), California ISO, the Southwest Power Pool (now an RTO), and ERCOT (an ISO covering most of Texas but not subject to FERC jurisdiction). Each coordinates organized markets with many of the features of a regional power pool. For simplicity, we refer to all such markets as being administered by an RTO, even though some of the markets are actually administered by ISOs rather than RTOs.

4 In the mid-1990s, state restructuring decisions froze retail rates for a transition period. When the transition periods expired in recent years, retail rates had to be adjusted to reflect current (higher) wholesale market prices facing utilities and other load-serving entities (LSEs).

tion functions. Faced with the need to provide both this coordination and non-discriminatory access to the electricity grid, RTOs must operate under a market design that is internally consistent and compatible with the special technical features of the electricity system. Eliminating the RTO coordinated markets would make the necessary coordination function more difficult and expensive, while creating a need to invent solutions to solve the coordination problems.

Predictably, the critics' redesign proposals vary widely, but because the new solutions are often unworkable, they keep changing, suggesting an evolving, incomplete appreciation of how RTOs must function. The result has been a series of *ad hoc* proposals that often resurrect flawed approaches that have already been considered and rejected, or tried and failed.

APPA's latest *Competitive Market Plan* proposal[5] reflects this continuing *ad hoc* search for a workable redesign. Beginning with the publication, *Consumers in Peril* [6] and continuing with an article in the Energy Law Journa,[7] APPA officials argue for a redesign of RTO-coordinated electricity markets, dismantling some markets, restricting others, and forcing parties into contract arrangements they claim the RTO markets do not support. With its *Competitive Market Plan*, a hopeful evolution is apparent, but it is not complete; a coherent framework that recognizes what RTOs must do and why is still missing. Also missing is the realization that its proposed reforms would not achieve APPA's expressed goals.

In *Consumers in Peril*, APPA acknowledged important transmission benefits provided by RTOs but argued these benefits do not exceed RTO costs. We examine these claims in Appendix A and show how they misread cost/benefit studies and ignore quantitative and qualitative empirical evidence of benefits provided by RTOs.

The *Consumers* paper called for the elimination of current bid-based RTO spot markets. These would be replaced by restricted access (no more than 5 percent of load) to a limited, residual balancing market. But the discussion left unclear how the reliability-related functions of these spot markets would be performed. Indeed, it is doubtful that the vaguely defined framework APPA proposed in *Consumers in Peril* would have allowed RTOs to perform the most basic functions of keeping the lights on, let alone supporting a viable electricity market.

APPA promised further details, and the November 2009 *Kelly/Caplan* article included proposals to implement APPA's intentions, offering a "hybrid" design the authors dubbed "Day 1.5 RTO."[8] (Current RTO designs are called "Day 2 RTO.") However, the Day 1.5 RTO model actually described a pre-RTO market design familiar to those in non-RTO regions and included features that were tried and failed in the 1996-2001 period in California and elsewhere. That design, which we call a "contract-scheduling" model, would probably have required the dissolution of RTOs and regional grid operators (power pools), forcing a reversion to utility-by-utility dispatch to sustain reliable operations.

It is important to understand how APPA's earlier proposed contract-scheduling model would have functioned, so we devote Chapter IV and related Appendices to explaining its features, costs and disadvantages. While APPA has now moved to yet another proposal, there are still remnants of this flawed approach in the most recent *Competitive Market Plan*. Returning to that framework, once advocated by Enron and partly implemented at great cost in California (see Appendix C), would be a serious policy mistake.

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5 APPA, *Competitive Market Plan*, February 2009.

6 APPA, *Consumers in Peril*, February 2008; available at http://www.appanet.org/pressroom/index.cfm?ItemNumber=18029&sn.ItemNumber=16668. Similar critiques come from Electricity Consumers Resource Council (ELCON) available at www.elcon.org.

7 Susan Kelly and Elise Caplan, *Time for a Day 1.5 Market: A Proposal to Reform RTO-Centralized Wholesale Electricity Markets*, 29 *Energy Law Journal* 491 (2008). Kelly is APPA's Vice President of Policy Analysis and General Counsel and Caplan is the Coordinator of APPA's Electric Market Reform Initiative, but the authors state at 491: "All statements in the article, however, are the authors' alone and should not be attributed to the APPA." This article is hereafter referred to as *"Kelly/Caplan"* and the revised proposal is the "Day 1.5" proposal. In *Consumers in Peril*, APPA promised further details, but *Kelly/Caplan* has now been superseded by yet another proposal.

8 *Kelly/Caplan* at 533.

In the contract-scheduling model, parties would be required to secure owned generation and/or forward contracts to cover their entire load and demonstrate the sufficiency of those plans in advance to the RTO.[9] Parties would then gain access to the transmission grid by obtaining rights to schedule their own generation and contract deliveries with the RTO, but without the flexibility provided by the RTO spot markets in facilitating those schedules.[10]

Forcing such schedules and limiting planned access to the balancing market implies some form of physical transmission rights, instead of the financial rights used by RTOs today. While *Kelly/Caplan* alluded to the transitional problems,[11] the preferred approach was a transmission access scheme that would revert to a system of physical transmission rights in which parties would reserve physical capacity on specific transmission lines to match their desired schedules. RTOs largely abandoned the physical rights approach years ago, because it does not account for actual power flows and thus requires subsequent curtailments to maintain reliability. Under the APPA framework, the RTO's current system of "financial transmission rights," which do not require physical reservations but do account for actual flows, would be phased out.[12]

A contract scheduling approach with physical transmission rights would be a costly step backwards. As we illustrate in the Appendices, just to perform the essential dispatch function, the design would have required at least some utilities to reacquire — at an estimated cost of $130 billion — generating capacity they divested a decade ago. In addition, the contract-scheduling model would have reduced inter-area trading, making transactions less likely or more costly, thus increasing costs to consumers by another $13.6 billion over a decade.

B. APPA's Evolving *Competitive Market Plan* Is Still Seriously Flawed

In its latest proposal, *Competitive Market Plan*, APPA has abandoned (for now) portions of the earlier approach, particularly its formal reliance on physical transmission rights. Financial transmission rights (FTRs) would be preserved. Other elements of the contract-schedule model are retained, such as the requirement that LSEs secure advance RTO approval for each LSE's plans to serve its load through owned generation and/or bilateral contracts.[13] The new *Plan* does not explain what would occur if all requested generation were not simultaneously deliverable to all loads given current transmission limits. But these are the details that matter and that help determine the current RTO design.

Once again, planned reliance on the spot market is forbidden, even though the spot market would be available in real time for unplanned imbalances. Inevitably, limiting access to the spot market would lead to resurrecting the associated contract scheduling requirements.

A consistent APPA goal has been "to deemphasize the role of RTO-run centralized power supply markets and provide support for a stronger bilateral power supply contracting regime."[14] These goals then translate into forcing load serving entities (LSEs) and power suppliers to rely almost exclusively on bilateral contracts while restricting their option to use the RTO auction-based spot markets to buy and sell power. There would be a limited "balancing market," (which *Competitive Market Plan* calls an "optimization market") while today's day-ahead and real-time bid-based spot markets would be phased out.[15]

APPA's "optimization market" would perform system-wide central dispatch, arrange and pay for ancillary services (*e.g.* operating reserves), and provide balancing for parties' schedules. Importantly, this optimization market retains certain core functions found in the RTO real-time spot market: security-

9 APPA retains this feature in *Competitive Market Plan* at 27.
10 *Kelly/Caplan* at 539.
11 *Consumers in Peril* at 27. *Kelly/Caplan* at 534, footnote 204.
12 *Kelly/Caplan* at 534, footnote 204, 535.
13 *Competitive Market Plan* at 4.
14 *Kelly/Caplan* at 491.
15 *Kelly/Caplan* at 535, 539.

constrained economic dispatch, clearing prices ("for the near future") based on locational marginal pricing (LMP)[16] and FTRs to help offset congestion costs. These are essential features for a real-time spot market, but then APPA compromises them without explanation. Thus, while there is a partial evolution away from the flawed contract scheduling design, there are still troubling departures from how today's markets function; if implemented, these departures would prove to be unworkable and even exacerbate the problems APPA claims to be solving.

For example, APPA's *Plan* would force suppliers to reveal and the RTO to use a simplified statement of each generator's short-run marginal costs (SRMC). Without explaining how, these SRMCs would be individually verified and continuously updated by the RTO's Market Monitors.[17] Mandatory participation would be enforced by a must-offer requirement.[18] The RTO would then be required to use these SRMC estimates as the basis for dispatch and associated optimization market pricing.

With some exceptions, all generators would be required to participate in the RTO dispatch/optimization market. This is a form of "mandatory pool," a model that hasn't been mentioned since the early California debates on market design. When combined with the forced use of SRMC, the approach is analogous to how vertically integrated utilities conduct a dispatch when they own all of the generation and dispatch is based on internal company information. It is not an exaggeration, therefore, to describe this approach as akin to detailed less-than-cost-of-service regulation.

Another serious concern is APPA's proposal to prohibit generators (and the RTO) from considering a generator's opportunity costs — *e.g.*, what a supplier could receive from selling into a neighboring market — as a basis for dispatch and spot market participation.[19] Recognition of opportunity costs is standard, textbook economics, and prohibiting any supplier from using opportunity costs would result in distorted incentives and suppressed market prices. These features would encourage withholding or discourage generators and demand-side responses from being available when most needed.

The suppressed prices would also undermine investment. Indeed, by suppressing spot prices, the prohibition would exacerbate the "missing money" problem that currently serves to justify capacity markets, which APPA also seeks to eliminate.

Yet another problem with APPA's *ad hoc* "optimization market" design is that it would not actually optimize the RTO's decisions about which generators should be dispatched for energy and which held as operating reserves. Getting that right requires that each set be paid clearing prices for each service provided, so that the prices both minimize the RTO's total costs and maximize value to each provider. Each provider then has the incentive to follow the RTO's instructions, and no generator regrets being told to provide reserves instead of energy (or the reverse). The APPA mistake is proposing to pay generators at cost to provide reserves, rather than a clearing price optimized between energy and operating reserves.[20] This design error would distort incentives to follow dispatch instructions and encourage reserve shortages.

16 APPA obscures the fact that its *Plan* retains Locational Marginal Pricing (LMP), which APPA disparaged in *Consumers in Peril* and *Kelly/Caplan*. In *Competitive Market Plan*, the term "LMP" is never mentioned, but the *Plan* states: "RTOs would continue to provide transmission service under open access transmission tariffs (OATTs), dispatch generating units in merit (lowest cost) order subject to system constraints, *determine price differentials arising from congestion*, and assist LSEs in hedging congestion." (emphasis added) *Competitive Market Plan* at 29. In today's RTOs, LMP spot prices reflect price differentials arising from the dispatch to deal with congestion. Similarly, APPA's "optimization market" is in fact a real-time spot market, which APPA previously sought to eliminate. To improve the dialogue, it would be helpful if APPA would use the terms everyone else uses, and simply acknowledge that RTO elements it once criticized are in fact essential and must be retained.

17 APPA concedes that it would be difficult for the RTO to maintain an accurate, up-to-date analysis of every generator's SRMC, as fuel and other cost components varied daily. APPA merely assumes the RTO could solve this without explaining how. Yet this is a principal reason why RTO pricing rules create strong incentives for the generators themselves to determine, and bid, their marginal costs. Today, RTO Market Monitors set SRMC-based limits on supply offers only in those situations in which market power might be expected. This more manageable approach gives the RTO reasonable assurance that offers will tend to track actual SRMC and/or opportunity costs, without requiring the RTO to track and verify every possible component and change in every generator's cost structure.

18 *Competitive Market Plan* at 25, 27.

19 *Competitive Market Plan* at 25.

20 *Competitive Market Plan* at 28.

Another misguided reform relates to FTRs. While retaining FTRs (and giving up on a return to physical rights for now), APPA would complicate the task of allocating FTRs to grid users. APPA would eliminate the RTO's monthly and annual FTR auctions by which short- and long-term FTRs are currently allocated and traded. Instead, the RTO would simply allocate FTRs to LSEs annually, giving a preference (without any apparent justification) to those with long-term contracts.[21] This would seem to favor APPA members who do not own transmission, but the details are missing and the intent is not clear.

Eliminating periodic FTR auctions is consistent with APPA's general opposition to "bid-based markets," but just as APPA now concedes the RTO must have a real-time spot market (renamed "optimization market") it would eventually discover the RTOs also need periodic FTR auctions. No RTO began with such auctions, but every RTO and their members eventually concluded such auctions were worthwhile.

In the meantime, eliminating the current FTR auctions would leave unanswered how the RTO would solve the problems these auctions address. For one thing, the auctions are a simple, proven way for parties to acquire FTRs, to exchange those they have for ones they'd prefer, and to exchange them with other parties. That is why many commodity markets create central exchanges.

The auctions also solve the difficult problem of deciding how many FTRs to allocate, and which ones. The grid cannot support an unlimited number of FTRs, nor can it support a condition in which all the requested FTRs are between the most preferred grid locations. While noting that the RTO would have to confirm the simultaneous feasibility of any FTR allocation requests,[22] APPA does not explain how the RTO would solve the problem if, as frequently occurs, LSE requests for FTRs were not simultaneously feasible.

Today's RTOs use periodic FTR auctions to solve the feasibility problem. Each auction allocates that period's FTRs to those who value them the most, up to the limits of simultaneous feasibility, but no further. The auction winners receive a set of FTRs that are simultaneously feasible. Auction revenues then revert to those who pay the grid's embedded costs, a solution most parties agree is fair and workable. Without explanation, APPA would eliminate these useful auctions without offering any alternative means to implement their functions.

APPA's proposals appear to be still evolving. So these and other spot market design errors in *Competitive Market Plan* might be cured as APPA continues to work through the reasons why RTOs do what they do. But there are more fundamental problems with APPA's approach to forward contracting and APPA's unrealistic expectations about eliminating the need for capacity payments (or some other solution) to solve the "missing money" problem. We examine these issues next.

21 *Competitive Market Plan* at 29-31.
22 *Competitive Market Plan* at 31.

II. Effective Contracts Require A Consistent Market Design

APPA's *Competitive Market Plan* continues its goal of forcing virtually all trading into (preferably long-term) bilateral contracts and self-owned generation.[23] There are numerous problems with this coerced approach, starting with the point that there is nothing prohibiting suppliers and LSEs from contracting today, for whatever period they choose and at whatever price they agree. Hence, the problem is not contracting *per se*.

Long-term contracts can be and are an important part of the electricity market. However, effective contracts depend on a market design that is both internally consistent and reflects the essential features of the electricity system. The APPA discussion of the role of contracts and their connections to the remainder of the market illustrates the critical missing chapter in its critiques. There is no coherent diagnosis of how the electricity system works or how the pieces fit together.

APPA's complaint is not that bilateral contracts aren't possible and fully accommodated by today's RTOs — they are used extensively in today's RTOs, as APPA concedes[24] — but rather that suppliers won't agree to terms APPA's members prefer. APPA claims this is because suppliers can always sell into RTO spot markets, and spot prices are inflated by excessive supplier offers setting the clearing prices. But RTO Market Monitors have periodically evaluated and rejected these claims,[25] and FERC has agreed.

APPA further claims that suppliers are unreasonably demanding that contract prices reflect expectations of future spot market prices and related risks.[26] But this connection between contracts and expected spot prices over the life of the contract is an expected feature of properly functioning markets. Rather than being evidence of failure of the market design, the connection between contracts and spot markets is a sign that the RTO markets are functioning as designed.

APPA rejects this well-understood logic. It insists on breaking the logical link between expected spot and forward contract prices, without considering the poor incentive effects this would have on parties' contracting or dispatch behavior.

A persistent priority of RTO market critics has been to constrain or discontinue RTO "centralized bid-based locational capacity markets." In the evolving APPA proposals, these capacity markets would be replaced by a vaguely defined capacity resource planning and acquisition scheme involving LSEs, state regulators and the RTO. Regional planning is desirable, and RTOs currently coordinate it, so there is little new here. At the end of its process, APPA claims, LSEs would ultimately build their own capacity or acquire it under contract (just as they can do today), but there would be no RTO-coordinated auctions for buying and selling capacity.[27]

It is here that the APPA bilateral contracting structure starts to break down, with APPA making several

23 *Competitive Market Plan* at 19-21.

24 APPA notes in *Competitive Market Plan*, at 21, that the vast amount of trading in RTOs already occurs through bilateral contracts. In PJM, it's 96 percent and varies in other markets. Note that the RTOs do not (because they have little need to) track all bilateral contracting; most contracting occurs between the parties without the RTO's knowledge, even though both may be buying and selling through the RTO spot markets, while settling net differences between themselves. Thus, rather than limiting bilateral contracting, the RTO spot markets appear to be fostering and accommodating massive bilateral trading.

25 See, *e.g.*, PJM's *2007 State of the Market Report*, available at www.pjm.com One such finding states: "The overall results support the conclusion that prices in PJM are set, on average, by generating units operating at or close to their marginal costs. This outcome is strong evidence of competitive behavior." PJM press release, March 11, 2008, accompanying release of the 2007 Report. More recently, the *2008 State of the Market Report*, at 2, summarizes the Market Monitor's findings: "The MMU concludes that in 2008: *The Energy Market results were competititive; *The Capacity Market results were competitive; *The Regulation market results cannot be determined to have been competitive or to have been noncompetitive; *The Synchronized Reserve Markets' results were competitive; *The Day Ahead Scheduling Reserve Market results were competitive; and *The FTR Auction Market results were competitive."

26 *Competitive Market Plan* at 19.

27 *Kelly/Caplan* at 535.

simultaneous but incompatible assumptions. APPA seems to assume that the RTO can force generators to accept suppressed prices in the spot market and lower contract prices, while *at the same time* supply investors agree, independent of these prices, to build the amount of capacity the RTO sets as the resource adequacy goal. And investors will do this even though the structure does not provide capacity payments to make up for the suppressed spot and contract revenues and even though the market prices fail to provide price signals about the need for investments. There is no workable business or economic model to match this set of inconsistent expectations, unless it is premised on confiscation.

So how could it all work? APPA leaves that important question unanswered, essentially assigning to the RTO the task of "implementing" the proposed resource adequacy framework but without the ability to set spot prices sufficient to support the required level of investments or to use capacity payments to make up the difference.[28]

Today's RTOs could solve the problem either by allowing spot prices to reflect scarcity — prices are capped below that level today — or by supplying the "missing money" through capacity payments, or more likely, some combination balancing the two. But APPA leaves RTOs with the unresolved investment problem while prohibiting the logical solutions, which means the entire framework is unworkable.

The flaws and inconsistencies in the APPA analysis appear in related ways such as confusing the distinction between prices and costs, breaking the logical link between spot and forward markets, and failing to confront the real challenges of long-run resource adequacy and its costs.

A. Confusing Prices and Costs

The APPA analysis discusses several different measures of price and relates these to its view of costs under traditional regulation. In some discussions, "prices" refer to spot prices for energy: "The prices for electric power in these centralized markets are set at specified intervals (every hour or a given time interval within an hour) based on the offers to sell power submitted by generation owners, operators and marketers to the RTO." [29] In other contexts the reference is to retail prices which include the payments for energy and ancillary services as well as the capacity payments required by resource adequacy programs: "Restructured wholesale markets are producing both higher prices and higher profits than one would expect in a competitive market. Resulting retail prices exceed those prevailing in regions that have not restructured, but that instead retained traditional retail cost-of-service regulation and eschewed the formation of RTOs." [30]

Although prices were higher to begin with in regions that restructured, the argument is that prices are too high and would have been lower under cost-of-service regulation. However, that conclusion is based on posing the wrong question. And the conclusion for the correct question is more nuanced when we look at the performance of organized wholesale markets. In particular, and contrary to the critics' argument, the evidence indicates that a principal problem with RTOs is that spot market *energy* prices have been too low to support needed investment.

The critics' characterization of the theory for determining spot energy prices is only partly correct. "The RTO takes all power supply offers for a particular upcoming time interval in ascending price order, stopping with the last offer needed to meet the power needs of loads during that time interval." [31] Ignoring the effects of congestion, this is true during periods of excess capacity. Unfortunately, this rule does not establish the efficient price during periods of limited capacity and associated scarcity of generation offers.[32] During periods of scarcity, the market-clearing price should reflect the scarcity

28 *Competitive Market Plan* at 3.
29 *Kelly/Caplan* at 496 (footnote omitted).
30 *Kelly/Caplan* at 494.
31 *Kelly/Caplan* at 496.
32 William W. Hogan, "On An 'Energy Only' Electricity Market Design For Resource Adequacy," Harvard University, September 23, 2005, (www.whogan.com).

costs and clear at a sometimes (much) higher level. The higher energy revenues would be an important part of the contribution to recovery of the fixed costs of generation assets.

Compounding the difficulties, most RTO designs include features that preclude these sometimes higher prices. The lower prices result in the so-called "missing money" problem.[33] For a variety of reasons that include price caps, operating procedures and conceptual mistakes in translating theory into practice, energy prices in the electricity market have not been high enough to support investment in new generating plants.

For example, over the nine years from 1999 through 2007, the market monitor for PJM estimates that average energy market revenue under economic dispatch for a combustion turbine peaking unit was $16,401 per MW-year compared to an average fixed cost charge of a new unit of $75,158 per MW-year. The difference of $57,757 per MW-year is the missing money.

Estimates of expected net revenues going forward should be the proper benchmark, but this retrospective look at the actual revenues achieved net of variable costs is sobering and suggests a real problem in the underlying market design. There is inadequate attention to scarcity in spot energy prices, and spot market revenues are too low. The average net revenues were approximately 22 percent, 45 percent, and 63 percent of the levels needed to justify investment in a new combustion turbine, gas fired combined cycle or coal plant, respectively.[34]

The policy response has been to address the underinvestment and missing money problems by developing forward capacity markets. PJM's approach for providing these capacity payments, the Reliability Pricing Mechanism (RPM), receives much criticism from APPA and others.

In comparing market and cost-of-service paradigms, it is important to formulate the right question for evaluating prices. A comparison with cost-of-service rates presents the wrong question because it does not hold constant the allocation of risks. Implicit in the traditional regulated model is the assumption that customers bear the risk that the long-run cost of providing energy and other services will exceed the value of those services. Implicit in the restructured electricity model is a different allocation of risks, with the generators assuming the risk that the prices they receive for providing energy and other services will not be sufficient to cover the long-run costs of providing those services, unless they have entered into long-term contracts with buyers. Without controlling for these different risk allocations, and looking across the distribution of uncertain outcomes, there is not much of interest in the observation that under one set of conditions there is a price difference.

In evaluating the performance of RTOs and organized wholesale markets, the more relevant question is how the prices observed compare with the competitive outcome. Here the natural benchmark, particularly with growing demand, would be in the cost of new entry. If sustained prices were higher than needed to support the cost of new entry, there would be a cause for concern and we would be looking for the policy design flaws in RTOs that were preventing otherwise profitable entry. But in the present case the facts are reversed. Spot energy prices by themselves are too low to support entry, partially because the current RTO market designs give too little attention to the theoretical and practical requirements for better scarcity pricing.[35]

The resulting creation of capacity markets was intended to address the missing money problem and make up the net of the expected costs of entry to support new investment. The RTO critics seem well

33 The characterization as "missing money" comes from Roy Shanker. For example, see Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003.

34 PJM Market Monitoring Unit, *2007 State of the Market Report*, Volume 1: Introduction, Volume 2: Detailed Analysis, March 11, 2008, Tables 3-7 thru 3-9 (Vol. 2) & 1-3 (Vol. 1), respectively.

35 An additional contributor is that reliability requirements, such as 15 percent or higher reserve margins, may mandate the development of more capacity than is economic. The additional reserve capacity would tend to suppress the prices we observe in the spot markets below the levels required to induce entry even if those markets properly reflected scarcity.

aware that the costs of new entry are high and increasing: "Consumers are already very likely to face increased electricity prices in the coming years, given increasing infrastructure requirements, rising fuel and construction costs, and the need to comply with future carbon regulation." [36] However, the critics do not connect this reality to their analysis of the costs of capacity payments, the impacts on existing retail rates, or the evaluation of the performance of RTOs.

The implications of clarifying the question are straightforward and important. Spot energy prices should include scarcity costs and not be determined solely by the variable cost of the most expensive plant running. To the extent that spot energy prices are too low, there is an increase in the net capacity payment required to support new entry, and this higher capacity payment plays a greater role in determining retail prices.

B. Breaking the Logical Link Between Spot and Forward Markets

The varying APPA approaches target new rules for requiring forward bilateral contracts as a key ingredient in the program to change the operations of RTO markets. It is true that forward markets are important, and much of the RTO design is motivated by the intent to facilitate use of forward contracts struck between willing buyers and willing sellers.

The critique of the existing RTO markets implies that there is something wrong with the existing opportunities for forward contracting. Notably, the critics do not claim it is impossible to obtain forward contracts in the current markets. "Buyers and sellers in Day-Two markets can minimize purchases and sales of energy and capacity in the RTO-run markets by entering into individual power supply contracts (called 'bilateral contracts')."[37] Apparently, the problem is not the existence of contracts or contract counterparties; the problem is the price available.

> "But, the forward prices for energy sold under those contracts are substantially influenced by the prices the sellers can obtain for their power in the RTOs' centralized markets."[38]

> "A recent study which the APPA commissioned examining the relationship between RTO-run spot markets and bilateral contracting in RTO regions found that power supply transactions in the organized markets are dominated by the spot markets, even when much of the energy used to serve load is not directly procured through the RTO's spot markets."[39]

Given its critique of existing spot markets, APPA's implication is that there is a failure in forward contracting under reasonable terms and conditions.

It is for buyers and sellers to decide how much to transact under contract, at the price each is willing to accept. However, the RTO critics' analysis is not really a critique of the forward contracting opportunities under the RTO design. The analysis says little more than that customers would prefer to have contracts at lower prices. There is nothing in the analysis that translates into evidence of a failure of the RTO model to support forward contracts.

The observation that forward contracts are driven by expectations about future spot prices is fully in keeping with the economic theory underlying the RTO market design. It would be surprising if anything else were true in a market where buyers and sellers have a choice to contract or to rely on the spot market. In equilibrium, the natural forces of arbitrage should be enough to eliminate any risk-adjusted difference between new forward contracts and expected spot prices. This would be true for a competitive market, or for many other possible market structures that are not competitive.

36 *Kelly/Caplan* at 491.
37 *Kelly/Caplan* at 502.
38 *Kelly/Caplan* at 502.
39 *Kelly/Caplan* at 503.

However, the APPA approach anticipates breaking this logical connection between spot and forward markets. "This is consistent with the theory that sellers should be recovering their fixed costs (including return) through long-term bilateral contract arrangements, and not relying on short-term RTO market sales to recover such costs." [40] The main thrust of the contract-scheduling framework is to restrict choices, limit participation in spot markets and somehow mandate long-term contracts in order to create such a disconnect.

The forward and spot markets are both important. However, the observation that there is a linkage of prices between the two markets should not be construed as a failure of the RTO model. The linkage is part of the design, and a conclusion that the linkage is working should be interpreted as consistent with the design of the RTO markets. The critics' proposed structure would break something that isn't broken and that should be preserved.

40 *Kelly/Caplan* at 537.

III. APPA's Framework Would Not Reduce Long-Run Resource Adequacy Costs

Critics have voiced strong objections to RTO capacity markets, especially PJM's Reliability Pricing Mechanism (RPM). PJM market rules require each LSE to provide or purchase sufficient generating capacity to meet its share of the region's planning reserve requirement. PJM's RPM is one means to meet that requirement. But the requirement exists independent of RTOs and their capacity markets.

In the *Kelly/Caplan* article, and again in *Competitive Market Plan*, APPA proposes a different resource planning and acquisition framework for meeting the planning reserve requirement. That framework would do nothing to lower total electricity prices.

Under any framework, utilities and other LSEs must meet reliability standards set by their states and/or the regional entities responsible for setting those standards. In the PJM region, the standards currently require that each LSE own or purchase enough capacity to cover that LSE's expected peak loads plus a planning reserve margin of 15 percent or more.[41]

In PJM and other eastern RTOs, parties meet their reserve capacity obligations by building their own generation, purchasing capacity under bilateral contracts, or purchasing capacity in the RTO capacity markets. In PJM's capacity market (RPM), all capacity is accounted for in the annual capacity auctions; LSEs with capacity receive credit for the capacity they offer or self-supply; they are then paid the capacity market price for any surplus they offer beyond their own requirements, while paying the market price for any additional capacity they must purchase.

PJM's RPM forward auction framework defines the forward market value of capacity in each planning period, given the reserve target, the available resources and the offers/bids from auction participants. It also incorporates demand-side resources and transmission upgrades. Parties can use PJM's RPM auctions to meet their capacity obligations and to buy/sell capacity through means other than bilateral arrangements if they choose to do so.

LSEs are required to meet the mandatory capacity reserve requirements whether they function within PJM, whether PJM uses RPM or doesn't, or whether LSEs function as vertically integrated utilities outside an RTO framework. This means that for the same capacity reserve target, such as 15 percent reserve margins, the total costs of meeting the standards would likely be about the same under any structure.

To illustrate this point, Appendix F examines an alternative scenario that assumes PJM's RPM capacity market did not exist. Instead, each utility would be required to build or purchase sufficient generating capacity to meet its *pro rata* share of the mandatory capacity requirements. The comparison set forth in Appendix F illustrates that loads would have to pay essentially the same total costs in either case over time to acquire the same amount of capacity, because no matter what, the total costs associated with developing, maintaining and operating that capacity must still be paid. The assumption that eliminating PJM's RPM would reduce long-run resource adequacy costs is illusory.

The RTO critics call for an alternative process involving LSEs, generators, the RTO, state regulators and interested parties to determine the amount of capacity that should be developed. Each LSE would

41 The reliability standard is typically expressed to require sufficient capacity to ensure that the system will run short of capacity no more than one day (or one event) in 10 years. The one-day-in 10-year standard is then translated into an equivalent reserve margin for each system, which can vary depending on the reliability of transmission and generation available to that system. Systems with plants that suffer more frequent outages or more limited transmission import capacity must meet a higher installed reserve requirement; those with less frequent outages or greater import capability meet a lower installed reserve requirement.

then acquire the necessary capacity, except there would be no auction market operated by PJM where those with surplus capacity could sell it and those who needed capacity could buy it. At the end of this process, every LSE or utility would essentially self-supply its own or acquired capacity. PJM would play an expanded role in this planning process, with state regulators playing supporting roles. But even if states found this arrangement attractive, there are three observations worth noting.

First, if parties in the PJM region were enamored with APPA's approach, its results could be accommodated today within the PJM capacity market structure. In other words, states or utilities could undertake extensive integrated planning exercises, select the capacity resources they preferred and direct LSEs under their jurisdiction to build the resources or acquire the capacity through contracts. The LSEs could then offer that "self-supplied" capacity into PJM's RPM auction and receive credit towards meeting their PJM-regional capacity obligations. PJM's RPM construct accommodates self-supply.

Second, because LSEs/utilities can and do use this self-provision approach today to minimize net purchases through the PJM capacity markets, it is not correct to assume parties would save money over time by replacing the current PJM approach while retaining the same reserve requirement. All this would achieve would be to eliminate parties' ability to use RPM's periodic auctions to sell their excess capacity and purchase deficiencies to meet their respective requirements.

Third, this analysis implicitly assumes that it is possible to forecast each LSE's share of the capacity requirement far enough in the future to allocate each LSE's responsibility to develop additional capacity. But this ignores the existence of retail access and competitive LSEs. In states with retail access, loads may choose which LSE supplies their electricty. Since LSEs generally do not lock up their customers far in advance, LSEs do not know their shares of the capacity requirement that far in advance.[42]

An underlying misconception, running through much of the criticisms of RTO energy markets, is the assumption that prices are artificially higher in bid-based RTO markets, and that if we could just foreclose or limit use of the RTO markets, we could force suppliers to sell energy, ancillary services and capacity through contract arrangements for less than buyers/consumers pay now.

This central assumption is false; it ignores repeated findings by RTO market monitors that the total revenues generators receive from all energy and ancillary services markets is typically less than the generators' total fixed and variable costs, when calculated using cost-of-service methods. If that is true, then what critics are implicitly advocating is a set of rules that would discriminate among suppliers of capacity and allow buyers to force sellers to accept prices below market levels, while still expecting suppliers to build sufficient capacity to meet regional reserve requirements.

There is no theoretical basis to support these assumptions. Whether buyers and sellers rely on RTO-administered auctions or on self-supply or bilateral contracts, suppliers must receive total revenues that cover the fixed and variable costs of developing new resources. There is no magical, non-discriminatory set of rules that will allow the region to meet its planning reserve requirements without paying those costs.[43]

Finally, PJM's RPM construct does not add a capacity payment on top of the generator's revenue requirements. Instead, capacity payments under RPM reflect the difference between the margins that generators are expected to realize in energy and ancillary services markets and the total cost of developing and maintaining new capacity. Thus, if expected energy market profits went up, capacity payments under RPM would go down.

42 If forced to designate their loads before they are locked in, non-utility LSEs would have an incentive to underestimate their future loads and lean on the residual utility.

43 PJM's RPM construct has the effect of spreading out total capacity costs over time, rather than having those costs imposed in lumps as each set of "needed" new capacity is added to the system. This means that in any given year, buyers could pay more or less than they might under a fully regulated cost of service regime. But over time, the expected costs should be about the same.

This is an important relationship for those seeking to reform RTO capacity markets. Reducing the level of capacity payments required by controversial capacity market mechanisms can be accomplished by improving the rules by which RTOs price energy and operating reserves. Particularly during periods when the system is short of operating reserves, current RTO pricing rules fail to reflect the higher value of energy and operating reserves. The result is a gap in revenues that must be recovered through some other means-and that gap drives much of the need for capacity payment mechanisms.

Capacity markets and payment schemes are difficult to design and are probably not the ideal way to ensure sufficient revenues to support resource adequacy objectives. While they can fill the gap in revenues from incomplete energy and reserve markets, they may not provide the best incentives to encourage strong demand-side responses or generator availability in those rare periods when short-term capacity shortages arise. Improvements in scarcity pricing would close this gap and thereby reduce the need for capacity payments and the importance of capacity market constructs. Equally important, improved spot market pricing for energy and operating reserves would improve real-time price incentives for more responsive generation and demand-side investments and actions. The combined effect would be to lower total costs and improve reliability.

IV. Contract Scheduling, The Wrong Contract Path, Again

The contract-scheduling structure APPA originally proposed in *Consumers in Peril* and *Kelly/Caplan* would take us down the wrong path, again. At its core, the proponents' analysis assumes that it would be an easy matter to support non-discriminatory transmission open access that relies on a system of physical transmission rights. If this assumption were true, then it would be possible, even natural, to restructure the electricity system around physical rights and long-term bilateral contracts that would reduce the need for RTO market coordination and avoid the need to exercise great care in designing the details of the (small) balancing system and associated spot market.

This is an old, discredited idea. For example, in the early days restructuring the electricity market in the United Kingdom, more than twenty years ago, there was an extensive effort to develop a contract-scheduling scheme that was famously abandoned in favor of the spot market coordinated by the independent system operator.

The idea has a superficial appeal, and like a bad penny it keeps cropping up in various guises. Most prominently, in the mid-1990s, Enron championed essentially the same contract-scheduling model for electricity markets built around physical transmission rights, forced bilateral transactions, and suppressed spot markets. (We summarize California's experience with the Enron model in Appendix C.) But the model violates basic principles of economics and physics, and was eventually abandoned. The history of failed attempts makes clear the danger of repeating experiments that have been tried and rejected, often at substantial cost.

A. Reduced Grid Access and Trading

Just as Enron argued in the mid-1990s, more recent proponents of a contract-scheduling framework believe it is wrong to give parties the choice of relying on RTO-coordinated spot markets even when it is economic for them to do so. Therefore, market rules should somehow limit access to spot markets to force parties into bilateral contracts or self-supply arrangements.[44] For example, APPA argued in Consumers that "[p]rices for power sold under bilateral contracts (individual contracts between a buyer and a seller) have been substantially influenced by the high prices sellers can obtain in the RTOs' centralized markets."[45] In *Competitive Market Plan*, APPA's intent remains to reduce the use and influence of these spot markets.

The contract-scheduling framework would force parties to arrange and submit to the RTO balanced (supply matching demand) bilateral (or self-supply) schedules, months, weeks, days and hours ahead.[46] This would be counterproductive. Restricting the scheduling parties' access to the spot market would undercut the stated goal of promoting bilateral trading.

A contract-scheduling framework suffers from a fundamental flaw: it fails to recognize that scheduling bilateral contracts on a finite transmission grid must be facilitated by the dispatch coordination provided by the central system operator (the RTO). The central operator uses the spot market offers and bids to arrange its generation and load dispatch to accommodate the many parties' schedules so that

44 Although APPA has not explained how it would restrict access to the spot market, such restrictions would be necessary to implement the APPA model. As described in Appendix A, in the failed early model in California, with its separate Power Exchange and Independent System Operator, the goal was to limit the role of the spot market operating through the balancing function. To achieve this goal, the designers found it necessary to create explicit restrictions on the spot market to prevent economic dispatch with efficient balancing and to require balanced bilateral schedules. These restrictions contributed to the California crisis in 2000-2001, which led to the subsequent abandonment of the Enron-type model and demise of the separate Power Exchange.

45 *Consumers in Peril*, at vi.

46 *Kelly/Caplan* at 539: "LSEs could be required to submit anticipated loads at specified intervals (*e.g.*, month ahead, week ahead, day ahead, hour ahead), and the schedule of generation resources they have the right to call upon to serve those loads (including both generation and demand response resources)."

the total flows across each transmission element do not exceed safe operating limits. To ensure reliability, the operator must also use the offers and bids to balance the dispatch so that the total injections (supplies) match total withdrawals (demand plus losses) every moment, while respecting the limits imposed by the transmission system.

Without the essential coordination performed through the spot markets and associated dispatch, a bilateral contract and scheduling regime cannot function without limiting access to the grid and discriminating among the parties. Limiting access to the spot markets and associated dispatch would force restricted access to the grid, which would in turn limit and complicate economic trading, thus raising the costs of serving load.

The transmission grid must be able to accommodate the simultaneous flows associated with parties' schedules and ensure delivery, but effectively meeting this condition requires the RTO's central dispatch coordination. Together, the pattern of schedules and the operator's dispatch determine flows across limited transmission elements. In short, dispatch and feasible scheduling cannot be separated.

B. Unworkable Physical Transmission Rights

Under the contract-scheduling framework, the grid could not be scheduled in advance with assured delivery without first rationing grid access. Without rationing, parties could submit advance schedules, but some schedules would be infeasible (exceed grid limits) and have to be rejected in advance or curtailed in real time. To solve the problem it created, this framework would force the RTO to ration use of the grid, forcing parties to purchase a limited number of physical transmission reservations in advance and submit to possible physical curtailments after the fact.

There has been a great deal of experimentation and analysis devoted to this problem in the past.[47] As the experience in physical rights systems has shown, prior rationing and later curtailments are needed to "unschedule" the grid when, as often happens, scheduled flows exceed limits and cause congestion. Historically, physical rights rationing rules permit fewer accepted schedules and hence fewer trades, leaving the grid underutilized. These results would be the opposite of the stated goals of promoting forward bilateral contracts and scheduling. [48]

The contract-scheduling approach thus has the solution exactly backwards. Restricting access to the dispatch/spot market undermines contracting, while open access to an RTO's spot market facilitates contracting. Open access is thus not a design flaw; it is an essential feature benefiting all parties.

The spot market defines and prices the RTO's dispatch, and the dispatch provides the coordination needed to support bilateral trading, providing balancing for schedules and dispatch adjustments to avoid transmission congestion that would otherwise force schedule curtailments. Open access to the dispatch/spot market allows robust forward markets, which then help support investments in generation, transmission and demand response.

Furthermore, the existence of the RTO market provides the framework to create workable Financial Transmission Rights that substitute for the unworkable physical transmission rights. Importantly, *Kelly/Caplan* asserts that "[t]he Day 1.5 market design proposal presented in this article could potentially work with either a physical rights or financial rights transmission service regime."[49] This is a critical claim that is never explained; it glosses over the intrinsic requirement that financial transmission rights be integrated with an open spot market with locational prices.

As the RTO adjusts dispatch to manage congestion, it produces differences in locational prices.

47 Hogan, "Reforms of Reforms."
48 *Kelly/Caplan*, at 491.
49 *Kelly/Caplan* at 534, footnote 204.

Schedule imbalances are settled at these prices. Furthermore, parties with transmission schedules are charged the difference in the locational prices between each schedule's source and destination. Hence, transmission usage is equivalent to the identical physical transaction of selling at the source and buying at the destination. This fundamental equivalence means that the spot market outcome, transmission schedules, and economic dispatch are internally consistent. Therefore, there is no incentive for market participants to distort decisions because of different treatment of physically identical transactions. This critical consistency would not be available under any other system, and breaking the connections creates incentives to game the schedules or dispatch.

By design, FTRs are entitlements to payments (or debits) from the spot market, based on the differences in locational spot prices between each FTR's points of injection and withdrawal. Thus, FTRs are defined by and consistent with the spot market prices. Without the open spot market with locational prices, the financial transmission rights would no longer be consistent with actual opportunity costs of using the grid. This disconnect would create incentives for parties to game their schedules and the dispatch, and to submit schedules that make congestion worse.[50]

On this point, there is a real danger in offering the contract-scheduling framework while overlooking a fundamental contradiction. It is not possible to have it both ways, with restricted spot markets and consistent financial transmission rights. It is the open spot market with efficient pricing that creates the possibility to offer a consistent system of financial transmission rights in lieu of the unworkable physical rights.

Limiting access to the spot market would limit the ability to utilize FTRs and re-create the previously unsolved problem of defining a workable system of physical transmission rights. The restrictions are inherent in the earlier Enron contract-scheduling framework, which APPA and other RTO critics seek to recycle.[51]

In *Consumers in Peril*, APPA proposed to limit parties' ability to rely on the RTO spot markets to "no more than 5 percent of load." [52] With only a limited balancing market, LSEs would be forced to meet their loads using self-supplied generation and energy purchased through bilateral contracts; they would need additional arrangements to cover large imbalances if they needed to replace or supplement their contracted supplies. However, APPA's arbitrary 5 percent limit on RTO balancing would result in LSEs facing greater risks and higher costs in reliably serving their loads. And as experience shows, specifying the details of how to achieve this limited access would expose the problems that have arisen when such limitations have been tried.

Under the "Day 1.5" proposals, virtually all trading would still be restricted to bilateral contracts between suppliers and LSEs, just as proposed in *Consumers in Peril*. To be clear, bilateral trading *per se* is not a problem; it is used extensively in RTOs today by parties choosing that option; RTO dispatch fully accommodates the resulting schedules. Many of the details of RTO market design were created to facilitate the ability to use bilateral contracts in the face of the complex multilateral interactions across the transmission grid. But facilitating bilateral contracts is a quite different thing from prohibiting alternatives and compelling reliance on an unworkable system. The difference is that parties in today's RTOs also have another choice: trading through the auction-based RTO dispatch/spot markets when it is more economic to do so, an option APPA still seeks to limit or foreclose.

It makes sense that APPA has moved beyond the contract-scheduling framework. That framework falls short of ensuring open, non-discriminatory access to transmission and supporting a robust forward contracting market. As critics continue to reinvent electricity market design with all the mechanisms that must be in place both to ensure reliable operations and to allow their members and other parties

50 There is ample experience from California and elsewhere with parties gaming bilateral schedules and dispatch offers to exploit inconsistencies between the spot market and the opportunity costs of using the grid. See Appendix A.

51 *Consumers in Peril*, 27-28.

52 *Consumers in Peril*, 27.

open, non-discriminatory access to the transmission *grid*,[53] they will rediscover virtually every feature of the current RTO Day 2 Markets.

Any model that prohibits access to the spot market or depends on undermining economic dispatch should bear a strong burden of proof, and its proponents should not be allowed to ignore this central dilemma. Without the restrictions on the spot market, the distinction between physical and financial transmission rights disappears, and the Enron-like model for transmission scheduling and dispatch would quickly evolve into the existing RTO design. [54] The costly restrictions are an essential part of the RTO critics' preferred approach.

53 Federal statutes and FERC rules require that transmission owners/operators provide parties access to the transmission grid on terms that are "not unduly discriminatory." APPA claims to support these goals, though its proposals would make their full achievement unlikely.

54 PJM and most other RTOs operate two short-run auction-based exchanges: a day-ahead financial market, in which parties can buy and sell energy for the next day and lock in day-ahead transmission charges, and a real-time market that determines the RTO's actual real-time physical dispatch. Parties may choose to participate in the voluntary day-ahead market, but every party using the grid must settle its schedule imbalances and additional redispatch costs in the real-time market.

V. The APPA Reforms Could Frustrate Federal and State Policies

There is an inherent tension between the APPA market framework and the electricity policies being pursued in many RTO states. At its core, the APPA approach focuses on limiting or discouraging access to RTO spot markets, while forcing utilities/LSEs to rely almost exclusively on bilateral contracts or their own generation. However, many state electricity policies depend on open access to the RTO spot markets.

In recent years, many states have supported wholesale and retail competition, alternative/renewable energy development and enhanced demand-side response. Various RTO rules, including open access to spot markets, are expressly designed to accommodate these policies while also accommodating states that choose not to pursue one or more of them.

For example, PJM facilitates more efficient demand response by basing its spot prices on LMP and making them transparent (through settlements and publication on PJM's web site). Since the LMPs represent the marginal cost of serving load at each time and location, they provide the correct price signals for the value of consumer demand reductions at each time and place, indicating when and where demand-side efforts make economic sense. Utilities/LSEs facing these LMPs then have efficient incentives to implement demand-side efforts. In addition, several states now use the LMPs as the default price for at least those larger customers eligible for retail choice, encouraging the customers to implement their own demand reductions at times when prices are highest.

In the PJM region, several states have adopted policies to promote both wholesale and retail competition. Some states supported those policies by requiring or encouraging their regulated utilities to divest generation; others did not. The PJM region thus includes many utilities and non-utility LSEs that do not own generation to serve their loads. They purchase power from the wholesale markets, either through bilateral contracts or through purchases from the PJM spot energy and capacity markets. The ability to use the PJM markets provides an important option for these LSEs, allowing them to cover any part of their load that is not covered by bilateral contracts. The LSEs can choose that option in advance, or they can attempt to arrange and schedule sufficient contracts to meet their loads, while using the PJM spot markets to cover day-ahead or real-time imbalances associated with those schedules. The choice is left to the LSEs, but APPA would take away that choice.

PJM also accommodates dozens of non-utility third-party generators, including independent developers of renewable and alternative resources. These third-party generators can sell energy through PJM's spot markets and capacity in PJM's RPM capacity market, whether or not they have contracts with utilities or LSEs. If such a generator sells energy through a bilateral contract, it can use the PJM spot markets to cover any imbalances. Intermittent generation resources, like wind turbines, can also sell their power directly to the spot market and receive the spot price for the power they inject. This open access to the PJM spot market reduces entry barriers, allowing these generators to secure financing and compete more effectively with utility-owned generation.

The ability of LSEs and third-party generators to access PJM's energy and capacity markets is essential to their viability and hence the success of state policies favoring their development. Indeed, it is difficult to imagine how third-party generators, divested utilities and independent LSEs could function successfully without unrestricted access to the PJM markets. For example, how could the capacity structure work with load switching (in retail choice states) without detailed rules requiring capacity to follow loads? And how could parties contract long term with load switching?

Utilities in states that do not have these same policies also benefit from access to RTO markets, but they could conceivably tolerate more restrictive access to those markets, as shown by the approach taken in the Southwest Power Pool (SPP). In SPP's market region, states have generally retained vertically integrated utilities, avoided divesture and not implemented retail choice; there are no non-utility LSEs competing for retail load and fewer independently owned generators. The utility members of SPP own most of the generation they need to meet their own loads and purchase the remainder through bilateral contracts. Development of renewable resources or other alternative generation technologies occurs primarily, if not exclusively, under contracts with vertically integrated utilities.

Given this structure, SPP employs some features common to other RTOs but retains other features left over from its pre-RTO days. For example, SPP requires each utility member either to arrange schedules in advance to serve its own loads or to offer sufficient generation to SPP's central dispatch to meet those loads. The utilities must also reserve physical transmission rights to support moving this generation to load, an approach that tends to reduce grid access and leave the grid underutilized. Such "balanced" schedules and physical rights reservations are not required in other RTOs. On the other hand, once these schedules are submitted, SPP arranges a bid-based security-constrained economic dispatch to balance the system and adjust the dispatch to avoid congestion, just as PJM does. Moreover, SPP then prices the dispatch using "locational imbalance pricing" (LIP) which is essentially the same as LMP.

SPP is likely to evolve by developing the remaining functions now provided by PJM and other RTOs. For now, however, SPP can function with this still-developing hybrid because it does not have to provide non-discriminatory access to non-utility LSEs nor support significant third-party generation that is not contracted to utilities.

VI. The APPA Proposals Would Overburden Market Monitors But Not Reduce Prices

APPA seeks something closer to cost-of-service regulation for all generators, including those not owned by utilities. Generators would be required to offer their power to the RTO for dispatch, but every dispatch offer would be fixed by the RTO market monitors at each generator's individual short-run marginal cost (SRMC), but ignoring opportunity costs (recall the discussion in Chapter I of how this would suppress spot prices).

The task APPA has in mind for the market monitors is more detailed and intensive than anything currently performed by state utility regulators and public utility boards. PJM's region has literally hundreds of generators, each with a different cost structure. For each supplier, fuel prices can vary daily, and countless other factors shape each generator's marginal costs. APPA does not explain how the RTO market monitors could perform this level of cost-of-service regulation at the required level of detail.

In addition to assuming this burden, market monitors would be required to examine all contracts between generators and LSEs.[55] This task would not be easy, since APPA states that each contract would be tailored to match not only the needs of each LSE but the operating costs and investment requirements of each generator.[56] Since generators could not expect to recover their fixed investment costs from the suppressed spot market prices, and APPA would eliminate capacity markets and payments, generators would be need to recover those investment costs in contracts overseen and approved by the market monitors.

The proposed monitoring framework is a substantial departure from how RTOs operate today. In today's RTOs, price incentives encourage generators to bid their marginal costs, thus minimizing the need to monitor every generator's bids. Market monitors can then selectively focus on specific generators bidding into the RTO spot markets.

Today's market monitors evaluate market concentration in specific areas (load pockets) in which transmission limits create conditions vulnerable to market power. The monitors apply market power mitigation measures to specific plants to prevent economic or physical withholding. In such situations, the market rules require that spot prices be based on offers/ bids mitigated in advance by the market monitors to reflect marginal costs or prices acceptable to the market monitor. The results, confirmed by RTO *State of the Market Reports*, is that generation offers generally reflect marginal operating costs, while overall spot prices do not exceed competitive levels.[57] There is no need for this extensive, and probably unworkable, system of cost-of-service regulation APPA describes. The proposed reforms would work against the principles of efficient operation.

Spot prices then have an effect on forward contract prices. Since both buyers and sellers can always buy/sell power from the spot market at competitive prices, forward contract prices tend to reflect expected spot prices. Accounting for differences in risks, contract prices are not likely to be significantly higher (or lower) than expected average spot prices over the same period. Market monitoring and mitigation in the spot markets thus helps to ensure contract prices are also competitive. Under the APPA framework, spot prices would not include opportunity costs and contracts would not reflect expected spot prices. Hence every contract would differ. The APPA framework would overwhelm the workable structure market monitors have developed.

It would also likely create supply shortages. The RTO's focused mitigation efforts in spot markets help

55 *Competitive Market Plan* at 19-22.
56 *Competitive Market Plan* at 22.
57 PJM's *2007 State of the Market Report*, available at www.pjm.com

keep contract prices competitive, but by suppressing spot market prices, APPA's proposals would tend to suppress contract prices as well. Suppressed spot prices and suppressed contract prices translate to shortages, unless there are capacity payments to provide the "missing money" needed for investment. But APPA would eliminate capacity market payments.

Importantly, *Kelly/Caplan* recognizes that if spot prices were based on marginal operating costs, as PJM's Market Monitor finds they generally are,[58] then PJM's spot prices would be attractive to buyers. But that happy result is seen as a problem that requires rules to force buyers not to use the spot markets:

> Without market features requiring purchasing LSEs to maintain a portfolio of longer-term generation resources to serve their loads, the temptation for them to simply rely on the short-run marginal cost-based short-term optimization markets for a substantial portion of their power supplies could be quite high. In such an environment, the generators' claims that they were suffering "missing money" (*i.e.*, that they were not recovering their fixed costs) might well be justified. To prevent this result, we propose to impose on LSEs a "resource adequacy" requirement to obtain sufficient longer-term generation resources to serve their anticipated loads, thus preventing them from "leaning" on a short-term optimization market intended primarily as a balancing market.[59]

This is an important insight. The reason the "missing money" arises is, as *Kelly/Caplan* suggests, because prices in PJM's current energy and reserve markets do not cover the full fixed costs of building and maintaining the capacity needed to meet reserve requirements. By definition, that means that spot market prices are not "too high," because they don't fully cover the cost of sustaining existing or developing new generation. If capacity payments are not to be used to cover this missing money, then logically spot market prices must be higher if total market revenues are to cover the cost of developing generation.

Having encountered the underlying dilemma, it is important to address its remedy. Today's spot prices are insufficient when the region experiences shortages. Under current rules, spot prices are not allowed to reflect scarcity when the system is short of operating reserves. That means the underlying "missing money" problem could be mitigated by reforming energy and operating reserve pricing to include shortage-cost pricing, thus reducing the "missing money" problem that creates the need for capacity payments.

Without that preferred outcome, the RTO needs a capacity payment regime, such as RPM, to collect the "missing money" and pay it to generators. The *Kelly/Caplan* statement implicitly confirms that some type of capacity payment system is justified. But instead of paying the "missing money" through PJM's RPM, critics would require LSEs in the region to pay the missing money through higher prices in long-run forward contracts. That approach would then need some type of enforcement mechanism to force LSEs to contract for the right amount of capacity.

We have been here before. The original eastern power pools required each utility to build or contract with sufficient capacity to meet its share of reserve requirements, just as APPA proposes. When utilities fell short of their requirements, they could not be allowed to lean on others, so they were penalized. But to be effective and provide the correct incentives to acquire the right amount of capacity, the penalties must be related to the market value of capacity, and capacity auctions administered by the RTO (such as RPM) help define that value.

APPA apparently believes its forced contracting regime would provide contract prices sufficient to support the level of investment needed to meet the regional reserve margin targets. But having rejected capacity payments, its proposal includes no mechanism by which the necessary revenues would occur through contracts. Unless something intervened to force higher contract prices, suppressed spot and contract prices would produce market revenues insufficient to cover investors' fixed costs. That

58 Ibid.
59 *Kelly/Caplan* at 539 (emphasis added, footnote omitted).

means the region would fail to meet its resource adequacy (reserve margin) targets.

But suppose there were some magic way to compel LSEs to sign contracts with enough generators at prices high enough to support the required reserve margins. By definition, that means the contract prices would provide the "missing money" so that the total market revenues received by generators would be enough to cover the investment costs of the target level of reserves. But of course, that is essentially what the capacity markets do today; they provide capacity payments to generators to replace the missing money. So replacing capacity payments with sufficiently higher contract prices would not reduce total electricity prices.

Regardless of any concerns APPA may have about the details of each RTO's capacity market structure, APPA's basic assumption is *simply wrong. It cannot reduce total electricity prices by dismantling the* RTOs' capacity payment systems (see Appendix F) while simultaneously suppressing spot and contract prices. The revenues to meet the investment requirements must come from somewhere.

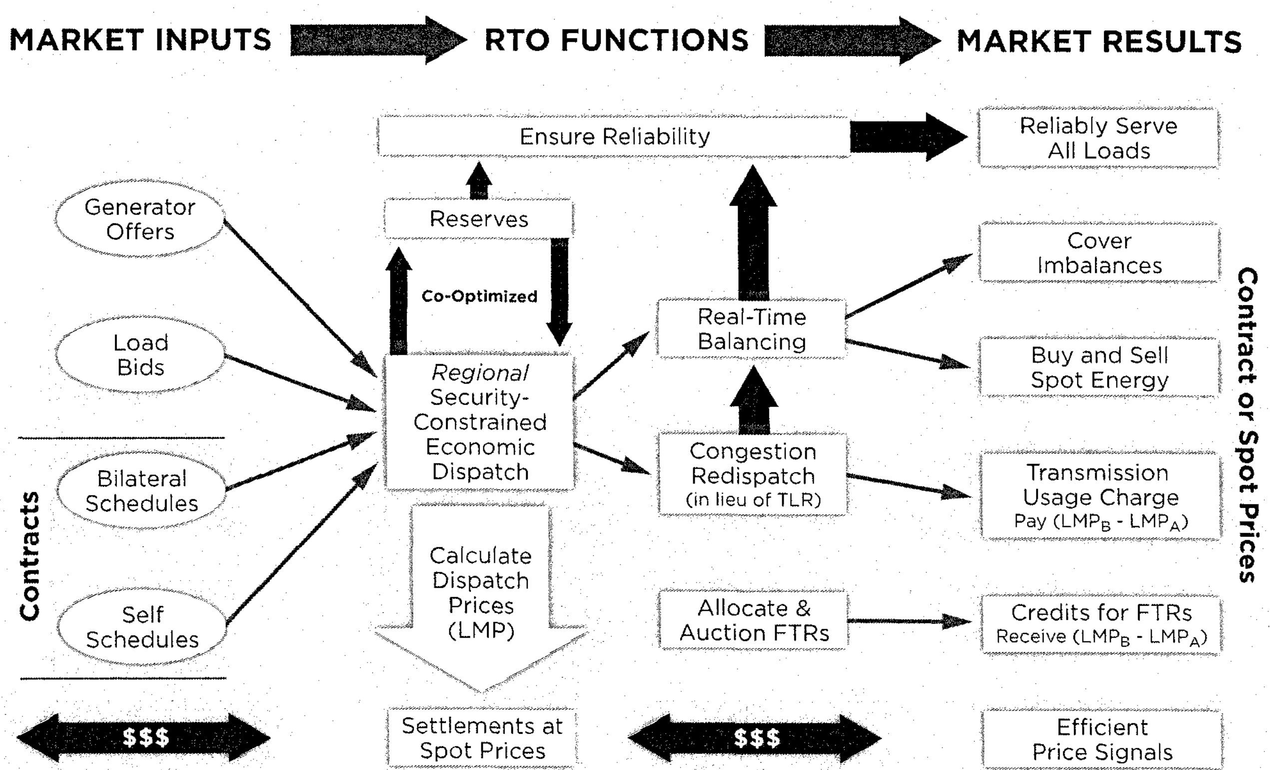
To meet the region's reserve margin targets, the total revenues needed to support that level of supply investment must be provided, one way or another. Much of it can come from spot prices and contract prices linked to spot prices, if those prices are not artificially suppressed. Moreover, if spot markets were improved to include scarcity pricing when the RTO is short of operating reserves, then spot markets and contract prices would recover even more of the needed revenue requirement, while the need for capacity payments would diminish. But whatever is left must be recovered through some mechanism, presumably capacity payments. There is no magic formula that allows APPA to escape this equation.

VII. The RTO Approach Is A Proven, Superior Model

PJM and other RTOs operate on a reliability foundation common throughout the industry. To maintain reliability at each moment, every system operator must keep generation (supply) exactly in balance with consumption (demand) plus transmission losses. To avoid system failures and outages, it must also ensure the energy flows across any transmission line or element do not exceed the safe operating limits for that component.

Every modern system operator accomplishes these tasks through a process called "security-constrained economic dispatch," by which it determines which generators will operate and how much energy (or voltage support) each unit will produce at each location on the grid. The dispatch is "economic" in the sense that the system operator chooses the lowest-cost (or lowest bid cost) mix of plants available to dispatch to balance the system and manage flows to avoid congestion. All RTOs follow this standard industry approach. The modern RTO framework is illustrated in the following figure.

Figure 1: RTO Maintains Reliability Using Security-Constrained Economic Dispatch. The Spot Market Defines/Prices Dispatch



Voluntary offers and bids to determine the RTO's dispatch, and settlements for energy bought and sold through the dispatch, create a "spot market," which is the financial side of the essential physical dispatch. After each dispatch interval, the RTO determines the locational spot prices, based on the actual dispatch.

While many generators make their plants available for economic dispatch (it makes economic sense for them to do so), most energy is eventually priced to retail consumers through contracts or cost-of-service approaches. As Figure 1 shows, utilities may self-schedule their own plants to serve their own loads, or schedule bilateral transactions to move power from sellers/suppliers to buyers/loads. The RTO accepts and accommodates all of these schedules by arranging its security-constrained economic dispatch to accommodate any fixed schedules submitted by the parties.

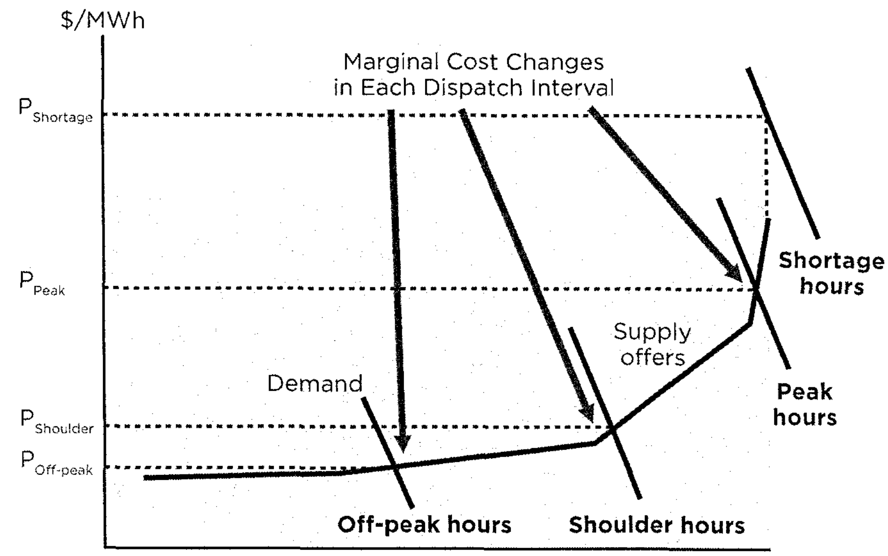
If these fixed schedules would overload any transmission line or element, the RTO routinely adjusts the dispatch (a step sometimes called "redispatch") to redirect flows and relieve the congestion. The RTO then charges each affected schedule the marginal costs of any redispatch needed to accommodate that schedule, so that no party is "leaning on" or subsidizing any other party.

If parties deviate from their set schedules, the RTO covers their imbalances by simple adjustments to the dispatch, ensuring that all load is reliably served at all times.[60] The RTO then settles the deviations at the LMP spot price, which reflects the dispatch marginal cost for covering each imbalance at the time and location where it occurred.

Thus, the principle used by all RTOs is that every grid user gets access, each user pays for whatever costs it imposes on the dispatch and is compensated for whatever benefit it provides. There are no cross subsidies, and no party "leans" on any other party. Since every party has access to the grid via open access to the dispatch (and redispatch if needed to relieve congestion), these principles mean that RTOs fully satisfy the federal mandate to provide open access transmission service to all parties without discrimination.

The LMP spot market prices reflect the marginal cost of operating the dispatch and thus the value of power at each time and location. They are used to pay parties that sell power through the dispatch and to charge parties for the power they purchase through the dispatch in each hour. The LMP spot prices routinely change each hour (or shorter dispatch interval) as a different mix of plants with different marginal costs is dispatched in each interval to match ever-changing demand.[61] See Figure 2. If there is congestion, LMP will also vary at different locations, reflecting the change in marginal costs as different power plants are instructed to raise or lower their outputs at each location so as to redirect flows and avoid congestion.[62]
The principal gap in implementing the LMP design is during shortage hours. Although the shortage price defined by

Figure 2: Marginal Costs Define RTO Spot Market Clearing Prices



Clearing Price rules encourage generators to bid marginal (or opportunity) cost and to follow dispatch instructions

60 For example, suppose a party scheduled a bilateral transaction in which it planned to inject 100 MW at location A and withdraw 100 MW at location B. In real time, however, the party only injected 95 MW, instead of the scheduled 100. In that case, the RTO would simply dispatch 5 more megawatts from other generators to cover the imbalance, thus reliably serving all load. The dispatch is thus a "balancing market." The party with the imbalance would be charged for the 5 MW supplied by the dispatch times the LMP at location A. Any imbalance, on the supply or demand side, would be automatically covered by the dispatch and the parties charged (or paid) accordingly.

61 RTOs readjust the dispatch every five minutes to follow rapidly changing demand. Thus, marginal costs of serving loads, and hence spot prices, are also changing every five minutes. In some RTOs (New York), the five-minute spot prices are used directly for settlements; in PJM, five-minute prices are aggregated into hourly prices for settlements.

62 Marginal costs will also vary due to losses, but we ignore this for the purposes of this discussion.

the demand curve is evident in Figure 2, it has been harder to include this logic in RTO market design and software. The issue of scarcity pricing is one area where RTO reform is under consideration.[63] However, the effect will be to make spot prices higher, not lower, and this well-founded reform is not addressed in the APPA critique.

Transmission scheduling problems are at the center of the challenges in providing open access and non-discrimination. But critics are often silent on how they would address these well-known problems; they assume that the contract-scheduling model with physical rights could be made to work and meet non-discrimination requirements, despite the experience.

The modern RTO design solves this scheduling/delivery problem. As Figure 1 illustrates, the RTO model gives parties expanded access to the grid by allowing them access, though the spot markets, to the system operators' security-constrained, economic dispatch (including "redispatch" service to avoid congestion). The dispatch accommodates the parties' schedules without physical rationing, requirements for obtaining physical rights in advance, or risking curtailments later. By going down the wrong path, again, restricted access to spot markets and the resulting need for contract scheduling with physical rights would discard these hard-won advantages.

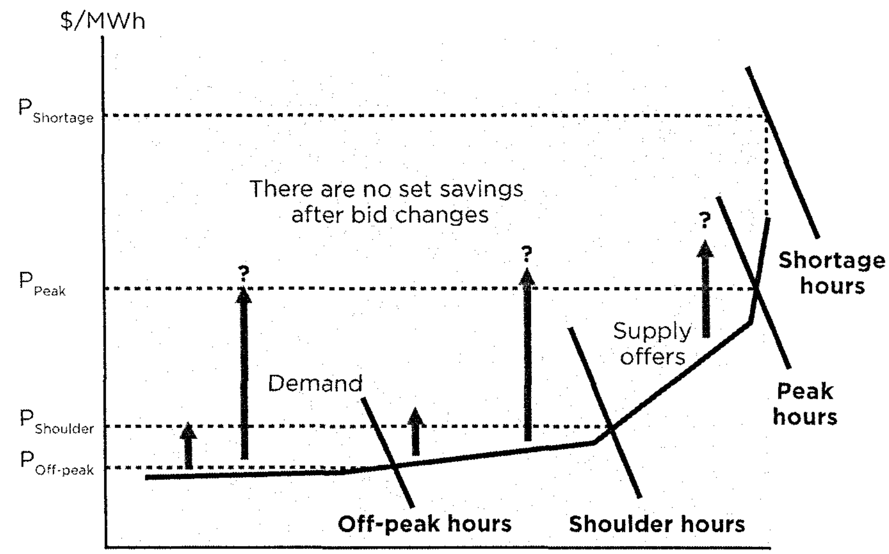
In *Consumers in Peril*, APPA proposed to replace the "clearing price" approach for the spot market, but it did not explain how any other method would work. In *Competitive Market Plan*, APPA would retain clearing prices. RTO dispatch/balancing markets use LMP to price the energy bought and sold through the dispatch. LMP is a clearing price approach, in which the price at each location represents the marginal costs of serving load during each dispatch interval. This means that lower-bid-cost units in the dispatch are paid a clearing price set by the marginal units in the dispatch.

This is a straightforward application of economic marginal cost pricing. However, critics argue this approach overpays infra-marginal units. This assumes that such units would willingly and consistently sell their power at the lower prices they bid in a clearing price regime. There is no economic or logical basis for this assertion.

As various studies have explained,[64] if generators are faced with a rule that says they will be paid the prices they bid, they will change their bid behavior, raising their bids to their expectation of what the market-clearing price would be, as illustrated in Figure 3.

In the end, the "pay-as-bid" approach would be likely to raise costs, because bidders may overestimate the expected clearing prices, causing less efficient generators to be dispatched in their stead. Moreover, if suppliers could somehow be forced to sell their power for less than the market-clearing price—that is, for less

Figure 3: Pay-as-Bid Rules Result in Generators Changing Their Bids



Pay-as-bid rules encourage bidders to raise their bids to expected market-clearing levels.

63 FERC, Order 719, October 17, 2008; PJM *2008 State of the Market Report*, Recommendations, pp.6-7.

64 *E.g.*, see Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, Richard D. Tabors, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" January 23, 2001.

than what it is worth at that moment and location—the long-run effect would be to discourage and limit investments needed to sustain the suppliers over time or replace them when they retire.[65]

The RTOs' operation of these markets is the essential ingredient that allows for competition and provides open access to the transmission grid without discrimination. Through these markets, the RTO provides coordination for competition, allowing participants to arrange bilateral contractual commitments without producing energy schedules inconsistent with safe and reliable operation of the grid. The dispatch/spot market captures the interactions among many market participants and then prices the needed dispatch services accordingly, using locational prices.

The RTO approach is not merely a workable, fair and efficient solution; it is a vast improvement over the restrictive physical rights regime that the RTO critics would force on RTO regions. The standard RTO design the critics would dismantle was recently characterized by the International Energy Agency in its review of market experiences across its member countries:

> "[L]ocational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design — the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."[66]

Any retreat to a failed contract-scheduling model would only raise transaction costs, restrict grid access and reduce interregional trading, while leaving the regional grids underutilized compared to today.

Electricity markets organized under RTOs are still evolving. The existing models are not perfect. But the remaining problems are in the area of scarcity pricing, transmission expansion, demand-side participation, and so on. The needed refinements call for better, not restricted, spot markets.

In short, an RTO model that uses bid-based, security-constrained economic dispatch with locational prices provides the foundation for open access and non-discrimination. It provides the framework for FTRs that solve the otherwise unsolved problem of how to make physical transmission rights compatible with open access, non-discrimination and efficient use of the grid.

Furthermore, this is the only model that meets these objectives. This is fundamental. Any suggestion to deviate from this model should bear a strong burden of proof. The critics' analysis does not fully acknowledge this critical problem, nor does it provide an analysis that meets the burden of proof in the face of overwhelming evidence against restricting access to the spot market and leaning on the contract-scheduling model.

65 The reason is that the difference between the clearing price and a marginal cost bid constitutes a contribution to the generator's fixed/capital costs. A properly structured clearing cost mechanism will thus cover both marginal operating costs and fixed costs. If generators are forced to forego this contribution, they will not recover their fixed costs, so future investments will be lower.

66 International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 116. Also see, Paul Joskow, "Challenges for Creating a Comprehensive National Electricity Policy." Speech given to the National Press Club, September 26, 2008, (http://www.hks.harvard.edu/hepg/Papers/Joskow_Natl_Energy_Policy.pdf). Joskow is a Professor at MIT, President of the Sloan Foundation and a member of the Exelon Board of Directors. He notes that the RTO model works well and is evolving in helpful directions; he recommends it be expanded and made mandatory across the country.

VIII. Conclusion

The recommendations of APPA and other critics of RTOs have undergone substantial evolution since *Consumers in Peril*. In one sense, this evolution might be viewed as progress as APPA confronts the realities of electricity systems that others have learned and embodied in the current RTO market design. However, a continuing missing chapter in the APPA analysis is any forthright description of the special characteristics of electricity systems that underpin the current RTO market structure. The several elements of bid-based auctions, economic dispatch, security constraints, locational prices, unit commitment, long-term contracts and capacity markets all work together to solve the complicated coordination problems that come hand-in-hand with an integrated transmission grid. The RTO market design elements are there for a good reason, and the lessons about missing pieces were learned at great cost.

Despite the repeated experience of failure with attempts to constrain spot markets, such proposals and the associated return to contract scheduling with physical rights would recycle the mistakes and perform radical surgery on the healthy vital organs of the working RTO markets. These recycled restructuring proposals misunderstand both the basic requirements of reliable grid operations and the prerequisites of efficient trading under a statutory requirement for open access and non-discrimination. Equally important, implementing restricted spot market access and the contract-scheduling framework would cost consumers billions of dollars. The APPA continues to sidestep the issues or give new labels to old ideas that obscure the message and ignore the lessons of the past. The APPA analysis is internally inconsistent, and its proposals disconnected from the real requirements of operating electricity systems. The APPA proposals point down the wrong path, again.

Appendix A: What Have We Learned About RTO Costs and Benefits?

The APPA-led analysis includes a number of arguments that expose critical misconceptions about how RTOs work and are working. Typically the misconceptions are implicit assumptions rather than explicit claims, but the implications of the errors are significant. The performance of RTOs is better than stated, quantitative and qualitative evidence of benefits are ignored, and critical market design connections are neglected.

Misapplying Cost and Benefit Studies

Evaluating the costs and benefits of RTOs is a challenging task. There are too many moving parts to allow for a simple comparison that might arise with a controlled laboratory experiment.[67] Some of the moving parts include the timing of various reforms within RTOs, the partly separable effects of state retail open access rulings, divestiture decisions for generation assets, transition plans for state rate restructurings, and so on. Most importantly, evaluating the costs and benefits of a component of RTO activities requires care in defining the question and developing the appropriate counterfactual for comparison.

The supporting analyses assembled by APPA do not address these details. Furthermore, in summarizing the attempts to address costs and benefits, APPA does not even consider all the costs or all the benefits, focusing on consumer impacts and finding only an absence of evidence of significant net benefits rather than contrary evidence:

> "Much time, energy and expense has been expended by all sides producing 'dueling studies' regarding the costs and benefits of RTO-run centralized markets. In our view, informed by both the literature and the actual experience of the APPA members in RTO regions, it is difficult to conclude that consumers have benefited from the implementation of these markets." [68]

The critics present a view that RTOs are not performing as intended:

> "Restructured wholesale markets are producing both higher prices and higher profits than one would expect in a competitive market. Resulting retail prices exceed those prevailing in regions that have not restructured, but that instead retained traditional retail cost-of-service regulation and eschewed the formation of RTOs. Long-term adequacy of generation resources is also a substantial concern in RTO regions."[69]

At the same time, the argument is that there are benefits from some aspects of RTOs (that apparently exceed the associated costs). For example:

> "We hasten to add that RTOs provide real benefits to consumers. RTOs provide independent and non-discriminatory transmission service under open access transmission tariffs (OATTs), charging regional transmission rates instead of individual system-by-system pancaked transmission rates. They maintain reliable transmission service through their wide-area-[view] of moment-to-moment system operations. They lead regional collaborative transmission planning processes. Such RTO functions undoubtedly benefit consumers. Yet the FERC's policies have increasingly lost sight of these core transmission-oriented RTO functions, as implemen-

67 John Kwoka, *"Restructuring The U.S. Electric Power Sector: A Review Of Recent Studies,"* APPA, 2006, (available at http://appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf)

68 Susan Kelly and Elise Caplan, *Time for a Day 1.5 Market: A Proposal to Reform RTO-Centralized Wholesale Electricity Markets*, 29 *Energy Law Journal* 491, at 514, (2008).

69 *Kelly/Caplan* at 494.

tation of centralized markets for energy, ancillary services, and generation capacity have taken center stage. It is the RTO-run centralized wholesale markets and their performance that are the primary focus of this article."[70]

Therefore, it is only part of the RTO design that is the subject of criticism for producing more costs than benefits. This formulation of the critique would be difficult to establish based on the available evidence, and the most relevant evidence does not support the conclusion that "centralized wholesale markets" create costs greater than their benefits. To the contrary, the weight of the evidence points to substantial net benefits from RTOs under a regime of open access and non-discrimination.[71]

A recent Government Accountability Office (GAO) report concluded that "FERC officials believe RTOs have resulted in benefits; however, FERC has not conducted an empirical analysis of RTO performance or developed a comprehensive set of publicly available, standardized measures to evaluate such performance."[72] The GAO did not identify what measures to employ, but surely the right questions would include at least the operational record, risk allocations, and investment decisions. The GAO subject was the combined effect of RTOs with restructured electricity markets. The GAO did not address the narrower APPA question about the independent effect of organized wholesale markets.

Apparently the critics agree with FERC that the evidence supports the view that RTOs provide real benefits. The FERC perspective includes the effects of organized wholesale markets in this benefit calculation, but APPA argues that the independent benefits of organized markets have not been worth the costs. Yet the available empirical evidence is inconsistent with this conclusion.

The critics' focus on retail price impacts of RTOs would require an experiment or methodology to isolate the effects of wholesale markets in RTOs from the many other activities that determine retail rates. Most of the comparisons cited in the APPA analyses suffer from the inability to isolate the independent effect of the RTOs from the separate impacts of state regulation, generation configuration and other confounding factors.

Notably, the best attempt to answer the question about the retail price impact of RTOs approaches the problem by limiting the analysis of retail rates to a comparison of municipal utilities (not subject to state regulation), for regions with similar fuel dependencies, and for regions included or excluded from an RTO. That study found a statistically significant residential rate savings of $430 million to $1.3 billion per year in PJM and the New York Independent System Operator (NYISO) from membership in an RTO.[73] The criticism of the result is principally about the small number of paired comparisons between similar RTO and non-RTO regions.[74] The small number of comparables is an inherent fact that limits the possible empirical analysis, but it does not change the conclusion.

RTO Market Coordination Reduces Curtailments of Contract Schedules

A focus on the criterion of retail rate impacts addresses part of the story, but it ignores other benefits that were intended to flow from the creation of RTOs. For example, part of the purpose of RTO design was to facilitate trading and reduce the need for administrative Transmission Loading Relief (TLR)

70 *Kelly/Caplan* at 494 (footnotes omitted).

71 Frank Huntowski, Neil Fisher, Aaron Patterson, *"Embrace Electric Competition or It's Déjà Vu All Over Again,"* The Northbridge Group, October 2008, (www.nbgroup.com).

72 Government Accountability Office (GAO), "Electricity Restructuring – FERC Could Take Additional Steps To Analyze Regional Transmission Organizations' Benefits And Performance," GAO Report 08-987, at i.

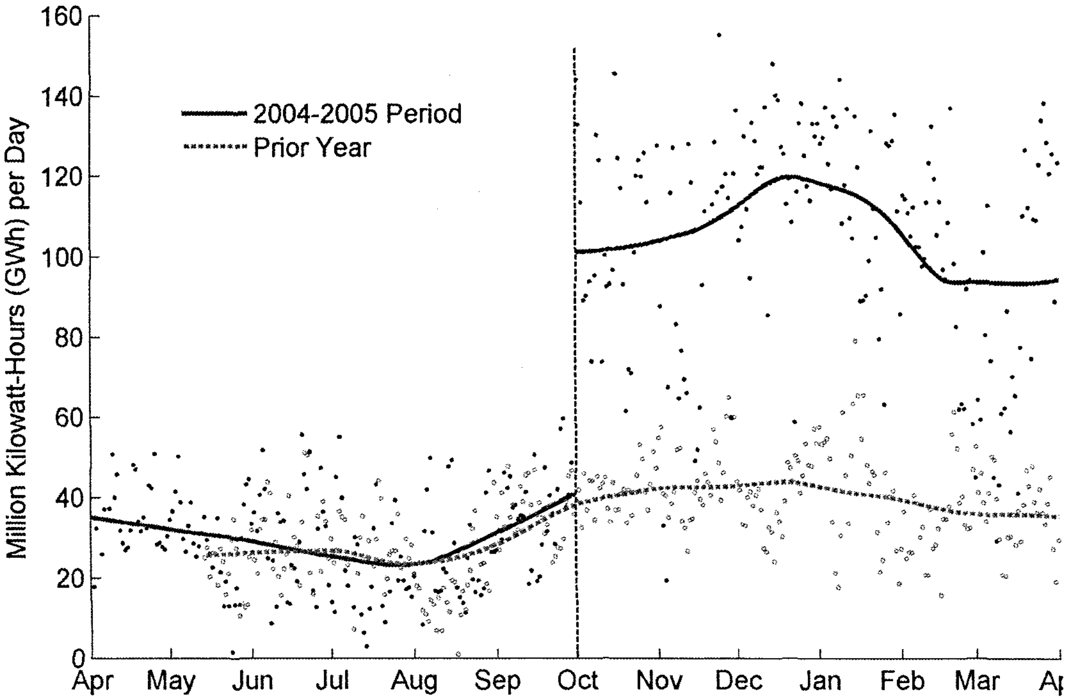
73 Scott Harvey, Bruce McConihe, and Susan Pope, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," LECG, November 20, 2006 (revised June 18, 2007) and available at http://www.lecg.com/files/upload/AnalysisImpactCoordinatedElectricityMkts.pdf.

74 John Kwoka, "Restructuring The U.S. Electric Power Sector: A Review of the LECG Study," Northeastern University, 2007. (http://www.appanet.org/files/PDFs/KwokaLECGReview.pdf.)

orders that curtail scheduled transactions to relieve transmission congestion.[75] In the case of PJM, there was an interesting experiment in October 2004 when utilities in the Midwest, including American Electric Power (AEP), converted from relying exclusively on a *pro forma* open access regime based on contract scheduling with physical transmission rights to membership in PJM with its centralized wholesale spot market using LMP and financial transmission rights. This was a relatively clean experiment that allows a before-and-after comparison of regional trading without much need for other complicated control variables.

The result, as shown in the following graph, was dramatic and abrupt. Immediately following the expansion, the monthly average of day-ahead exports from the Midwest to PJM tripled and stayed at the new higher level.[76]

Figure A-1: Quantities Traded: Day-ahead net exports, Midwest → East



A similar result occurred after completion of the expansion of PJM's footprint in 2005. If all other things had been equal, PJM's expanded responsibility for managing additional congested transmission lines should have required more TLRs for PJM. But to the contrary, and complementing the trading statistics, PJM TLRs started to decline in 2005 and average annual PJM TLRs at level 3 or above for 2006-2008 dropped to 27% of those in 2004, despite a general overall increase in reported TLRs.[77]

The PJM experience is important because it was a clean experiment and the trading results were unambiguous. However, the PJM expansion data combine the effect of moving from a bilateral trading arrangement to an RTO and the effect of participating in a centralized wholesale market, showing an

75 Transmission Line-Loading Relief (TLR) involves a set of NERC rules under which a reliability coordinator requires certain parties to curtail their transaction schedules until the excess flows on congested transmission lines fall within safe operating limits. In RTOs, dispatchers adjust the dispatch (redispatch), which changes the flows across selected lines and thus reduces the need for TLR curtailments. In non-RTO regions without open access to redispatch service, TLR curtailments become necessary and more widespread.

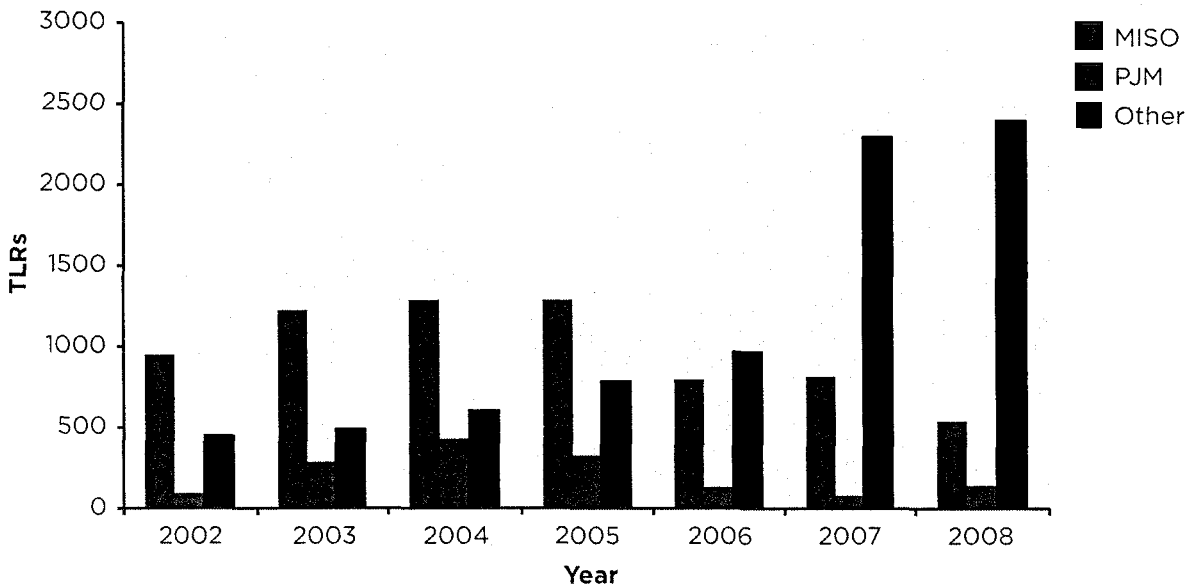
76 Erin T. Mansur and Matthew W. White, "Market Organization and Efficiency in Electricity Markets," October 2008, Figure 2, discussion draft (available at http://bpp.wharton.upenn.edu/mawhite/).

77 NERC, December 22, 2008, http://www.nerc.com/docs/oc/scs/logs/trends.htm.

increase in trading benefits. But the PJM expansion case does not isolate the effect of the organized market separate from the effect of an RTO as required under the approach advocated by APPA.

An examination of the TLR experience after the startup in the Midwest Independent System Operator (MISO) market in 2005 provides another experiment that comes closer to isolating the independent effect of the wholesale market. In February 2002, the MISO inaugurated operation as an RTO with an open access transmission tariff based on contract scheduling, but MISO did not launch the RTO-wide organized centralized wholesale market with LMP and FTRs until April 2005. The MISO showed an increasing frequency of TLRs while operating as an RTO without an organized market. But the increase reversed and was followed by a sharp decline in TLRs when the organized market was put in place. Comparing average 2006-2008 TLRs for the MISO shows a similar experience as in PJM, with a reduction to 56% of the 2004 curtailments.[78] TLRs in regions without RTO Day-2 markets have been increasing.

Figure A-2: NERC TLR Orders



The benefit from reduced reliance on TLRs and associated lower costs from RTO coordinated markets is clear. The short-run system cost savings might not appear immediately in retail rates, but enhanced trading through reduced curtailments could raise profits in the short-run and reduce the cost of entry in the long run.

Hence, the quantitative experimental evidence employed must be used with care to address the proper question. As the GAO concluded, a full evaluation of the impacts of RTOs and their associated wholesale markets would go beyond the limited empirical evidence available today. However, the evidence is incomplete, not absent.

In addition to the quantitative experimental test, there are two other approaches that suggest themselves for evaluating the costs and the benefits of RTOs and organized wholesale markets. One method would be to conduct counterfactual simulations to estimate the costs and the benefits of organized wholesale markets. This is a common practice. For example, this was the approach used in Texas in 2008 to evaluate once again the costs and benefits of moving to the full locational marginal pricing (LMP) model for the wholesale spot market; the study found that benefits were substantially greater

78 NERC, December 22, 2008, http://www.nerc.com/docs/oc/scs/logs/trends.htm. Most of the increase in "other" is in SPP, which is an RTO but does not have a Day 2 market.

than costs.[79] A further example of such a simulation for PJM is provided below and in Appendix E, and this too reinforces the view that there are substantial benefits from the operation of the RTO-wide co-ordinated spot markets.

Missing the Forest for the Trees

The experimental evidence usually considered in the cost-benefit analyses focuses on the quantitative trees but often ignores an important view of the qualitative forest. In many ways, this forest is the more substantial part of the overall cost-benefit picture. The view of the forest includes the qualitative experimental evidence in the experience with RTO designs that attempted to provide open access and non-discrimination without the centralized market of the type now operated by RTOs. This experience speaks directly to the RTO critiques and the approaches APPA has recommended.

As discussed further below, there have been many attempts to develop RTO structures without the organized, centralized wholesale spot market and the associated LMP design. Given the principles of transmission open access and non-discrimination, these alternative RTO models confronted a fundamental dilemma. In short, there is no RTO design that has been shown to work and provide consistent incentives under these principles other than the basic LMP model. Every attempt to build an RTO model without the LMP framework has failed, visibly and dramatically, and either led to comprehensive reform to embrace the LMP model or compromised on the basic principles of open access and non-discrimination.[80] This dramatic evidence is "hidden in plain sight."

There are many ways to fail, but a common thread in the failed models included contract-scheduling restrictions on the spot market, inconsistent pricing models, and reliance on bilateral transactions without the support of a well-designed spot market. For example, in 1997 FERC ordered PJM to follow the recommendations of an Enron-led coalition to implement a simplified single-zone balancing model for its "small" balancing transactions, and rely primarily on bilateral schedules. This early PJM system imploded on the first hot day in 1997, and threatened to put the lights out until PJM suspended the market. As a result, PJM abandoned the failed market design and moved quickly to an LMP-based open spot market with Financial Transmission Rights (FTRs) in 1998.[81]

New England adopted its own version of a "simplified" spot market without the coordinated wholesale market based on the LMP model. Because of differences in detail from PJM, the failure mode appeared in perverse investment signals that by 1998 had been recognized as leading to the wrong new generation location decisions. The initial response was to impose discriminatory, administrative transmission cost allocations for generation investment. In the end, FERC intervened, recognizing that what was required was a more comprehensive market redesign. As a result, New England switched to the revised PJM market design, even to the point of using the same dispatch and LMP pricing software.[82]

The California case, discussed further in Appendix C, followed a parallel process with another Enron-led coalition arguing for bilateral contracts with a highly constrained balancing market and no effective spot market transactions. The resulting approach required repeated reforms until FERC concluded in 1999 that the basic design was "fundamentally flawed" and required a comprehensive market reform.[83] Although recognized and launched before the outbreak of the California crisis, the reform analysis was taken up again later and led to a new market design based on the LMP model now used by eastern RTOs.

Subsequently Texas, although innovative in the development of its retail market, embraced many of

79 CRA International, Resero Consulting , "Update on the ERCOT Nodal Market Cost-Benefit Analysis," December 18, 2008, (www.puc.state.tx.us).
80 Not all RTO regions meet the same test of open access and non-discrimination. Alberta and Ontario are examples of RTO-co-ordinated markets that do not use the LMP model and suffer the problems of restrictions on access and discriminatory pricing.
81 Hogan, "Reforms of Reforms," pp. 121-123.
82 Hogan, "Reforms of Reforms," pp. 123-124.
83 Hogan, "Reforms of Reforms," pp. 126-130.

the flawed elements of the original California wholesale market design with a zonal spot market and an emphasis on bilateral transactions. The results in Texas paralleled equivalent parts of the California experience. Since ERCOT, the Texas version of an RTO, is not subject to FERC jurisdiction, the ERCOT case demonstrates that FERC participation is not the explanation of failed market designs. And when Texas reconsidered, the final order was for implementation of an LMP-based system that moved in the opposite direction of the contract-scheduling model.[84]

The RTO-coordinated markets that from inception successfully provided open access in a non-discriminatory manner, such as MISO and NYISO, were LMP-based markets that arose from adherence to the laws of physics and basic economic principles. There was no need to enforce reliance on contract schedules and a restricted spot market, and the implosions elsewhere were avoided.

The evidence is clear that every attempt to provide transmission open access under principles of non-discrimination without using the organized, open spot market based on the LMP design has failed. These failures have been dramatic and unambiguous; the results overwhelm any simple quantitative cost-benefit assessment. Comparing hypothetical RTO models that cannot meet the objectives of open access and non-discrimination, with a proven model that does meet these objectives, is not cost-benefit analysis; it is tantamount to comparing good apples to bad oranges. The organized wholesale markets provide substantial benefits greater than the costs, and the combined weight of the evidence points not to restricting the functionality of these markets but to improving the market design in directions quite opposite of the main thrust of the APPA critique.

84 Public Utility Commission of Texas, "Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas," Project No. 26376, September 22, 2003.

Appendix B: The Contract-Scheduling Structure Would Impose Major Costs on RTO Regions

In *Consumers in Peril*, APPA criticized RTOs for using generator bids and competitive auctions to arrange the dispatch. They also faulted RTOs for using market-clearing prices based on locational marginal costs (LMP) to price dispatch services. But every RTO uses bids, auctions and market-clearing prices to arrange and sustain a reliable dispatch.

Every system operator strives to achieve an "economic" dispatch, which requires the operators to select and dispatch the lowest-cost set of dispatchable generators and loads at each moment. RTOs must use a "bid-based" auction system because they do not own generation; they need each dispatchable generator's offer prices and each dispatchable load's bid information to arrange an efficient ("least-cost") and reliable dispatch. LMP clearing prices then reflect the bid-based marginal cost of the dispatch in each dispatch interval, at each location, thus providing dispatched generators and loads with the correct incentives to follow dispatch instructions.[85]

Some entity(ies) must perform the dispatch function, and there must be some means to encourage generators and loads to follow dispatch instructions, but without these proven methods of offers, bids and market-clearing prices that reflect the marginal cost of meeting load at each location, no RTO could do so. Therefore, under the contract-scheduling approach, some other entity(ies) would have to perform this function.

Dismantling RTOs Would Incur a Multi-Billion Cost of Reacquiring Capacity

If critics were to succeed in eliminating RTO "bid-based" auctions for dispatch and locational marginal cost clearing prices, the dispatch would have to be performed by some other entity(ies) that owned or controlled sufficient generation to perform the dispatch function. Each dispatch entity would need the authority to ensure generator compliance with dispatch instructions and to overcome the perverse incentives provided by prices that do not clear markets. Vertically integrated utilities that both operate the dispatch and own their own generation fit that description.

Each entity controlling the dispatch would be required to own or have under its control sufficient generation to sustain a reliable dispatch. Each utility's dispatchers would obtain the information required to arrange and implement a dispatch from its own generators (and any other generators under its control), and would then direct those generators to follow dispatch instructions. The generators would do what they were told, since they were owned or controlled by the same entity that controlled the dispatch. In this framework, the entire region now served by PJM would need to reassemble the pieces of vertically integrated monopoly utilities to make the structure work.

APPA's original proposals eventually would have required the region to disband the regional dispatch function PJM now performs—that is, to dismantle the core function of the PJM power pool that has existed for decades—while requiring a number of large, transmission-owing utilities to perform separate dispatches in each sub-region or zone of PJM's footprint. The Day 1.5 proposals accepted the need to retain PJM's region-wide dispatch, but only for the time being and only to postpone immediate "transi-

85 When the transmission system faces congestion, the value of power is different at different locations, thus requiring an RTO to pay locationally different prices reflecting the marginal cost of serving load at each location. That system encourages all generators to follow dispatch instructions, a result essential for reliable operations. Failure to recognize these differences, such as by paying all generators the same price no matter where they are located, produces incentives to produce too much or too little at each location, while encouraging gaming of bid/offer prices. These problems with non-LMP systems have been widely documented in California and other systems that tried other approaches.

tion costs," not because APPA recognized the value of a regional pool-wide economic dispatch.[86]

Those who recall that a few of the RTOs (including PJM, New York and New England) evolved from power pools might ask why unraveling power pools is a logical consequence of the contract-scheduling model. The explanation is found in the national policy for transmission open access and non-discrimination. The old power pools functioned without an organized spot market, particularly without the associated locational prices and financial transmission rights. There was economic dispatch, but the benefits were shared by the member utilities through a complicated cost allocation scheme that required both closed access to third parties and discriminatory application. The old power pools cannot be reconstituted to preserve trading across vertically integrated utilities without abandoning the principles of open access and non-discrimination required under the Federal Power Act.

Several large utilities that were original members of PJM (*e.g.*, PPL, PECO, PSE&G) have long since spun off or divested all their generation. To make a utility-by-utility dispatch work again would first require those transmission-owning utilities that took over the dispatch function from PJM to reacquire generation from the current owners and thereby return to the vertically integrated utility structure prevalent in non-RTO regions of the US. It is never explained how this result could be achieved or how much it would cost.

In Appendix D, we provide a first-order estimate of the asset purchase costs utilities would face if they were forced to reacquire sufficient generation for a reliable dispatch. That estimate indicates the purchase costs for the PJM region would be more than $130 billion.

Limiting Transmission Access Would Increase Costs of Serving Load

The reemergence of separate, sub-regional dispatches by transmission-owning utilities would also have cost consequences for parties seeking to contract for inter-regional trades. With multiple dispatch zones, inter-regional trades would become more difficult and costly to arrange. Equally important, each zonal dispatch entity would be functioning under transmission access rules and physical rights regimes that would reduce parties' ability to gain access to the grid to implement their contract schedules. With reduced trading and higher costs, electricity prices would rise throughout the region.

The ability to make economic trades across dispatch boundaries is partly a function of how well trading parties discern feasible and economic opportunities in the face of unpredictable transmission congestion. With multiple dispatch zones, each subject to separate dispatch, individual traders cannot easily determine which trades are feasible or profitable. However, if security-constrained economic dispatch is applied across the entire trading region, as occurs when an RTO assumes a regional dispatch over previously separate dispatch zones, then the RTO coordination can facilitate trading that might not otherwise occur from uncoordinated bilateral trading; as Mansur and White found when PJM expanded its RTO dispatch to include Midwest utilities, the net exports from the Midwest to the Eastern parts of PJM almost tripled.[87]

> "We find that these changes enabled the organized market to direct production to the most efficient available resources, realizing significantly greater gains from trade than occurred under the bilateral trading system."[88]

If restricted access to the RTO's spot market coordination would reduce trading, what impact would that have on electricity prices? To examine the effect of limited spot market access and the associ-

86 APPA leaves the status of PJM's "power pool" uncertain. *Kelly/Caplan* at 535. In PJM, "pool-wide" or regional dispatch simply means that PJM arranges a dispatch to match supply from anywhere in the region with demand for the entire region. Participation in this pool-wide dispatch is voluntary and LSEs can meet their loads through self-supply or bilateral schedules. PJM does not require that every generator in the region submit to its dispatch; generators can choose to submit fixed schedules for their operations. PJM arranges the dispatch to accommodate these fixed schedules.

87 Mansur and White, Figure 2.

88 Mansur and White, at 2.

ated contract-scheduling proposals on prices, Ventyx performed a study for the region defined by the boundaries of PJM's RTO. Using a commonly accepted production cost model (PROMOD IV) to simulate how the system would operate (and set prices), Ventyx compared what electricity prices would be under PJM's current framework and market rules (PJM "as-is" case) and what they would be under a market/industry structure consistent with the contract-scheduling approach.

The alternative case assumes utility regions that joined PJM in recent years return to their pre-RTO status, when they functioned as vertically integrated utilities. This results in 14 different dispatch zones. Six of these zones correspond to the service areas of Commonwealth Edison, AEP, Allegheny, Dominion, Dayton and Duquesne, which are the six utilities that joined PJM since 1997 and turned over dispatch operations to PJM to create a much larger regional power pool. The other eight zones consist of the service areas of the transmission owners who created PJM decades ago.[89]

Sub-regional dispatches would be more costly than a larger regional dispatch. And acquiring transmission rights across multiple utility dispatch zones would increase transaction costs, reduce transmission usage and limit trading. Ventyx examined how much energy production costs and inter-utility trading costs would increase for this alternative scenario compared to the current PJM "as-is" case.

Taking a conservative view of the additional hurdles to least-cost operations and inter-area trading imposed by this contract-scheduling framework, Ventyx found that the costs would increase by at least $2.47 billion in energy costs alone over the next 10 years, compared to the current PJM "RTO as is" case. If the PJM electric demand consumers were paying market prices for all of their energy requirements, their energy purchase costs could increase by over $1.3 billion per year, or $13.6 billion over 10 years. These results are explained further in Appendix E.

89 We assume that this level of pool dismemberment would be sufficient to create enough utility dispatch zones. However, it is possible that further disaggregation would be necessary.

Appendix C: Experience From California to New England Shows The Risks of Restricting Access to RTO Spot Markets

Proposals for restricting the ability for market participants to transact in centrally coordinated markets are familiar: Enron made them in the mid 1990s, beginning in California, and then in New York and PJM. That history is important, because the contract-scheduling features Enron advocated led to systemic failure, yet the same arguments keep recurring at different times and in different forums.

Such proposals were first made by Enron and its allies in California when the original rules for the California ISO and Power Exchange (PX) were being debated in 1994-96. Initially, Enron opposed creating a regional pool to serve California and even opposed having an Independent System Operator (ISO) operate the pool. Enron and other advocates of an unfettered, decentralized market preferred to leave the dispatch function dispersed among the individual utilities.[90] However, during the stakeholder process, it became apparent that a regional pool could reduce costs, and that the pool would need to be independently operated to avoid discrimination.

Like today's critics of RTO spot markets, Enron then proposed that the ISO perform only a limited balancing function. As a trader and middleman, Enron preferred a system in which load-serving entities relied almost exclusively on bilateral trading to match supply and demand. The limited balancing mechanism would handle final adjustments of the generation plant dispatch and would charge scheduling parties for minor deviations from the fixed schedules associated with parties' bilateral contracts. There would be no organized day-ahead market; Enron argued that competitive traders would efficiently handle all forward trading.

If the Enron approach had adhered to the principles of open access and non-discrimination, with no cross subsidies between parties, and no limits on the parties' ability to rely on the dispatch for balancing when it was economic to do so, this approach could have led to the same outcome as the regional pooled dispatch and associated spot markets operated by RTOs today. However, this would have required that parties' access to the ISO's dispatch not be arbitrarily limited and that the spot prices from using the dispatch reflect marginal costs of the dispatch used to balance the system and manage congestion.[91]

In 1995, the California Public Utilities Commission directed its jurisdictional (investor-owned) utilities to create an ISO, which would operate a regional pool dispatch for the state's three investor-owned utilities. The ISO would manage a bid-based real-time dispatch (and associated balancing or spot market), while another new entity, the Power Exchange (PX), would coordinate a day-ahead market through which the utilities would buy and sell the energy they needed to match their expected loads. The PUC's 1995 order did not limit access to the ISO's dispatch and associated spot markets, but the PUC left important details of market design to a stakeholder process dominated by the utilities, industrial customer groups and Enron.

90 *Initial Comments of Enron Power Marketing, Inc. In Response to California Public Utilities Commission's Order Instituting Rulemaking and Order Instituting Investigation*, June 8, 1994, filed in Dockets R.94-04-031 and I.94-04-132; also, hearing testimony of Enron's Jeff Skilling before the California Commission on August 4, 1994 (transcript at 1136).

91 William W. Hogan, *Economic Dispatch, Transaction Accounting and the OPCO or POOLCO Model*, August 31, 1994, prepared for the California Public Utilities Commission and restructuring working groups during consideration of alternative models for an independent system operator. For an explanation of why open access to an ISO's dispatch (and resulting spot market) is essential to support bilateral contracting, see Hogan's *An Efficient Bilateral Market Needs a Pool*, testimony submitted to the California Public Utilities Commission, August 4, 1994 in Dockets R94-04-031 and I.9404-132. The principles explained in these and related papers from that era would eventually become the foundation for all ISO/RTO markets. The papers are available at: www.whogan.com.

Enron and other energy marketers vigorously opposed integrating the operations of the ISO and PX.[92] During the development of market rules, they insisted that the separate PX manage the day-ahead market independently of the ISO, because they feared most trading would occur day ahead in the PX's bid-based auctions without the need for marketers. But having a PX separate from the ISO would eventually prove unworkable, because day-ahead schedules accepted without regard to congestion would prove to be infeasible in real time. The proposal was never implemented in practice. The ISO quickly determined that the Enron approach would compromise its ability to manage congestion and keep the lights on. This is the same reason that advance scheduling of contracts without RTO spot market coordination would be problematic.

Once California decided to create an ISO, Enron advocated limiting the ISO's spot market to a narrow "balancing mechanism," just as today's RTO critics urge today. While Enron argued publicly that forward contract markets could achieve more efficient results than the ISO, it was also true that limiting access to the ISO would benefit Enron. If access to the ISO's balancing mechanism could be constrained, and traders penalized for using it, traders could be forced to turn to Enron or other marketers to provide services they could not easily obtain from the ISO.

To limit the efficiency of the ISO's real-time dispatch and discourage its use, Enron also pushed for rules to prevent the ISO's central dispatch from achieving least-cost results. Astonishingly, Enron and its allies convinced enough California parties and FERC that in order to limit the ISO's balancing market, the ISO should be restrained from pursuing the lowest cost dispatch solutions to congestion and balancing, imposing a rule that *by design* raised costs and complicated reliable operations. This rule persisted through the energy crises in 2000-2001; it took years to remedy this design flaw.

Why did California regulators and FERC accept such obviously anti-consumer restrictions on the ISO? Enron argued that "the market" would function better if the ISO's market coordination was deliberately restrained and made inefficient, so as to create arbitrage profit opportunities for marketers and strategically located parties. These parties, Enron claimed, would produce lower cost results through unfettered marketer trading than the ISO could achieve through regionally coordinated least-cost dispatch. Of course, there was no evidence or theory to support Enron's claims, and simple economic logic would lead to the conclusion that a higher-cost dispatch would actually enable and shield higher-cost contract trading. Nevertheless, parts of Enron's design for California won the day in 1996.

The results were both predictable and predicted: a compromised ISO dispatch that struggled to maintain reliable operations while suffering higher costs, exacerbated by manipulation and bid gaming from savvy marketers and strategically located generators.

With some exceptions, the eastern ISOs avoided California's flawed designs, insisting instead that the ISO be required to operate a security-constrained economic dispatch. In such a dispatch, the ISO is obligated to select and dispatch the lowest-cost mix of generators to balance the system and meet all transmission safe operating limits. To be sure, Enron representatives and others made the same arguments in the East that they made in California,[93] but their proposals for a "limited balancing market" were rejected by the parties supporting the original PJM and New York ISOs. The New York ISO began operations with locational marginal pricing, over Enron's objections;[94] after an initial wrong turn down the path espoused by Enron, PJM began using LMP in 1998. Since then, other US RTOs eventually followed the New York and PJM models. Together, the improved designs have allowed the Eastern ISOs to maintain reliable operations and pursue economic dispatch solutions to the complicated physical issues that characterize electricity grids.

92 *Comments of Enron Capital & Trading Resources, et al on the Memorandum of Understanding Filed September 11, 1995*, filed October 2, 1995, in Dockets R.94-04-031 and I.94-04-132.

93 See, *e.g.*, Initial Comments of Enron Capital & Trade Resources on the Optimal Model for New York State's Electric Industry, submitted October 24, 1995, to the New York State Public Service Commission in PSC Case NO. 94 — E — 0952.

94 California rejected LMP and instead adopted a compromised spot pricing regime that was easily and repeatedly manipulated, with Enron inventing various gaming strategies to create artificial congestion and be paid to relieve it. Later reforms emphasized the need to implement the LMP model.

Proposals similar to Enron's have been discredited for nearly a decade, not merely because of California's experience with flawed designs, but also because no one has ever demonstrated how an ISO/RTO can facilitate forward contract scheduling and ensure open, non-discriminatory access without the core elements that RTO market opponents seek to eliminate. Ample experience has shown there are no workable solutions consistent with those goals without organized spot markets using bid-based security-constrained, economic dispatch and locational clearing prices, the core features of the RTO organized markets. And opponents have failed to describe any workable alternative that supports both market and regulated environments, while meeting the federal statutory requirement to support competition and provide non-discriminatory, open access to transmission.[95] This flexibility is a necessary requirement, because the highly interconnected eastern grid encompasses both traditionally regulated states (*e.g.*, Indiana) and "restructured" states (*e.g.*, New Jersey and Pennsylvania) with many variations in LSEs and generation ownership.

The eastern RTOs are not unique in coming to this conclusion. Every RTO in the country eventually arrived, voluntarily and through its own history, at the same conclusion. One finds the same core elements of bid-based, security-constrained economic dispatch with locational prices in PJM, the New York ISO, and the New England ISO; the same features appear in the revised rules at the California ISO, ERCOT,[96] and the rules developed by the newest RTOs: the Midwest ISO and (with some exceptions) the Southwest Power Pool. Today, more than two-thirds of electricity consumers function under this framework.

RTO market critics who seek to alter or compromise the core elements of RTO regional dispatch and associated markets have a burden to show they are at least compatible with the underlying physical requirements of grid operations and can achieve the economic benefits of efficiently priced pooled dispatch without discriminating against some users and/or creating barriers to entry.

95 William W. Hogan and John D. Chandley, *A Path to Preventing Undue Discrimination and Preference in Transmission Service*, comments submitted to the Federal Energy Regulatory System, August 2, 2006; this and follow-up papers on how RTOs provide open access are available at: http://ksghome.harvard.edu/-whogan/

96 Note that ERCOT, the ISO for most of Texas, arrived at the same conclusion even though ERCOT is not subject to FERC jurisdiction. California, New England and Midwest ISO independently adopted the basic PJM/New York design after watching their original alternative models undermine reliability.

Appendix D: Estimated Costs of Reacquiring Generating Capacity

In order to implement limited spot market access and the associated contract-scheduling structure, it would be necessary to purchase the fleet of generators in the PJM control area that are not already owned by public power or the regulated portions of investor-owned utilities. As we explain further in Appendix F, in order to purchase a generator, it will be necessary to pay its owner an amount sufficient to induce it to give up its rights to (1) the net energy revenues that generator would otherwise be expected to earn (defined as energy revenues net of the variable costs it incurs to produce energy), plus (2) the capacity revenues it expects to earn, minus (3) the fixed costs the owner of that generator incurs to make it available for operation, but which could be avoided if the generator were shut down.

One approach to estimating the value of these generators is to estimate the present value of each of these three cash streams for each generator in the PJM control area that would be purchased to implement the structure. However, given the large number of generators to be valued, that would be extremely difficult. Instead, we have applied a simplified approach to value these generators, which builds upon work performed by Levitan and Associates Inc. (LAI) in a study performed for the Maryland Public Service Commission. In that study, LAI stated, "The current fair market value of Maryland's power generators is at least $18 billion."[97] Based on LAI's valuation, and on an assessment of the impact that differences in generating technology, location, age, generating capacity and outage rates would be expected to have on the value of the revenue streams that each generator would be expected to realize (and hence the cost of purchasing each of those generators), we estimated the value of each generator in PJM that would have to be purchased.

Using this simplified approach, we estimated the cost of purchasing those generators at $133 billion. While a plant-by-plant evaluation of each of the cash streams described above would provide a more accurate assessment of this cost, this estimate realistically conveys a sense of the approximate cost that would be incurred to purchase this amount of generating capacity. The remainder of this appendix describes the methodology we used to calculate that estimate.

Factors That Affect Generator Value

There are five primary factors that affect the revenue streams that generator owners receive, and hence the amount that a generator owner would require in order to sell it:

- **Generating Technology.** Since baseload generators can produce energy at very low variable costs, they can produce a given MWh less expensively. They also are called upon to operate more often than other, more expensive plants. Both of these factors cause the net energy revenues that baseload generators earn, stated in terms of dollars per MW of capacity, to be higher than the net energy revenues that other generators earn. The capacity revenues that different generation technologies earn should be about the same (holding everything else equal), since capacity markets do not differentiate between different generation technologies. Therefore, the revenue stream that baseload generators realize will generally be larger than the revenue stream that other generators realize, so it will cost more to purchase a baseload generator of a given size than to purchase other generators of that size. For similar reasons, it is less expensive to purchase peaking generators, whose variable cost of generating energy is high, than it is to purchase intermediate generators, whose variable cost of generation is between the costs of baseload and peaking generators.

- **Location.** Energy prices vary from location to location within PJM, because PJM uses locational pricing. Under locational pricing, the price of energy at each location reflects the marginal cost of producing additional energy at that location. When there is transmission congestion that restricts

97 Kaye Scholer LLP, Levitan & Associates, Inc. and Semcas Consulting Associates, *State Analysis and Survey on Restructuring & Re-Regulation*, in Response to Task #2 Request for Proposals PSC #01-01-08, November 30, 2007, at 69.

the amount of inexpensive generators at one location to serve the needs of consumers at another location, thereby making it necessary to operate more costly generators to meet those consumers' needs, the price of energy in the second location will exceed the price of energy at the first location. Likewise, capacity revenues may also vary locationally, since they are based on the cost of developing capacity, which can vary from one location to another. Therefore, the net energy revenue and capacity revenue streams that a generator owner expects to realize may depend upon its location, so the cost of purchasing that generator may also depend upon its location.

- **Age.** The owner of a generator that was built long ago and is approaching obsolescence, and that will only realize energy and capacity revenues for a few more years, will be willing to sell that generator for considerably less than a newer generator that will continue to produce energy and capacity revenues for many more years.

- **Generating Capacity**. Generators with more generating capacity are able to produce more energy, so they receive more net energy revenue; they also qualify for larger capacity payments, everything else held equal. Therefore, the revenues that the owner of a larger generator expects to earn will generally be larger than the revenues a smaller generator expects to earn, so the cost of purchasing larger generators is greater than the cost of purchasing smaller generators.

- **Outage Rate.** Finally, generators that are more frequently unavailable will realize fewer energy revenues. They will also realize fewer capacity revenues, since unforced capacity, which incorporates a correction to account for unplanned outages, is the metric that is used in PJM to determine the amount of capacity a generator is permitted to provide. Consequently, all else held equal, generators that are more frequently out will sell for less than other generators.

To estimate the cost of purchasing a given generator, it is necessary to take the impact of these five factors on its value into account.

Adjusting for Differences in Generating Technology

Over the long term, there is a certain average amount of revenue that a generator owner would have to expect to earn each year, below which it would not be willing to develop new generation. That amount of revenue is called the "levelized annual cost" of building that generator. PJM's market monitoring unit (MMU) has compiled statistics on the levelized annual costs of building generators using three different technologies. These are reported in the *State of the Market Report* the MMU issues each year. The results for 2005 through 2007 are as follows:

Levelized Fixed Costs for Entrants ($/MW-yr.)

Technology	2005	2006	2007	Average
Combustion Turbine	72,207	80,315	90,656	81,059
Combined Cycle	93,549	99,230	143,600	112,126
Pulverized Coal	208,247	267,792	359,750	278,596

Source: PJM Interconnection, *2007 State of the Market Report*, Table 3-22.

As this shows, while there is some movement from year to year, the cost of building a combustion turbine generator averages about 27 percent of the cost of building a combustion pulverized coal generator, and the cost of building a combined cycle generator averages about 41 percent of the cost of building a combustion pulverized coal generator. Consequently, on average, we would expect the sum of the net energy and capacity revenues that the owner of a combustion turbine would receive would be about 27 percent of the sum of the net energy and capacity revenues that the owner of a pulverized coal plant would receive, and the sum of the net energy and capacity revenues that the owner of a combustion turbine would receive would be about 41 percent of the sum of the net energy and capacity revenues that the owner of a pulverized coal generator would receive. If it were otherwise—for example, if the owner of a combustion turbine expected revenues that were 50 percent of the revenues that the owner of a pulverized coal generator would realize, in return for only spending 27 percent as much as the pulverized coal generator developer spends—then everyone would built combustion turbines and no one would build pulverized coal generators. This would progressively reduce the revenues that combustion turbines would receive, as compared to the revenues that pulverized coal generators receive, until the point where this disparity disappears.

Therefore, on average, combustion turbines (or other peaking generators) can be expected to earn net energy and capacity revenues that are about 27 percent of the net energy and capacity revenues that otherwise identical pulverized coal generators would earn, and combined cycle generators (or other intermediate generators) can be expected to earn net energy and capacity revenues that are about 41 percent of the net energy and capacity revenues that otherwise identical pulverized coal generators would earn. So the cost of purchasing peaking capacity would be expected to be about 27 percent of the cost of purchasing baseload capacity, and the cost of purchasing intermediate capacity would be expected to be about 41 percent of the cost of purchasing baseload capacity, all other things held equal.[98]

Adjusting for Differences in Location

In the 2007 State of the Markets Report, PJM's MMU also reported the sum of net energy revenue and the capacity revenue that an entrant generator using each of the three technologies above would have earned in each of the zones within PJM. This permits us to assess the impact that location has on the total revenue stream that a generator owner using a given technology would expect to realize; for example, in 2007, a new combustion turbine in the BGE zone would have been expected to earn $94,710/MW-yr. in net energy revenue and capacity revenue, while a new combustion turbine in the MetEd zone would only have been expected to earn $46,663/MW-yr., about half as much.[99] Therefore, if these sorts of revenue differences are expected to persist, one would expect the sale price of a generator in the BGE zone to be about twice the sale price of an otherwise identical generator in the MetEd zone.

Adjusting for Differences in Age

Different generators will have different lifespans, but the value of a baseload generator in a given location with only three years remaining in its lifespan is not simply one-tenth of the value of a baseload generator with the same capacity and at the same location that is expected to remain in service for another 30 years. That is because the value of a dollar in revenues that a generator owner expects to earn 30 years from now is considerably less than the value of a dollar in revenues that a generator expects to earn this year. Consequently, the value of a generator with only three years left in its lifespan is more than one-tenth the value of an otherwise identical generator with 30 years of life remaining. In fact, using an annual discount rate of 7%, the value of a generator with only three years left in its lifespan is about 21 percent of the value of an otherwise identical generator with 30 years of life remaining.

For the purposes of this analysis, we assumed that each generator would have a useful service life of thirty years starting with its in-service date. However, many generators are more than thirty years old. Therefore, we assumed a minimum value for the remaining lifespan of three year for all units other than nuclear generators. For nuclear generators, we assumed a minimum remaining lifespan of seven years,

98 For the purposes of this analysis, all steam turbines, the steam portions of combined cycle units, and all hydraulic turbines other than pumped storage were classified as baseload units; peaking units included all combustion turbines, internal combustion engines, and wind turbines; and intermediate units included all single-shaft combined cycles, combined cycles not otherwise broken down, pumped storage, and units not otherwise classified. Reclassifying non-pumped storage hydraulic turbines or wind turbines had little impact on the estimated cost of purchasing the generation fleet.

99 PJM Interconnection, *2007 State of the Market Report*, Tables 3-24, 3-26 and 3-28.

since it seems unlikely that many nuclear units will shut down in the next three years. This assumption produces a value for those units that is consistent with the $4.5 billion recently paid by Electricité de France ("EDF") for a 49.99 percent interest in Constellation Energy Nuclear Group ("CENG").[100]

Adjusting for Differences in Generating Capacity and Outage Rates

Finally, the amount of unforced capacity that a generator can provide reflects its generating capacity adjusted to account for its outage rate. The capacity revenues a generator earns will be directly proportional to the amount of unforced capacity it provides, and while the energy revenues it receives are not directly proportional to this amount, they should be roughly proportional (particularly since the adjustment to account for outage rates is typically not large). Therefore, the ratio of the amount of unforced capacity that two otherwise identical generators provided approximates the ratio of the cost of purchasing those generators.

Using these Adjustments to Derive the Total Purchase Cost

Since we know the generating technology, location and age of each generator in Maryland, as well as the amount of unforced capacity it can generate, we used that information to help us determine the cost of purchasing the fleet of generators in the PJM control area that are not already owned by public power or the regulated portions of investor-owned utilities. We calculated the value of each generator in Maryland given (1) the factors above, which establish the relative values of each of those generators given differences in generating technology, location, age, capacity and outage rate, and (2) the need for the sum of the values of Maryland generators to sum to $18 billion to conform to LAI's calculation.

Illustrative Example

Before we delve into the mathematical detail of the equations that were used to perform these calculations, an example illustrating the gist of the approach is likely to be useful. Consider the value of a combined cycle generator compared to the value of a pulverized coal generator, using the latter generator as a benchmark. For the purposes of this example, assume a combined cycle generator would be worth about 40 percent of the value of an otherwise identical pulverized coal generator. (The figure that we used is actually about 41 percent.) However, suppose that the combined cycle generator is in a location where its value is 120% of the value of the combined cycle generator in the location that was assumed when calculating the annual levelized costs of such a generator while the pulverized coal generator is in a location where its value is 80% of the value of the pulverized coal in the location assumed in when calculating the annual levelized costs of developing such a generator.

In that case, everything else is not equal, so it is not accurate to state that the value of the combined cycle generator is 40 percent of the value of the pulverized coal generator. Instead, once these locational adjustments are taken into account, the ratio of the value of the combined cycle generator to the pulverized coal generator increases from 40% to 40% x (120% / 80%) = 60%.

Similarly, assume that:

- Taking age into account leads to the conclusion that the value of the combined cycle generator is twice the value of an otherwise identical pulverized coal generator.

100 The $133 billion cost of purchasing non-utility-owned generation in PJM includes $4.06 billion for the purchase of CENG's Calvert Cliffs units. Calvert Cliffs represents about 44.5 percent of CENG's capacity, the remainder of which is in New York and which therefore was not included in our study. However, if we assume that the New York capacity is just as valuable on a per-MW basis as the Calvert Cliffs capacity, then the value of all of CENG's capacity would be $4.06 billion / 44.5% = $9.12 billion, so the value of EDF's share of CENG is $4.56 billion, approximately equal to the $4.5 billion paid by EDF.

- The combined cycle generator provided 100 MW of unforced capacity, while the pulverized coal generator provided 300 MW of unforced capacity.

Adding the impact of these two factors to the locational and technology adjustments described above leads to the conclusion that the value of the combined cycle generator should be 60% Ð (1/2) Ð (1/3) = 10% of the value of the pulverized coal generator. Therefore, if the total value of the two generators was assumed to be $330 million, it would be appropriate to assign a value of $300 million to the pulverized coal generator and a value of $30 million to the combined cycle generator.

Implementation

We implemented this approach using the following three-step procedure:

1. We calculated the amount of normalized capacity that each generator provided. Normalized capacity is the amount of unforced capacity a generator provided, adjusted to account for the impact of that generator's technology, location and remaining lifespan (each as compared to a benchmark generator) on its value, as described above. Therefore, the ratio of two generators' normalized capacities should reflect the ratio of their values.[101]

2. Next, we divided the $18 billion value of the Maryland generation fleet estimated by LAI by the number of MW of normalized capacity in that fleet to determine a value per MW of normalized capacity.

3. Finally, we multiplied the amount of normalized capacity provided by each generator to be purchased and the value per MW of normalized capacity that was consistent with LAI's valuation of the Maryland fleet, and summed the result over all generators that would have to be purchased.

The number of MW of normalized capacity that each generator provided was calculated using the following equation:

$$NCAP_{g,t,z} = UCAP_g \cdot TNF_t \cdot ZNF_{t,z} \cdot LNF_g$$

where:

$NCAP_{g,t,z}$ is the normalized amount of capacity provided by a generator g of technology type t located in zone z;

$UCAP_g$ is the amount of unforced capacity provided by generator g, as reported in the 2008 PJM Load, Capacity and Transmission Report, Sch. 3, Part D;

TNF_t is the technology normalization factor for generators of technology type t;

$ZNF_{t,z}$ is the zonal normalization factor for generators of technology type t located in zone z; and

LNF_g is the lifespan normalization factor for generator g;

$TNFt$ was calculated as the ratio of the levelized fixed cost of an entrant using technology type t averaged over 2005-07, as reported in Table 3-22 of the *2007 State of the Market Report*, to the levelized fixed cost of a pulverized coal plant over that time period as reported therein;

101 In the illustrative example, using a pulverized coal generator receiving the average level of revenue in PJM as the benchmark, the combined cycle generator would have provided 100 MW x 0.4 x 1.2 x 0.5 = 24 MW of normalized capacity (with the adjustments respectively reflecting the impact of the combined cycle's technology, location and age on its value as compared to the benchmark generator), while the pulverized coal generator would have provided 300 MW x 1 x 0.8 x 1 = 240 MW of normalized capacity.

$ZNF_{t,z}$ was calculated as the ratio of the net revenue that would have been earned in 2007 by a generator in zone *z* using technology type *t*, as reported in Tables 3-24, 3-26 and 3-28 of the *2007 State of the Market Report*, to the average net revenue that would have been reported in those tables for a generator in PJM using that technology type; and

LNF_g was calculated using the following equation:

$$LNF_g = \sum_{i=1}^{RL_g} \frac{1}{(1+d)^{i-1}} \Big/ \sum_{i=1}^{30} \frac{1}{(1+d)^{i-1}},$$

where:

RLg, the remaining lifespan of generator g, is equal to the greater of (1) the number of years from Jan. 1, 2009 to a date 30 years after generator *g*'s in-service date, as reported in the 2008 PJM Load, Capacity and Transmission Report, Sch. 3, Part D; or (2) three years (seven years if generator *g* is a nuclear generator); and *d*, the real discount rate applicable to the cash flows resulting from generation ownership, was set at 7 percent per year.

The resulting valuation for each generator to be purchased is consistent with the each of the rules above, regarding the relative values of generators using different technologies, at different locations, of different ages, with different capacities, and with different outage rates, while also being consistent with the valuation that LAI calculated for the Maryland generation fleet. The $133 billion estimate of the cost of purchasing the non-utility-owned portion of the PJM generation fleet corresponds to a value of $1,123 per kW of capacity purchased; by way of comparison, LAI's calculation of the cost of purchasing the Maryland generation fleet corresponded to $1,390 per kW.[102]

102 Detailed calculations are included in an Excel spreadsheet available from the authors.

Appendix E: Estimate of Increased Energy Costs within PJM

In response to the APPA proposal to reform energy markets, Ventyx has performed a *pro forma* quantitative analysis of the PJM market, to attempt to quantify the increase in energy costs that would ensue as a result of this proposed unraveling of the integrated energy market.

This analysis focuses on a view of the PJM market for the nominal 2006-2007 market year. From its latest release of the Marketvision™ database, Ventyx has extracted the data required to represent the current PJM footprint. Using PROMOD IV®, Ventyx' commercial software simulation model for electric markets, Ventyx has represented the "As Is" PJM market for the June 2006 through May 2007 market year. A second simulation was performed, based on a representation of the effective market conditions in a Revised Market, consistent with the bilateral market envisioned by APPA.

Information regarding PROMOD IV is available on the web at:

http://www1.ventyx.com/analytics/promod.asp

Basic Data Assumptions

The "As Is" market simulation represents the existing PJM under a standard assumption of coordinated unit commitment and dispatch by the centralized RTO market.

The representation of the transmission system is based on a 2008 Summer Peak MMWG case, from the 2006 MMWG series of powerflow cases. For the portion of the transmission system outside of the PJM RTO simulation footprint, PROMOD IV scales the bus generations to match the total bus loads, so as to remove any net interchange between PJM and the non-PJM powerflow areas.

Hourly demands for each of the seven PJM zones reflect the actual zonal demands as posted by PJM.

The "PJM Classic" zone was divided into eight zones, consistent with the legacy investor-owned utility structure of PJM before market restructuring. This analysis, then, represented PJM as being composed of a total of 14 zones.

In performing its security-constrained unit commitment and dispatch, PROMOD IV monitors a prescribed set of contingency constraints, or flowgates, just as the actual markets are scheduled based on a defined list of commercial flowgates. For this study, PJM staff provided a constraint set that is used in similar in-house PROMOD IV analyses.

Natural gas and oil prices, as well as SO2 and NOx prices, matched contemporary commodity prices for the 2006-2007 simulation period.

For nuclear generating units, actual generator outages lasting one week or longer (primarily refueling outages) were directly specified in the data. All other generators' scheduled maintenance outages were scheduled internally by the model, based on a reliability levelization algorithm.

In order to capture cost impacts on a zone-by-zone basis, the PJM generating resources needed to be assigned to the different zones, more or less representing a vertically integrated traditional utility. The starting point for this assignment of generator "ownerships" is a spreadsheet that PJM provides, for use by market stakeholders in planning their FTR market participation. This spreadsheet identifies the historical generating resources of each zone, prior to implementation and expansion of the PJM market. The resource assignments to the zones resulting from this historical information were adjusted so that newer resources not represented in this spreadsheet would be assigned to capacity-deficient zones so as to result in a roughly equal summer peak installed reserve margin over the zones. The overall reserve margin for the simulation footprint is approximately 15%. The resulting reserve margins for the individual zones, after assignment of newer combined cycle and CT generators, are all in the range of 14%-15%.

Spinning reserve requirements were identified from the PJM market monitor's *State of the Market Report*. For the "As Is" simulation, this results in spinning reserve requirements primarily for the ComEd and MidAtlantic zones, plus a small requirement for the Dominion zone.

Revised Market Simulation.

The "Revised Market" scenario represents a market relying on bilateral energy trades. A market coordinator would ensure that these schedules satisfied transmission constraints. Finally, some entity would operate a real-time balancing market, the intent of which is to schedule for deviations from the submitted schedules. In *Consumers in Peril,* APPA originally proposed that this balancing market would clear no more than 5% of the energy in the overall market; in *Competitive Market Plan*, APPA continues to assume most trading would be done through bilateral contracts and not the spot market.

The world envisioned by APPA would comprise energy scheduling entities ranging from traditional vertically integrated utilities to retail LSEs. It is not possible to simulate how each of these entities would arrange their bilateral schedules in a real-world unstructured market. For purposes of this study, the "Revised Market" representation of the PJM zones assumes that each of these fourteen zones would operate as the equivalent of a traditional control area, with centralized commitment and dispatch of generating resources within the zone. This is a conservative assumption with regard to energy costs of the actual scheduling entities within the zone, because it assumes that any implied market inefficiency due to the independent scheduling by the zone's members could be resolved by this coordinated dispatch within the zone.

From a modeling perspective, the diminished efficiency (higher energy production cost) of a bilateral market is due to three primary factors. First, the bilateral energy scheduling process is less efficient than the schedules derived by a centralized LMP market. This energy market inefficiency is manifested as an implied hurdle rate for scheduling economic interchange among the zones. These hurdle rates have physical components, such as the OATT through-and-out rate that must be charged to schedule a firm energy transfer, as well as out-of-pocket trade execution costs. Additionally, there is a significant non-physical component to these hurdle rates, reflecting the market inefficiencies related to a lack of price transparency and centralized market clearing.

Because scheduling firm, day-ahead transactions bears a higher cost (firm transmission charges, no centrally cleared day-ahead market), a higher hurdle rate between the zones is assumed for purposes of unit commitment than is used for the hourly non-firm interchange. Various RTO cost/benefit studies that have been performed in recent years have assumed a range of values for these hurdle rates. In 2003, Cambridge Energy Research Associates (CERA) performed a cost/benefit study for AEP's entry into the PJM market. In that study, CERA used a commitment hurdle rate of $7.25, and a dispatch hurdle rate of $4.25. Although CERA states that these hurdle rates were derived from a benchmark to historical market conditions, these rates (in particular, the commitment hurdle rate) are somewhat lower than some other calibrations. For this study, Ventyx has used a dispatch hurdle rate of $5, and a commitment hurdle rate of $8, although other calibrations suggest that a commitment hurdle rate in the range of $10-$12 might be appropriate.

The second source of inefficiency in the bilateral market is congestion management. In the LMP market, PJM schedules energy flows up to the physical flowgate limits. In a bilateral market, these flows are limited by the ATC limits posted on the OASIS sites, which reflect derations (?) for such factors as TRM. Furthermore, a security coordinator reviews actual schedules to determine their combined feasibility under current conditions, and must curtail schedules on a non-economic priority basis when infeasible flows are anticipated. APPA recognizes that this function would still need to be performed by a security coordinator in the bilateral market that it proposes.

As part of a series of cost/benefit studies performed with MISO in recent years, historical TLR records were reviewed, to determine the impact of the inefficiencies of TLR congestion management. For Level 3 TLR curtailments that had occurred over several years, the actual flows scheduled after curtailment were compared to the nominal limits that were used to apply the curtailments. For transmission in the ECAR and MAIN regions, it was found that TLR curtailments resulted in a 9% under-utilization of the transmission flowgates. Consistent with these previous studies, Ventyx has applied this 9% deration to the flowgate limits in the "Revised Market" scenario.

The third market characteristic that introduces inefficiency in the bilateral market is decentralization of ancillary services. In this study, Ventyx has assumed that the total ancillary services (spinning reserves and load-following) would remain the same. However, in the "Revised Market" scenario, the MidAtlantic spinning reserves were allocated over the Reliability First zones in proportion to their non-coincident annual peak loads.

Measure of Increased Energy Costs

For the total PJM footprint, the increase in energy supply cost due to revising the market is simply the change in energy production costs of the resources in the market. In order to identify the change in costs zone by zone, it is necessary to adopt a definition for the prices paid within the market for energy exchanges. For this and similar studies, Ventyx has assumed that a zone that is buying in an hour will pay its purchased energy times its generation-weighted zonal LMP. These revenues are then allocated over the sellers in proportion to their sold energy times their generation-weighted zonal LMP in the hour. The resulting "adjusted production cost" is used as the zonal cost measure for the analysis.

Alternative measures of the increase in cost are the change in generator revenues and the change in load payments.

The estimated annual increase in energy costs are:

	Adjusted Production Cost	Generator Revenues	Load Payments
AEC	$6,375,371	$41,949,138	$41,555,752
AEP	$5,286,571	-$397,463,001	-$162,736,564
Allghny	$30,777,824	$3,792,891	$301,899,006
BG&E	$36,588,624	-$3,650,568	$108,967,851
ComEd	-$57,700,762	-$276,402,171	-$155,260,602
Dayton	$8,759,490	$45,857,962	$41,375,117
Dominion	$52,332,676	$766,995,222	$459,796,530
DPL	$32,912,194	$135,573,670	$90,278,689
Duquesne	$7,482,096	-$10,859,380	-$16,569,218
FE	$22,646,014	$59,254,467	$172,473,389
PECO	$706,893	-$34,955,280	$28,938,435
PEPCO	$60,815,115	$218,849,693	$246,932,591
PPL	$10,371,573	-$78,825,134	$28,960,383
PSEG	$29,929,899	$244,326,418	$174,651,798
Total PJM	**$247,283,578**	**$714,443,927**	**$1,361,263,157**

This analysis indicates that, over ten years, the increase in energy costs due to reliance on a bilateral market would be $2.5B, measured as adjusted production cost, or as much as $13.6B, measured as increased load payments.

Appendix F: APPA's Proposals Would Not Save Money On Capacity Costs

In the several RTO-administered markets, including PJM, independently owned generators realize two main sources of revenue. First, they sell energy to the market. Second, they sell capacity into capacity markets, such as PJM's RPM. (They may also earn revenues from the sale of ancillary services, but those are relatively minor for most generators and will be disregarded for the balance of this discussion.)

There are costs involved in operating a generator. Some of those costs (primarily fuel costs) are directly related to the amount of energy that a generator produces, so they could be avoided if a generator were to shut down. In addition, other costs, such as the labor costs associated with staffing a generator, are not directly related to energy production, but could also be avoided if a generator were shut down. But to the extent that the energy and capacity revenues paid to generators exceed the sum of these avoidable costs, the difference accrues to the owners of those generators.

If these generators were instead paid on an embedded cost basis, end-use customers would no longer have to pay this difference. Instead, they would only need to cover the costs that are directly associated with generating energy and the other costs associated with operating a generator. Consequently, it is tempting to conclude that this difference between the market-based revenues that generator owners earn and the avoidable costs associated with operating a generator represent an amount that could be saved by returning to the vertically integrated paradigm.

But this analysis overlooks a vital element: The cost of purchasing those generators from their owners. To the extent that the energy and capacity revenues that a generator owner expects to receive exceeds the costs it expects to incur as a result of operating a generator, that generator owner will require a payment that is sufficient to compensate it for foregoing that difference. If that payment is financed over time, the cost of purchasing those generators will not be substantially different from the cost of making energy and capacity payments to the owners of those generators under the current market structure. Therefore, this potential source of savings from returning to the vertically integrated paradigm is illusory.

To illustrate, suppose for simplicity that a generator has an anticipated lifespan of three years. It expects to realize $500 million in revenues from the sale of energy in the first year, and the cost of generating that energy is expected to be $350 million. It also anticipates $100 million in capacity revenue that year, and $50 million in other operating costs, so the total operating profit it expects to realize in that first year is $500 million + $100 million – $350 million – $50 million = $200 million. All costs and revenues are expected to increase at a rate of five percent per year. Therefore, the generator expects to realize operating profits of $631 million over its lifespan, as calculated in the table below.

Anticipated Operating Profit Over Hypothetical Generator's Lifespan

	Year 1	Year 2	Year 3	Total
Energy Revenues	500	525	551	1,576
Capacity Revenues	100	105	110	315
Total Revenue	600	630	662	1,892
Cost of Generating Energy	350	368	386	1,103
Other Operating Costs	50	53	55	158
Total Operating Costs	400	420	441	1,261
Operating Profit	200	210	221	631

Suppose the restructuring rules required each utility to build or purchase sufficient generation to cover its own loads plus planning reserve requirement. The amount required to purchase this generator from its owner should be less than $631 million, as the owner prefers a dollar now to a dollar to be realized two years from now. Assume, again for the purposes of illustration, that the owner of the generator expects to be able to realize ten percent per year in returns on if it invests the revenues it receives in exchange for selling the generator. Then it would be willing to accept 90 cents in Year 1 to give up a dollar in operating profit that it expects to earn in Year 2, and 81 cents in Year 1 to give up a dollar in operating profit in Year 3, so it would be willing to sell this generator for $573 million (payable in Year 1), as shown by the table below.

Anticipated Discounted Operating Profit Over Hypothetical Generator's Lifespan

	Year 1	Year 2	Year 3	Total
Operating Profit	200	210	221	631
Discounted Operating Profit	200	191	182	573

The $573 million cost of purchasing this generator could be recouped in many different ways, over many different time periods, but the most natural assumption is to assume this cost would be recouped over the time that the generator is expected to operate, since recouping it over a shorter time period would mean that consumers in earlier years were subsidizing consumers of energy in later years, and recouping it over a longer time period would have the reverse implication. One way of collecting this cost from end-use customers over the generator's lifespan would be to collect $200 million in Year 1—which was the operating profit the generator expected to earn in that year—while financing the remaining $373 million purchase price. One year later, the amount to be paid off would have increased by 10 percent, from $373 million to $410 million. If $210 million (which was the operating profit the generator expected to earn in Year 2) is recovered from end-use customers in Year 2, that leaves $200 million to be financed. In Year 3, that amount will have grown from $200 million to $221 million, which would be recovered from end-use customers in that year. This is illustrated in the table below.

Schedule for Recovering Purchase Cost from End-Use Customers

	Year 1	Year 2	Year 3
Total Amount to Recover	573	410	221
Recovered from End-Use Customers	200	210	221
Amount to Be Financed	373	200	—

The important thing to note is that the total amounts that end-use customers pay in each year are the same, regardless of whether customers pay the energy and capacity market payments or the generator is purchased and customers pay its operating costs plus the purchase and financing costs, as the table below illustrates. If the generator is not purchased, end-use customers will pay the generator for energy and capacity. If the generator is purchased, end use customers will pay the generator's operating costs. The difference between the generator's energy and capacity revenues and its operating costs is its operating profits, so end-use customers would not have to pay the operating profits. But these savings must be offset against the cost of purchasing the generator. Since the value of the generator to its owner is the value of the operating profits it is expected to produce, the cost of purchasing it is the value of those operating profits. As a result, the cost of purchasing the generator offsets operating profits exactly.

Comparison of Payments by End-Use Customers

	Year 1	Year 2	Year 3
Energy Payments	500	525	551
Capacity Payments	100	105	110
Payments by End-Use Customers if Generator is Not Purchased	600	630	662
Cost of Generating Energy	350	368	386
Other Operating Costs	50	53	55
Cost of Purchasing Generator	200	210	221
Payments by End-Use Customers if Generator is Purchased	600	630	662

(Endnotes)

1 John D. Chandley is a Principal at LECG, LLC. William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. Preparation of this paper was supported by the COMPETE Coalition. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), Exelon, GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PPL Corporation, Public Service Electric & Gas Company, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, TransÉnergie, Transpower of New Zealand, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the authors. (Related papers can be found on the web at www.whogan.com

Appendices D and F were prepared by Michael D. Cadwalader, a Principal at LECG. Appendix E was prepared by Ventyx under the direction of James Sustman.

Attachment 9

Residential Customer Switching Drives Big Upsurge in Retail Electricity Competition

Retail electricity competition is poised for tremendous growth, and increased shopping by residential customers is behind the huge growth surge, **DNV KEMA**, a leading electric industry consulting firm, reported in a new analysis.

Competitive retail suppliers are jumping into the marketplace in increasing numbers and offering price-saving deals to residential and other small customers, priming the pump for continued healthy growth in retail electricity market competition, the DNV KEMA analysis found. Residential and small commercial competitive market sales grew by 19% over the past year, and DNV KEMA expects that trend to continue over the next 12 to 18 months.

"Our analysis shows that retailers are seizing opportunities created by increased margins in these smaller markets," Sonny Kanlier, Vice President, DNV KEMA's Retail Energy Markets, said in a **press release**.

A substantial increase in competitive retail suppliers entering restructured markets signals that residential and small business markets are going to heat up, DNV KEMA said. Competitive retailers are offering savings compared to the regulated utility rate, and customers are paying attention, the company said.

"This is indeed an interesting dynamic," Hugo van Nispen, DNV KEMA's Chief Operating Officer, Americas Division, **said in the press release**. "Traditionally, the large non-residential market drives competitive sales. Now it appears that a growing number of retailers are beginning to focus on the mass market, a market many tended to ignore in the past."

DNV KEMA found competition for smaller customers intensified last year in Illinois, Ohio, and Pennsylvania. Significant residential and small commercial switching to competitive retailers also took place in Pennsylvania, Maine, and New Hampshire in the past 12 months.

The report noted that voters in more than 300 Illinois communities approved municipal aggregation programs last year, which allowed municipal officials to aggregate customers for competitively offered electricity supply offerings. The Illinois Citizens Utility Board recently touted up to $218 million in customer savings thanks to competition in Illinois, much of which was driven by municipal aggregation.

DNV KEMA projected a 6.6% compound annual growth rate in the total U.S. competitive market over the next two years. In 2012, total competitive sales represented 56% of the eligible market, and 20% of all U.S. power sales, the report found.

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Joel Malina | February 22, 2013

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Attachment 10

Pennsylvania electricity market surpasses 2 million shopping customers

Regulators with the Pennsylvania Public Utility Commission (PUC) met at a furniture retail outlet outside of Harrisburg this week, not to issue orders, but to highlight the Keystone State reaching the significant milestone of **more than 2 million electricity customers** choosing to purchase from a competitive supplier.

The furniture store was emblematic of the 2 million homeowners and employers saving money in Pennsylvania's robustly competitive electricity market. But not just jobs-producing businesses are benefiting from the state's competitive retail power market. Nearly 1.7 million of the state's residential customers are purchasing from competitive suppliers, who provide about 35 percent of the residential electricity supply sold in Pennsylvania.

"Consumers are now getting a taste of what they've enjoyed for years with their cell phone, with their cable and their internet providers. Pennsylvania is emerging into one of the most robust markets in America," noted PUC Chairman Robert Powelson.

Powelson and the other commissioners were joined by Doug Wolf, president of Wolf Furniture, which hosted the event at its Mechanicsburg, Pa., store; along with Tom Schneider, Manager of Energy and Operational Efficiencies, North Penn School District; and Ron Cerniglia, governmental & regulatory affairs director with Pittsburgh-based competitive retail energy supplier Direct Energy Services, LLC, who spoke on behalf of the Retail Energy Supply Association (RESA).

Being able to shop for competitively priced electricity provides "budgeting certainty," said Wolf, who also spoke on behalf of the Pennsylvania Retailers' Association. "With so many other business costs being volatile, it's really nice to have an overhead item like your energy usage to be predictable."

"Since we've started to purchase electricity competitively we've reduced our costs by 12% off the utility benchmark. This savings yielded approximately $150,000 a year," said the North Penn school district's Schneider. "These savings, coupled with other energy-related efforts, have yielded a 2011-2012 cost avoidance in excess of $900,000, which have been extremely helpful in preserving instructional programs during the prolonged recession."

RESA's Cerniglia emphasized the benefits of competition beyond cost savings, such jobs creation and investment, and innovative products and services. "Our innovative products and services . . . are designed to meet our customers' needs, rather than a one-size-fits-all approach, as had been the case prior to opening up the competitive market."

"Two million Pennsylvania homeowners and employers have realized that beyond savings per kilowatt-hour, they have electric suppliers competing through innovative product offerings such as free power days, frequent flier miles and help with energy efficiency improvements that further reduce their costs," said Commissioner Pamela Witmer.

The growth in competitive choice in Pennsylvania has been dramatic. When the last of the rate caps inhibiting robust competition expired in 2010, fewer than 340,000 customers were purchasing from a competitive supplier. To exceed 2 million shopping customers just three years later represents exponential growth.

RESA's Cerniglia noted that competitive suppliers provide nearly 60% of all electricity used in Pennsylvania, and the state has more suppliers active in its market than any other state in the country. Nearly 90% of industrial energy usage and 66% of commercial electricity usage is provided by competitive suppliers, Cerniglia noted, citing PUC statistics updated weekly.

But while 2 million is an important milestone, it is a minority of Pennsylvania's 5.6 million electricity customers. The PUC recognizes that its robust retail electricity market represents just the beginning, and it is committed to undertaking further reforms in the electricity sector to promote greater competition.

The agency is expected to unveil this week the conclusions of a regulatory proceeding that PUC Vice Chairman John Coleman described as "intended to ensure the state's regulatory framework is one that encourages a market where consumers have continued choices for electric supply."

"More work lies ahead of us to continue this momentum," said Chairman Powelson. "I am anxious to work on additional steps that will help more consumers and small business owners realize potential cost savings and more innovative products," said Commissioner Witmer.

The COMPETE Coalition and its more than 700 members salute the Pennsylvania PUC for its leadership in bringing the benefits of competition to the state's electricity consumers and economy. With policy direction and support from Gov. Tom Corbett and state lawmakers, Pennsylvania's market is among the top three in the country, according to the **Annual Baseline**

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Assessment of Choice in Canada and the United States (ABACCUS), an annual assessment of competitive retail electricity choice programs in North America.

ABACCUS cited Pennsylvania among just three states offering "useful best practices for other states" to consider in bringing customer choice in electricity to consumers. With the further market enhancements to be announced soon by the commission, Pennsylvania will maintain its leadership in customer choice, and continue to secure economic benefits for the state's consumers and its economy.

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Joel Malina | February 13, 2013

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Attachment 11

nrg | GenOn

NEWS RELEASE

FOR IMMEDIATE RELEASE

NRG and GenOn to Merge; Creating Largest Competitive Power Generation Company in the United States

—Enough Capacity to Power 40 Million American Homes—

Strategic Highlights:

- 47,000 MW (net) of combined capacity, with scale across merit order in three core regions
- $300 million of annual free cash flow (FCF) benefits projected in first full year of operations (2014), including $200 million in annual EBITDA enhancements resulting from cost and operational efficiency synergies
- Transaction substantially accretive to EBITDA and FCF in 2014

Financial Updates:

- NRG pre-announces preliminary financial results (standalone) of approximately $530 million in adjusted EBITDA for the second quarter 2012 and $830 million in adjusted EBITDA for the first half 2012
- NRG reaffirms full-year (standalone) guidance range for 2012 of $1,825-$2,000 million adjusted EBITDA and $800-$1,000 million FCF before growth investment
- GenOn raises full-year (standalone) guidance for 2012 adjusted EBITDA from $446 to $467 million

PRINCETON, NJ and HOUSTON, TX; July 22, 2012— NRG Energy, Inc. (NYSE: NRG) and GenOn Energy, Inc. (NYSE: GEN) today announced they have signed a definitive agreement to combine the two companies in a stock-for-stock tax-free transaction, creating the largest competitive generator in the United States with a diverse fleet of approximately 47,000 megawatts (MW) with asset concentrations in the East, Gulf Coast and West and a combined enterprise value of $18 billion.

"This combination ushers in a new era of scale, scope, and market and fuel diversification in the competitive power industry," said NRG President and CEO David Crane, who will continue his present positions with the combined company. "The greater depth and breadth gained through the combination with GenOn will put NRG in a uniquely strong position to fulfill the needs of American energy consumers in the 21st century."

The transaction will enhance annual combined company EBITDA by $200 million by 2014 by realizing cost and operational efficiency synergies. In addition, the transaction will enable the combined company to reduce its interest and liquidity costs, and realize other balance sheet efficiencies, in aggregate, of $100 million per year. As a result, total recurring FCF benefits generated by this transaction will be approximately $300 million per year.

"This combination will deliver immediate value to the shareholders of both companies who will benefit from the combined company's merger synergies, balance sheet efficiencies, increased scale and additional geographic diversity," said GenOn Chairman and CEO, Edward R. Muller, who will join the NRG Board of Directors as Vice Chairman. "NRG and GenOn are a great fit geographically and operationally and we look forward to working together to capture efficiencies from the scale associated with the transaction to deliver enhanced value to our investors."

Strategic & Financial Benefits

- **Diversification and scale**
  The combined company, which will retain the name NRG Energy, will become the largest competitive power generation company in America with approximately 47,000 MW of fossil fuel, nuclear, solar and wind capacity across the merit order, situated almost entirely in the three premier competitive energy markets in the U.S. The combined fleet generates more than 104 terawatt-hours (TWh) of electricity annually.

- **Expected Synergies**
  Transaction benefits will result in at least $200 million per year in incremental EBITDA and, combined with $100 million of balance sheet efficiencies, will result in at least $300 million of additional FCF by 2014, the first full year of combined operations. The $200 million per year breaks down into $175 million per year in cost synergies, principally resulting from reduced G&A expenses, and $25 million per year of operational efficiency synergies under NRG's *FOR*NRG program. In addition, as a result of interest savings and reduced liquidity and collateral requirements, the combined company will realize an additional $100 million in reduced interest expense and collateral benefits. The transaction costs and total cash "cost to achieve" the synergies and other cash flow benefits will primarily be incurred during 2013 and are estimated at approximately $200 million.

- **Immediately and substantially accretive**
  The transaction will be immediately accretive on an EBITDA basis and substantially accretive in 2014, the first full year of operation, to both EBITDA and FCF before growth investments.

- **Enables expanded wholesale-retail model**
  An expanded core generation fleet will enable the combined company to duplicate in multiple core markets (principally in the East) NRG's successful integrated wholesale-retail business model in ERCOT—the best business model across the price cycle, in an industry that is subject to commodity price volatility.

- **Dividend**
  This transaction will reinforce the ability to pay the 9 cents per share quarterly dividend (36 cents per share on an annual basis) previously announced by NRG for the benefit of both companies' shareholders.

- **Balance sheet and credit metric enhancing**
  Balance sheets efficiencies will permit the combined company to reduce indebtedness by at least $1 billion and enhancements to corporate EBITDA and funds from operations (FFO) significantly improve key credit metrics, including:

	2014 NRG Standalone(1)	2014 NRG Pro Forma (1)
Corporate Debt/Corporate EBITDA	4.6x	4.1x
Corporate FFO/Corporate Debt	13.9%	16.4%

(1) NRG metrics are based on midpoint of guidance and pro forma metrics reflects impact of transaction benefits.

- **Cleaner energy**
  The combined company will continue the work of NRG and GenOn in reducing emissions from their existing conventional fleets. NRG and GenOn combined have invested over $3 billion since 2000 to reduce emissions. This investment has helped NRG reduce SO_2 emissions by 56% and NOx emissions by 64% below 2000 levels and GenOn reduce SO_2 emissions by 90% and NOx emissions by 78% below 1990 levels.

  In addition, the combined company will continue to grow NRG's industry-leading portfolio of solar generating facilities, its eVgo electric vehicle charging network and its other clean energy products and services. In addition, all previously announced plant retirements and deactivations will be completed on schedule.

Financial Terms

GenOn shareholders will receive 0.1216 of a share of NRG common stock in exchange for each GenOn share of common stock. Based on NRG's and GenOn's closing share prices on July 20, the transaction represents a 20.6% premium to GenOn's shareholders.

Following completion of the transaction, NRG shareholders will own 71% of the combined company and GenOn shareholders will own 29%.

Financial Summary

NRG is also announcing preliminary forward pro forma financial guidance for the combined company for 2013 and 2014. This includes:

	2013	2014
Adjusted EBITDA	$2,535-$2,735 million	$2,630-$2,830 million
Free Cash Flow *before investments	$825-$1,025 million	$845-$1,045 million

The above pro forma financial guidance includes updated guidance for GenOn as follows:

- 2013 adjusted EBITDA guidance raised from $669 million to $687 million
- 2014 adjusted EBITDA guidance provided of $730 million

Additionally, GenOn announced today that it is raising its full year guidance for 2012 adjusted EBITDA from $446 to $467 million.

Board Structure, Management and Headquarters

After closing, the Board of Directors will have 16 members with 12 members from the NRG Board and four joining from the GenOn Board. Howard Cosgrove will remain Chairman of the NRG Board and GenOn Chairman and CEO Edward R. Muller will join the NRG Board as Vice Chairman.

In addition to David Crane continuing to serve as Director, President and CEO, Kirk Andrews will remain as Chief Financial Officer and Mauricio Gutierrez will serve as Chief Operating Officer of the combined company. Anne Cleary of GenOn will become the Chief Integration Officer of NRG at closing.

John Ragan and Lee Davis, both currently of NRG, will act as Regional Presidents of the Gulf Coast and East regions, respectively, and John Chillemi of GenOn will become Regional President of the West region, at which time Tom Doyle will focus his efforts as President of NRG Solar.

The combined company will be dual headquartered, with financial and commercial headquarters in Princeton and operational headquarters in Houston.

Update to NRG Results

NRG is also pre-announcing preliminary results for its second quarter 2012. For NRG alone, adjusted EBITDA will be approximately $530 million for the second quarter of 2012 and approximately $830 million in the first half of 2012. NRG also is reaffirming 2012 guidance of $1,825-$2,000 million of adjusted EBITDA and $800-$1,000 million of FCF before growth investment.

Approvals and Time to Close

NRG and GenOn expect to close the merger by the first quarter of 2013. The transaction is subject to customary closing conditions and regulatory approvals, including approval by shareholders of both companies, the Federal Energy Regulatory Commission (FERC), the New York Public Service Commission and the Public Utility Commission of Texas. The companies will also submit notice of the merger to the California Public Utilities Commission and the U.S. Nuclear Regulatory Commission as well as pre-merger notification to the U.S. Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Act. Due to the complementary nature of the two generation portfolios, the merger is not expected to result in any market power issues.

NRG's financial advisors were Credit Suisse and Morgan Stanley and J.P. Morgan acted as GenOn's financial advisor.

Financial Community Presentation

A live webcast regarding this announcement will be held at 9:00am Eastern on Monday, July 23 and be hosted by David Crane, NRG President and CEO and Edward R. Muller, GenOn Chairman and CEO. Investors, media and others may access this event by logging on to either NRG's website at http://www.nrgenergy.com and clicking on "Investors" or GenOn's website, www.genon.com and clicking on Investor Relations. The webcast will be archived on each site for those unable to listen in real time.

Press Conference

A telephonic press conference regarding this announcement will be held at 12:00pm ET/9am PT on Monday, July 23, and will be co-hosted by David Crane, NRG President and CEO, and Edward R. Muller, GenOn Chairman and CEO. Members of the media can access this call by dialing 866.314.5232. The passcode is: 86974439.

About NRG

NRG is at the forefront of changing how people think about and use energy. A Fortune 500 company, NRG is a pioneer in developing cleaner and smarter energy choices for our customers: whether as one of the largest solar power developers in the country, or by building the first privately funded electric vehicle charging infrastructure or by giving customers the latest smart energy solutions to better manage their energy use. Our diverse power generating facilities can support more than 20 million homes and our retail electricity providers – Reliant, Green Mountain Energy Company and Energy Plus – serve more than two million customers. More information is available at www.nrgenergy.com.

About GenOn

GenOn is one of the largest competitive generators of wholesale electricity in the United States. With power generation facilities located in key regions of the country and a generation portfolio of approximately 22,700 megawatts, GenOn is helping meet the nation's electricity needs. GenOn's portfolio of power generation facilities includes baseload, intermediate and peaking units using coal, natural gas and oil to generate electricity. GenOn has experienced leadership, dedicated team members, financial strength and a solid commitment to safety, the environment, operational excellence and the communities in which it operates. GenOn routinely posts all important information on its web site at www.genon.com.

Forward Looking Statements

In addition to historical information, the information presented in this communication includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. These statements involve estimates, expectations, projections, goals, assumptions, known and unknown risks and uncertainties and can typically be identified by terminology such as "may," "will," "should," "could," "objective," "projection," "forecast," "goal," "guidance," "outlook," "expect," "intend," "seek," "plan," "think," "anticipate," "estimate," "predict," "target," "potential" or "continue" or the negative of these terms or other comparable terminology. Such forward-looking statements include, but are not limited to, statements about the anticipated benefits of the proposed transaction between NRG and GenOn, each party's and the combined company's future revenues, income, indebtedness, capital structure, plans, expectations, objectives, projected financial performance and/or business results and other future events, each party's views of economic and market conditions, and the expected timing of the completion of the proposed transaction.

Forward-looking statements are not a guarantee of future performance and actual events or results may differ materially from any forward-looking statement as result of various risks and uncertainties, including, but not limited to, those relating to: the ability to satisfy the conditions to the proposed transaction between NRG and GenOn, the ability to successfully complete the proposed transaction (including any financing arrangements in connection therewith) in accordance with its terms and in accordance with expected schedule, the ability to obtain stockholder, antitrust, regulatory or other approvals for the proposed transaction, or an inability to obtain them on the terms proposed or on the anticipated schedule, diversion of management attention on transaction-related issues, impact of the transaction on relationships with customers, suppliers and employees, the ability to finance the combined business post-closing and the terms on which such financing may be available, the financial performance of the combined company following completion of the proposed transaction, the ability to successfully integrate the businesses of NRG and GenOn, the ability to realize anticipated benefits of the proposed transaction (including expected cost savings and other synergies) or the risk that anticipated benefits may take longer to realize than expected, legislative, regulatory and/or market developments, the outcome of pending or threatened lawsuits, regulatory or tax proceedings or investigations, the effects of competition or regulatory intervention, financial and economic market conditions, access to capital, the timing and extent of changes in law and regulation (including environmental), commodity prices, prevailing demand and market prices for electricity, capacity, fuel and emissions allowances, weather conditions, operational constraints or outages, fuel supply or transmission issues, hedging ineffectiveness.

Additional information concerning other risk factors is contained in NRG's and GenOn's most recently filed Annual Reports on Form 10-K, subsequent Quarterly Reports on Form 10-Q, recent Current Reports on Form 8-K, and other SEC filings.

Many of these risks, uncertainties and assumptions are beyond NRG's or GenOn's ability to control or predict. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Furthermore, forward-looking statements speak only as of the date they are made, and neither NRG nor GenOn undertakes any obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this communication. All subsequent written and oral forward-looking statements concerning NRG, GenOn, the proposed transaction, the combined company or other matters and attributable to NRG or GenOn or any person acting on their behalf are expressly qualified in their entirety by the cautionary statements above.

Additional Information and Where To Find It

This communication does not constitute an offer to sell or the solicitation of an offer to buy any securities or a solicitation of any vote or approval, nor shall there be any sale of securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction. The proposed business combination transaction between NRG and GenOn will be submitted to the respective stockholders of NRG and GenOn for their consideration. NRG will file with the Securities and Exchange Commission ("SEC") a registration statement on Form S-4 that will include a joint proxy statement of NRG and GenOn that also constitutes a prospectus of NRG. NRG and GenOn will mail the joint proxy statement/prospectus to their respective stockholders. NRG and GenOn also plan to file other documents with the SEC regarding the proposed transaction. This communication is not a substitute for any prospectus, proxy statement or any other document which NRG or GenOn may file with the SEC in connection with the proposed transaction. INVESTORS AND SECURITY HOLDERS OF GENON AND NRG ARE URGED TO READ THE JOINT PROXY STATEMENT/PROSPECTUS AND ANY OTHER RELEVANT DOCUMENTS THAT WILL BE FILED WITH THE SEC CAREFULLY AND IN THEIR ENTIRETY WHEN THEY BECOME AVAILABLE BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT THE PROPOSED TRANSACTION. Investors and stockholders will be able to obtain free copies of the joint proxy statement/prospectus and other documents containing important information about NRG and GenOn, once such documents are filed with the SEC, through the website maintained by the SEC at www.sec.gov. NRG and GenOn make available free of charge at www.nrgenergy.com and www.genon.com, respectively (in the "Investor Relations" section), copies of materials they file with, or furnish to, the SEC.

Participants in The Merger Solicitation

NRG, GenOn, and certain of their respective directors and executive officers may be deemed to be participants in the solicitation of proxies from the stockholders of GenOn and NRG in connection with the proposed transaction. Information about the directors and executive officers of NRG is set forth in its proxy statement for its 2012 annual meeting of stockholders, which was filed with the SEC on March 12, 2012. Information about the directors and executive officers of GenOn is set forth in its proxy statement for its 2012 annual meeting of stockholders, which was filed with the SEC on March 30, 2012. These documents can be obtained free of charge from the sources indicated above. Other information regarding the participants in the proxy solicitation and a description of their direct and indirect interests, by security holdings or otherwise, will be contained in the joint proxy statement/prospectus and other relevant materials to be filed with the SEC when they become available.

# # #

NRG

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Attachment 12

An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States

Lawrence R. Greenfield
Associate General Counsel – Energy Markets 1
Office of the General Counsel
Federal Energy Regulatory Commission

December 2010

Note: The views expressed herein are the author's, and do not necessarily reflect the views of the Commission, individual Commissioners, Commission staff or individual Commission staff members.

Part I:

The Federal Energy Regulatory Commission and Federal Regulation of Public Utilities

What is FERC?

- A Federal Agency
- An Independent Agency
  - Independent from political party influence: because no more than 3 Commissioners from one party
  - Independent from President's/Congress' influence: because FERC decisions are reviewed by a court
  - Independent from parties' influence: because private discussions in contested case-specific proceedings are prohibited by FERC's "ex parte" regulation (18 CFR 385.2201)

Who are the Commissioners?

- Nominated by the President and confirmed by the Senate
- Serve staggered 5-year terms
- No more than 3 Commissioners may be from the same political party

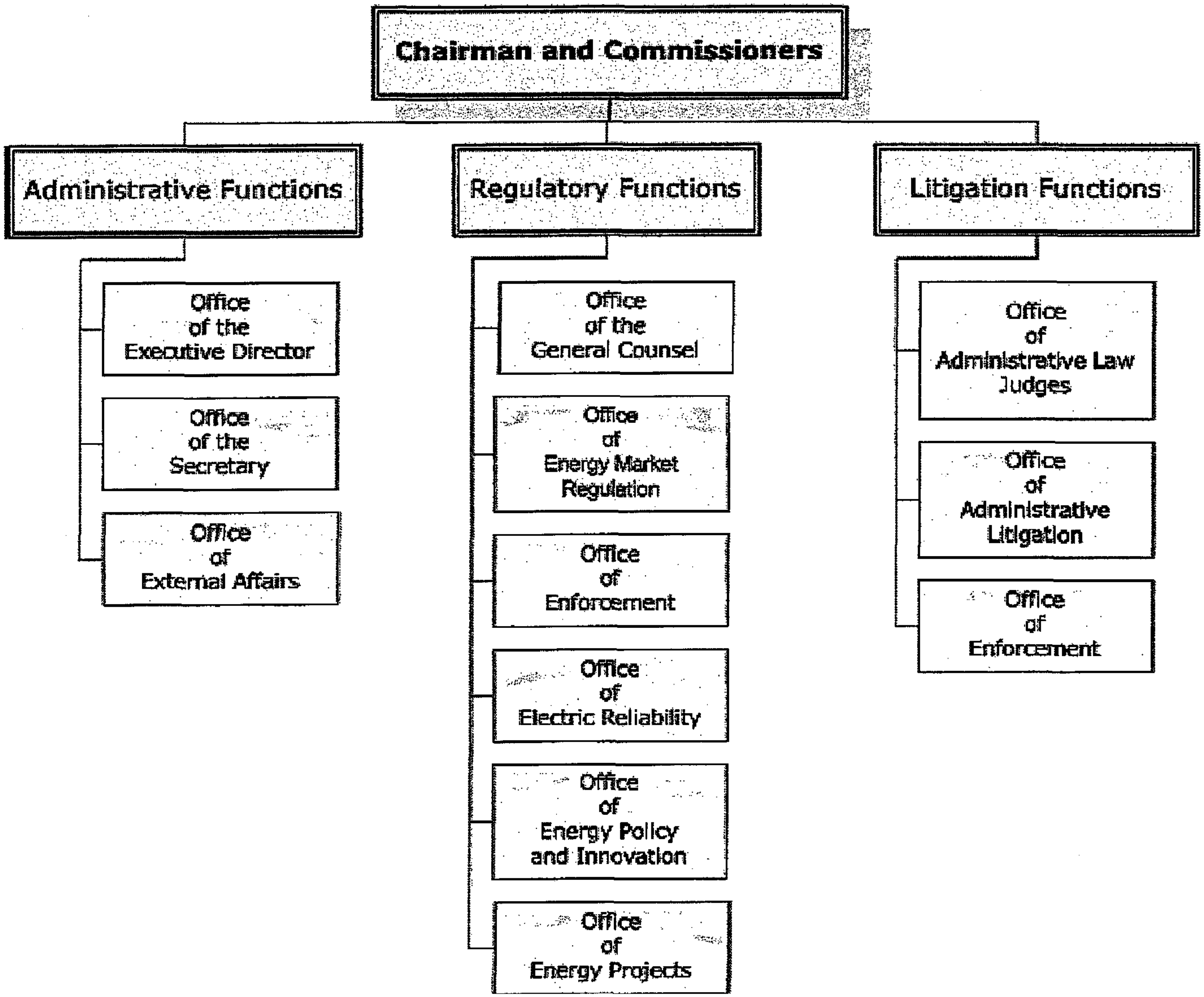
How is FERC organized – Part 1?

- *Commissioners*– 5 Commissioners; each has 1 vote (FERC action requires a majority vote)
- *Chairman* – has 1 vote, but the Chairman is FERC's administrative head

- *Staff* – for the current fiscal year, FERC has requested funding for approximately 1540 employees - including attorneys, accountants, engineers, economists, rate analysts, etc.

- *Budget* – for the current fiscal year, FERC has requested a budget of $315.6 million:
  - Budget process involves a recommendation by the President and authorization by Congress (at present, FERC is operating under a so-called "continuing resolution")
  - But funds equal to the budget are reimbursed through: filing fees for individual filings assessed to the filing entity, and annual charges assessed generally to the regulated industries - so that the agency has a "0" effect on the government's overall budget

How is FERC organized – Part 2?



How is FERC organized – Part 3?

- **Office/Organization Descriptions (taken from FERC's website) –**
- Office of Administrative Law Judges: Resolves contested cases as directed by the Commission effectively, efficiently and expeditiously, either through impartial hearing and decision or through negotiated settlement, ensuring that the rights of all parties are preserved.
- Office of Administrative Litigation: Litigates or otherwise resolves cases set for hearing. Represent the public interest and seek to litigate or settle cases in a timely, efficient and equitable manner while ensuring the outcomes are consistent with Commission policy.
- Office of Electric Reliability: Oversees the development and review of mandatory reliability and security standards. Ensures compliance with the approved mandatory standards by the users, owners, and operators of the bulk power system.
- Office of Energy Market Regulation: Deals with matters involving markets, tariffs and rates relating to electric, natural gas, and oil pipeline facilities and services.
- Office of Energy Policy and Innovation: Issues, coordinates, and develops proposed policy reforms to address emerging issues affecting wholesale and interstate energy markets, including such areas as climate change, the integration of renewable resources, and the deployment of demand response and distributed resources, smart grid and other advanced technologies.
- Office of Energy Projects: Fosters economic and environmental benefits for the nation through the approval and oversight of hydroelectric and natural gas pipeline energy projects that are in the public interest.
- Office of Enforcement: Serves the public interest by guiding the evolution and operation of energy markets to ensure effective regulation and protecting customers through understanding markets and their regulation, timely identifying and remedying market problems, assuring compliance with rules and regulations, and detecting and crafting penalties to address market manipulation.
- Office of External Affairs: Responsible for all external communications with the public and media for the Commission.
- Office of the Executive Director: Provides administrative support services to the Commission including human resources, procurement, information technology, organizational management, financial, logistics and others.
- Office of the General Counsel: Provides legal services to the Commission. OGC represents the Commission before the courts and Congress and is responsible for the legal phases of the Commission's activities.
- Office of the Secretary: Serves as the official focal point through which all filings are made for all proceedings before the Commission, notices of proceedings are given, and from which all official actions are issued by the Commission. The Secretary promulgates and publishes all orders, rules, and regulations of the Commission and prescribes the issuance date for these unless such date is prescribed by the Commission.

FERC's History

- Federal Power Commission:
  - Federal Water Power Act of 1920
  - Public Utilities Act of 1935: Title I - The Public Utility Holding Company Act of 1935; Title II - The Federal Power Act
  - Natural Gas Act of 1938
- Federal Energy Regulatory Commission:
  - Department of Energy Organization Act of 1977

What does FERC regulate?

- Electric transmission and wholesale sales rates and services – Principally under Parts II and III of the Federal Power Act
- Hydroelectric dam licensing and safety – Principally under Part I of the Federal Power Act
- Natural gas pipeline transportation rates and services – Principally under the Natural Gas Act
- Oil pipeline transportation rates and services – Principally under the Interstate Commerce Act
- Bear in mind, however, that FERC is a creature of statute, and can only do what a statute allows it do. *California Independent System Operator Corporation v. FERC*, 372 F.3d 395, 398-99 (D.C. Cir. 2004).

What is within FERC's public utility-related statutory authority (i.e., FPA Parts II and III)?

- What does FERC regulate under Parts II and III of the Federal Power Act (FPA):
  - FERC's "bread-and-butter" <> the regulation of public utility transmission and sales for resale:
    - Transmission of electric energy in interstate commerce by public utilities, i.e., the rates, terms & conditions of interstate electric transmission by public utilities – FPA 201, 205, 206 (16 USC 824, 824d, 824e)
    - Sales of electric energy at wholesale in interstate commerce by public utilities, i.e., the rates, terms & conditions of wholesale electric sales by public utilities – FPA 201, 205, 206 (16 USC 824, 824d, 824e)
    - That is, FERC has *exclusive* jurisdiction over the "transmission of electric energy in interstate commerce," and over the "sale of electric energy at wholesale in interstate commerce," and over "all facilities for such transmission or sale of electric energy." 16 USC 824(b); *e.g., Pennsylvania Power & Light Company*, 23 FERC ¶ 61,006 at 61,018, *reh'g denied*, 23 FERC ¶ 61,325 (1983); *Southern Company Services, Inc.*, 37 FERC ¶ 61,256 at 61,652 (1986); *Florida Power & Light Company*, 40 FERC ¶ 61,045 at 61,120-21, *reh'g denied*, 41 FERC ¶ 61,153 at 61,382 (1987); *Houlton Water Company v. Maine Public Service Company*, 60 FERC ¶ 61,141 at 61,515 (1992); *Northern Indiana Public Service Company*, 66 FERC ¶ 61,213 at 61,488 (1994); *Connecticut Light and Power Company*, 70 FERC ¶ 61,012 at 61,030, *reconsid. denied*, 71 FERC ¶ 61,035 (1995); *Central Vermont Public Service Corporation*, 84 FERC ¶ 61,194 at 61,973-75 (1998); *Progress Energy, Inc.*, 97 FERC ¶ 61,141 at 61,628 (2001); *Armstrong Energy Limited Partnership, LLLP*, 99 FERC ¶ 61,024 at 61,104 (2002); *Niagara Mohawk Power Corporation*, 100 FERC ¶ 61,019 at P 17 (2002); *Barton Village, Inc. v. Citizens Utilities Company*, 100 FERC ¶ 61,244 at P 12 (2002); *Virginia Electric and Power Company*, 103 FERC ¶ 61,109 at P 6 (2003); *Southern California Edison Company*, 106 FERC ¶ 61,183 at P 14, 19 (2004); *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,337 at P 14 & n.17 (2004); *Entergy Services, Inc.*, 120 FERC ¶ 61,020 at P 28 (2007); *Aquila Merchant Services, Inc.*, 125 FERC ¶ 61,175 at P 17 (2008).
  - Corporate activities and transactions by public utilities – mergers, securities issuances, interlocking directorates, etc. – FPA 203, 204, 305(b) (16 USC 824b, 824c, 825d(b))
  - Accounting by public utilities – FPA 301 (16 USC 825)
  - Reliability – FPA 215 (16 USC 824o)

"Public Utility" status is the key to understanding many FPA Parts II and III jurisdictional questions

- Most sections found in Parts II and III of the Federal Power Act provide for Commission authority over the actions of a "public utility," and a "public utility" is defined by the statute as "any person who owns or operates facilities subject to the jurisdiction of the Commission," i.e., "any person who owns or operates" facilities for "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce" (16 USC 824(e))
- "Public utilities" (16 USC 824(e)) are not the same as "electric utilities" (16 USC 796(22)) and are not the same as "transmitting utilities (16 USC 796(23))

What is <u>not</u> within FERC's public utility-related statutory authority (i.e., FPA Parts II and III)?

- "Local" distribution of electric energy, and the rates, terms and conditions of such distribution
- Sales of electric energy to end users (i.e., sales at retail), and the rates, terms and conditions of such sales
- Siting and construction of generation (other than hydroelectric generation, which is subject to FERC jurisdiction under Part I of the FPA) and transmission facilities (with the exception of so-called "backstop" siting authority under FPA 216 (16 USC 824p)) (*E.g.*, *Californians for Renewable Energy Inc. v. California Independent System Operator Corp.*, 117 FERC ¶ 61,072 at P 10 (2006); *PacifiCorp*, 72 FERC ¶ 61,087 at 61,488 & n.3 (1995); *Duke Power Co.*, 43 FERC ¶ 61,001 at 61,003 (1988): *Northeast Maryland Waste Disposal Authority*, 53 FERC ¶ 61,161 at 61,587 (1990), *reh'g denied*, 54 FERC ¶ 61,058 (1991); *Southern Company Services, Inc.*, 22 FERC ¶ 61,047 at 61,084 (1983))
- Environmental matters (with the exception of hydroelectric generation-related environmental matters, which are subject to FERC jurisdiction under Part I of the FPA) (*E.g.*, *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,117 at 61,448 (2001); *PSI Energy, Inc.*, 56 FERC ¶ 61,237 at 61,911 & n.27 (1991); *Duke Power Co.*, 43 FERC ¶ 61,001 at 61,003 (1988); *Monongahela Power Co.*, 39 FERC ¶ 61,350 at 62,096, *reh'g denied*, 40 FERC ¶ 61,256 (1987))
  - But rate recovery of environmental costs, as with rate recovery of any other cost, is subject to FERC review
- Safety matters (with the exception of hydroelectric generation-related safety matters, which are subject to FERC jurisdiction under Part I of the FPA)
- United States government and its agencies and instrumentalities, and States and their agencies and instrumentalities (including municipalities) - with certain limited exceptions, e.g., FPA 206(e), 222 (16 USC 824e(e), 824w)
- RUS-financed cooperatives and large cooperatives
- *Inter*state v. *Intra*state: Alaska and Hawaii (where, given their electrical isolation, there is no *inter*state . . .); Electric Reliability Council of Texas (for the same reason, but with certain limited exceptions). But, the fact that sellers and buyers are located within a single state, and that there may be lines between them located within that same state, does <u>not</u> divest FERC of jurisdiction given the interconnected nature of the electric grid. That is, "interstate commerce" has been interpreted to give the Commission jurisdiction when the transmission system "is interconnected and capable of transmitting [electric] energy across the State boundary, even though the contracting parties and the electrical pathway between them are within one State," <u>i.e.</u>, if the transaction is made over the "interconnected interstate transmission grid." *Florida Power & Light Company*, 29 FERC ¶ 61,140 at 61,291-92 (1984). (*Accord, e.g.*, *Wisconsin Electric Power Company*, 62 FERC ¶ 61,142 at 62,008 n.40 (1993), *reh'g denied*, 66 FERC ¶ 61,096 (1994); *People's Electric Cooperative*, 84 FERC ¶ 61,229 at 62,108-12, 62,113-14, 62,130-31 (1998), *reh'g denied*, 93 FERC ¶ 61,218 at 61,727, 61,730-31 (2000); *Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,966-69 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), . . ., *aff'd in relevant part*, 225 F.3d 667, 690-95 (D.C. Cir. 2000), *aff'd in relevant part*, 535 U.S.1 (2002))
- One further thought to bear in mind: sales v. purchases – FPA 205 and 206 (16 USC 824d, 824e) are written from the perspective of the seller; that is, FERC has the exclusive authority to review the rates, terms and conditions of "sales" but <u>not</u> of "purchases" ("purchases" are the province of state commissions)

NGO Participation in FERC Proceedings (Part 1)

- Rulemaking proceedings
  - Participation by filing comments by FERC-specified comment date
  - FERC's "ex parte" regulations do not apply in rulemaking proceedings (18 CFR 385.2201(a), (b), (c)(1)(ii))
- Case-specific proceedings
  - Participation by intervening (18 CFR 385.214)
    - Intervention is necessary for "party" status, and "party" status is necessary, not only in order to receive copies of other parties' pleadings and FERC's orders, but also to participate in the proceeding – including the right to ask FERC to grant rehearing/reconsideration of its decision and the right to seek subsequent judicial review (16 USC 825l)
  - Participation by protesting (18 CFR 385.211)
  - Participation by filing a complaint (18 CFR 385.206)
  - FERC's "ex parte" regulations do apply in case-specific, contested proceedings (18 CFR 385.2201(a), (b), (c)(1)(i))

NGO Participation in FERC Proceedings (Part 2)

- "Party" status in utility-filed FPA 205 proceedings
  - Intervention (requirements: 18 CFR 385.214)
    - Intervention is necessary to be a "party" (18 CFR 385.102(c)(3))
  - Intervenor (pursuant to 18 CFR 385.214) *versus* Protestor (pursuant to 18 CFR 385.211)
    - Intervention does <u>not</u> make one a protestor, and a protest does <u>not</u> make one an intervenor (and thus does <u>not</u> make one a party)
      - The filing of an intervention alone, without a protest, does not make a proceeding "contested." *Midwest Power Systems, Inc.*, 69 FERC ¶ 61,025 at 61,104 (1994)
      - The filing of a protest alone, without an intervention, does not make an entity a party. *Pacific Gas & Electric Company*, 111 FERC ¶ 61,156 at P 13 (2005)
- "Party" Status in complaint/FERC initiated FPA 206 proceedings
  - Intervention (requirements: 18 CFR 385.214)
    - Intervention is necessary to be a "party" (18 CFR 385.102(c)(3))
  - Intervenor (pursuant to 18 CFR 385.214) *versus* Protestor (pursuant to 18 CFR 385.211)
    - Intervention does <u>not</u> make one a protestor, and a protest does <u>not</u> make one an intervenor (and thus does <u>not</u> make one a party)
      - The filing of an intervention alone, without a protest, does not make a proceeding "contested." *Midwest Power Systems, Inc.*, 69 FERC ¶ 61,025 at 61,104 (1994)
      - The filing of a protest alone, without an intervention, does not make an entity a party. *Pacific Gas & Electric Company*, 111 FERC ¶ 61,156 at P 13 (2005)
  - Complainant (pursuant to 18 CFR 385.206)
    - Complainant is automatically a party (18 CFR 385.102(c)(1))
- *Timely* intervention is important
  - Timely, unopposed interventions are automatically granted (18 CFR 385.214(c)(1))
  - Untimely, i.e., late, interventions require an affirmative grant of party status (18 CFR 385.214(c)(1), 385.214(d))
    - <u>But</u>, in an FPA 205 proceeding, once FERC has issued an order, FERC policy is generally to deny late interventions that are coupled with a request for rehearing/reconsideration of the order (*E.g.*, *Pacific Gas & Electric Company*, 100 FERC ¶ 61,097 at P 5 (2002); *American Electric Power Service Corporation*, 111 FERC ¶ 61,372 at P 16-17 (2005); *California Independent System Operator Corporation*, 112 FERC ¶ 61,337 at P 3 (2005); *Bridgeport Energy, LLC*, 114 FERC ¶ 61,265 at P 4 (2006)).
    - <u>And</u> FERC rejects the accompanying requests for rehearing/reconsideration, as such requests must be filed by a party (16 USC 825*l*(a); *e.g.*, *American Electric Power Service Corporation*, 111 FERC ¶ 61,372 at P 18 (2005); *California Independent System Operator Corporation*, 112 FERC ¶ 61,337 at P 3 (2005))
    - <u>And</u> filing for reconsideration/rehearing is a necessary prerequisite to seeking judicial review (16 USC 825*l*(b))
  - Separately, opposed interventions also require an affirmative grant of party status, but FERC is generally inclined to grant opposed interventions and so interventions are, in practice, rarely opposed (18 CFR 385.214(c)(1))

Case-specific proceedings: how does FERC protect customers from excessive rates?

- Review of public utility filings asking to establish or change rates (Addressed in Part II below)

- Review of customer/competitor/state commission/attorney general/etc. complaints asking to change rates (Addressed in Part III below)

- Independent Commission review of rates, <u>i.e.</u>, Commission review <u>not</u> initiated by an electric utility filing or a customer/competitor complaint (Addressed in Part III below)

FERC's Website

<u>www.ferc.gov</u>

(within which is "eLibrary" – a public database containing all submissions to FERC and all issuances by FERC in docketed proceedings)

Part II:
Rate Revision Process:
Federal Power Act Section 205

Federal Power Act Section 205
- What Must Be Filed -

- Public utilities must file the rates, terms and conditions for interstate electricity transmission and wholesale electricity sales:
  - Rates, terms and conditions must be filed
  - Rates, terms and conditions must be public
  - But, there are some exceptions to the filing requirement: e.g., individual customer-specific rates, terms and conditions need not be filed if they conform to model *pro forma* agreements that are filed (with individual customer-specific rates reported in quarterly reports known as "EQRs"), or if they are market-based power sales rates (with individual customer-specific rates reported in quarterly reports known as "EQRs")

Federal Power Act Section 205
- When Must They Be Filed -

- Absent waiver, public utilities must file at least 60 days before any proposed rate, term or condition is to become effective – i.e., absent waiver, utilities must give at least 60 days' prior notice
- Waiver can be granted to allow proposed rates, terms or conditions to become effective on less than 60 days' prior notice
- If public utilities do not file timely, and waiver is not granted, they must provide "time value" refunds, i.e., "interest" refunds, to their customers for the period of time the rates were collected without authorization

Federal Power Act Section 205
- When Must Responses Be Filed -

- Public notice of a filing is issued, providing a time for responses
  - For typical filings, unless a notice is issued providing otherwise, **21 days** is normally allowed for responses (bear in mind that FERC often has a statutory 60-day action date – so FERC's ability to grant extensions is limited) (18 CFR 35.8)
  - Timely response is essential to preserving your rights, as discussed above
  - Note: For those of you interested in Natural Gas Act section 4 filings (the counterpart to Federal Power Act section 205 filings), for typical filings, unless a notice is issued providing otherwise, 12 days is normally allowed for responses (bear in mind that FERC often has a statutory 30-day action date – so FERC's ability to grant extensions is limited) (18 CFR 154.210(a))

Federal Power Act Section 205
- What Can FERC Do -

- FERC can find the filing deficient, i.e., incomplete
- FERC can accept the rates, terms and conditions, i.e., rule "on the paper"
- FERC can reject the rates, terms and conditions, i.e., rule "on the paper"
- FERC can "suspend," i.e., defer, the effectiveness of the rates, terms and conditions
  - "Suspension" is for up to 5 months
  - At the end of the "suspension period," the rates, terms and conditions become effective subject to refund unless, by that date, FERC has issued a final order
  - At the end of the case, FERC can order refunds back to the effective date (or provide other remedies) for rates, terms and conditions that are "unjust and unreasonable" or that are "unduly discriminatory or preferential"
- FERC can send the rates, terms and conditions to trial-type, oral hearing or can order settlement judge/alternative dispute resolution procedures
- FERC can choose some combination of the above

Federal Power Act Section 205
- What Standard Does FERC Use –
Part 1

- Rates, terms and conditions *must be* "just and reasonable" and *must be* "not unduly discriminatory or preferential"
- Phrased differently: rates, terms and conditions *cannot be* "unjust or unreasonable" and *cannot be* "unduly discriminatory or preferential"
- The same standard governs both section 205 proceedings, i.e., utility-initiated proceedings, and section 206 proceedings, i.e., complaint/FERC-initiated proceedings

Federal Power Act Section 205
- What Standard Does FERC Use –
Part 2

- What is a "just and reasonable" rate?
  - Cost-justified
  - Market-justified
- What is a "not unduly discriminatory or preferential" rate?
  - Similarly-situated customers must be treated similarly
    - Discrimination without a reason is prohibited:
      - E.g., a difference in rates that is not cost-justified
    - Discrimination with a reason is allowed
      - E.g., a difference in rates that is cost-justified
  - Differences in treatment are <u>not</u> inherently prohibited
- Again, the same standards govern both section 205 proceedings, i.e., utility-initiated proceedings, and section 206 proceedings, i.e., complaint/FERC-initiated proceedings

Part III:
Rate Challenge Process:
Federal Power Act Section 206

Federal Power Act Section 206
- The Basics -

- FERC, either pursuant to a complaint or on its own, (1) may find that an existing rate, term or condition is not just and reasonable or is unduly discriminatory or preferential, and (2) specify a new rate, term or condition that is just and reasonable and not unduly discriminatory or preferential and that is to be thereafter used
- Complaints may be filed by any person – including a customer or a competitor

Federal Power Act Section 206
- Remedies -
Part 1

- FERC remedies in complaint/FERC-initiated proceedings are typically prospective or forward-looking only; that is, from the date of the FERC order (1) finding an existing rate, term or condition is not just and reasonable or is unduly discriminatory or preferential, and (2) specifying a new rate, term or condition that is just and reasonable and is not unduly discriminatory or preferential and that is to be thereafter used

Federal Power Act Section 206
- Remedies -
Part 2

- Exceptions:
  - *Complaint-initiated cases*: 15 month "refund window" – i.e., up to 15 months of refunds are allowed, which can <u>begin</u> as early as the date a complaint is filed or as late as 5 months from the date a complaint is filed
  - *FERC-initiated cases*: 15 month "refund window" – i.e., up to 15 months of refunds are allowed, which can <u>begin</u> as early as FERC publishes a notice that a case has been initiated or as late as 5 months from the date FERC publishes a notice that a case has been initiated

Federal Power Act Section 206
- Remedies -
Part 3

- Additional Exceptions:
  - Violations of "filed rate": refunds and/or disgorgement of profits may be ordered for failure to abide by the "filed rate" in past years/months
  - Formula rates: refunds may be ordered for abuse of formula rates in prior years

Federal Power Act Section 206
- Remedies -
Part 4

- As a result of the Energy Policy Act of 2005, . . .
  - Market manipulation is now prohibited, FPA 222 (16 USC 824w)
  - FERC now has authority to impose penalties up to $1 million per violation per day, FPA 316A (16 USC 825o-1)

Federal Power Act Section 206
- Processing Complaints -
Part 1

- Public notice of a complaint is issued, providing a time for responses
  - For typical complaints, unless a notice is issued providing otherwise, **20 days** is normally allowed for responses (18 CFR 385.206(f))
  - For "fast-track" complaints, 10 days or less may be allowed for responses (18 CFR 385.206(h); *Complaint Procedures*, Order No. 602, FERC Stats. & Regs. 31,071 at 30,766, *order on reh'g*, Order No. 602-A, FERC Stats. & Regs. 31,076, *order on reh'g*, Order No. 602-B, FERC Stats. & Regs. 31,083 (1999))
  - Timely response is essential to preserving your rights, as discussed above
  - Note: For those of you interested in Natural Gas Act section 5 complaints (the counterpart to Federal Power Act section 206 complaints), the same regulations and timeframes apply

Federal Power Act Section 206
- Processing Complaints -
Part 2

- FERC may:
  - Rule summarily, i.e., “on the paper,” on a complaint – granting or denying
  - Institute trial-type, oral hearing procedures to gather more information
  - Institute settlement judge or alternative dispute resolution procedures to promote consensual resolution
  - Adopt some combination of the above

Federal Power Act Section 206 - Processing Complaints - Part 4

- A simplified complaint process may be used if the dispute involves less than US $100,000 and the effect on non-parties will be de minimus
- But, given the nature of FERC's jurisdiction and the parties before FERC, these circumstances are rarely invoked

Part IV:
Some FERC Orders of Interest

Order Nos. 888 and 888-A – Open Access Transmission

- All public utilities that own, control or operate jurisdictional transmission facilities are required to have open access transmission tariffs (18 CFR 35.28(a) & (c)) – the goal was to eliminate undue discrimination/preference
  - That tariff must track the FERC-mandated *pro forma* open access transmission tariff, unless a waiver has been granted
  - Not just third-party customers, but the public utilities themselves must take service pursuant to this tariff
- Non-public utilities may have "reciprocity" open access transmission tariffs (18 CFR 35.28(a) & (e))
  - "Reciprocity" provides a so-called safe harbor, ensuring that the non-public utility is entitled to transmission service from public utilities

Order Nos. 890 and 890-A – Improvements in Open Access Transmission, e.g., Transmission Planning (Part 1)

- Overall, in Order Nos. 890 and 890-A, FERC sought to make improvements to its *pro forma* open access transmission tariff, and better achieve the goal of eliminating undue discrimination/preference
- One principal reform was with respect to transmission planning – with adoption of FERC-mandated coordinated, open and transparent transmission planning
  - Order No. 888 (and 888-A) *pro forma* tariff, in section 28.2, for example, required simply that the transmission provider plan and construct additional transmission facilities so as to be able to serve network customers "on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers." While FERC encouraged joint planning with customers and other utilities, and also regional planning, FERC did not mandate such planning.
  - To better ensure that planning and construction occur in a non-unduly discriminatory manner, Order No. 890 (and 890-A) took a more aggressive approach – mandating coordinated, open and transparent transmission planning on a local and regional level. FERC explained that, in light of a decline in investment relative to load growth resulting in increased congestion and a reduced access to alternative sources of energy, as well as a disincentive to remedy congestion on a non-unduly discriminatory basis, reform of the Order No. 888 (and 888-A) *pro forma* tariff was needed.
  - In Order No. 890-A (at paragraph 181), the Commission explained:

> The Commission identified nine planning principles in Order No. 890 that must be satisfied for a transmission provider's planning process to be considered compliant with that order. These nine planning principles are:
>
> (1) Coordination – the process for consulting with transmission customers and neighboring transmission providers;
>
> (2) Openness – planning meetings must be open to all affected parties;
>
> (3) Transparency – access must be provided to the methodology, criteria, and processes used to develop transmission plans;
>
> (4) Information Exchange – the obligations of and methods for customers to submit data to transmission providers must be described;
>
> (5) Comparability – transmission plans must meet the specific service requests of transmission customers and otherwise treat similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning;
>
> (6) Dispute Resolution – an alternative dispute resolution process to address both procedural and substantive planning issues must be included;
>
> (7) Regional Participation – there must be a process for coordinating with interconnected systems;
>
> (8) Economic Planning Studies – study procedures must be provided for economic upgrades to address congestion or the integration of new resources, both locally and regionally; and
>
> (9) Cost Allocation – a process must be included for allocating costs of new facilities that do not fit under existing rate structures, such as regional projects.

Order Nos. 890, 890-A, and 890-B – Improvements in Open Access Transmission, e.g., Transmission Planning (Part 2)

- The Commission thus adopted a new "Attachment K" to its *pro forma* open access transmission tariff; Order No. 890-B contained the following *pro forma* Attachment K:

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

The process for consulting with customers and neighboring transmission providers;
The notice procedures and anticipated frequency of meetings;
The methodology, criteria, and processes used to develop transmission plans;
The method of disclosure of criteria, assumptions and data underlying transmission system plans;
The obligations of and methods for customers to submit data to the transmission provider;
The dispute resolution process;
The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and
The relevant cost allocation procedures or principles.

Order Nos. 719 and 719-A – Competition in Wholesale Electric Markets (Part 1)

- FERC recognized that reforms were necessary to improve the operation of the organized wholesale electric markets (the markets operated by ISO New England, NYISO, PJM, Midwest ISO, CAISO, and SPP), and thus to improve the competitiveness of those markets.
- Accordingly, in Order No. 719 (and 719-A), FERC adopted improvements in the areas of:
  - Demand response and use of market pricing to elicit demand response during periods of operating reserve shortages
  - Long-term power contracting
  - Market monitoring
  - Responsiveness of the organized wholesale electric markets to their customers and other stakeholders

Order Nos. 719 and 719-A – Competition in Wholesale Electric Markets (Part 2)

- In Order No. 719-A (at paragraphs 2-7 (footnotes deleted; emphasis added)), the Commission delineated the improvements adopted in Order No. 719:

In the area of ***demand response***, the Commission required each RTO and ISO to: (1) accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary services on a basis comparable to other resources; (2) eliminate, during a system emergency, a charge to a buyer that takes less electric energy in the real-time market than it purchased in the day-ahead market; (3) in certain circumstances, permit an aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the organized energy market; and (4) modify their market rules, as necessary, to allow the market-clearing price, during periods of operating reserve shortage, to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

Additionally, the Commission recognized that further reforms may be necessary to eliminate barriers to demand response in the future. To that end, the Commission required each RTO or ISO to assess and report on any remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction. The Commission further required each RTO's or ISO's Independent Market Monitor to submit a report describing its views on its RTO's or ISO's assessment to the Commission.

With regard to ***long-term power contracting***, the Commission required each RTO and ISO to dedicate a portion of its web sites for market participants to post offers to buy or sell power on a long-term basis.

To improve ***market monitoring***, the Commission required each RTO and ISO to provide its Market Monitoring Unit (MMU) with access to market data, resources and personnel sufficient to carry out their duties, and required the MMU to report directly to the RTO or ISO board of directors. In addition, the Commission required that the MMU's functions include: (1) identifying ineffective market rules and recommending proposed rules and tariff changes; (2) reviewing and reporting on the performance of the wholesale markets to the RTO or ISO, the Commission, and other interested entities; and (3) notifying appropriate Commission staff of instances in which a market participant's or the RTO's or ISO's behavior may require investigation.

The Commission also took the following actions with regard to MMUs: (1) expanded the list of recipients of MMU recommendations regarding rule and tariff changes, and broadened the scope of behavior to be reported to the Commission; (2) modified MMU participation in tariff administration and market mitigation, required each RTO and ISO to include ethics standards for MMU employees in its tariff, and required each RTO and ISO to consolidate all its MMU provisions in one section of its tariff; and (3) expanded the dissemination of MMU market information to a broader constituency, with reports made on a more frequent basis than in the past, and reduced the time period before energy market bid and offer data are released to the public.

Finally, the Commission established an obligation for each RTO and ISO to establish a means for customers and other stakeholders to have a form of direct access to the RTO or ISO board of directors, and thereby, increase its ***responsiveness to customers and other stakeholders***. The Commission stated that it will assess each RTO's or ISO's compliance filing using four responsiveness criteria: (1) inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority positions; and (4) ongoing responsiveness.

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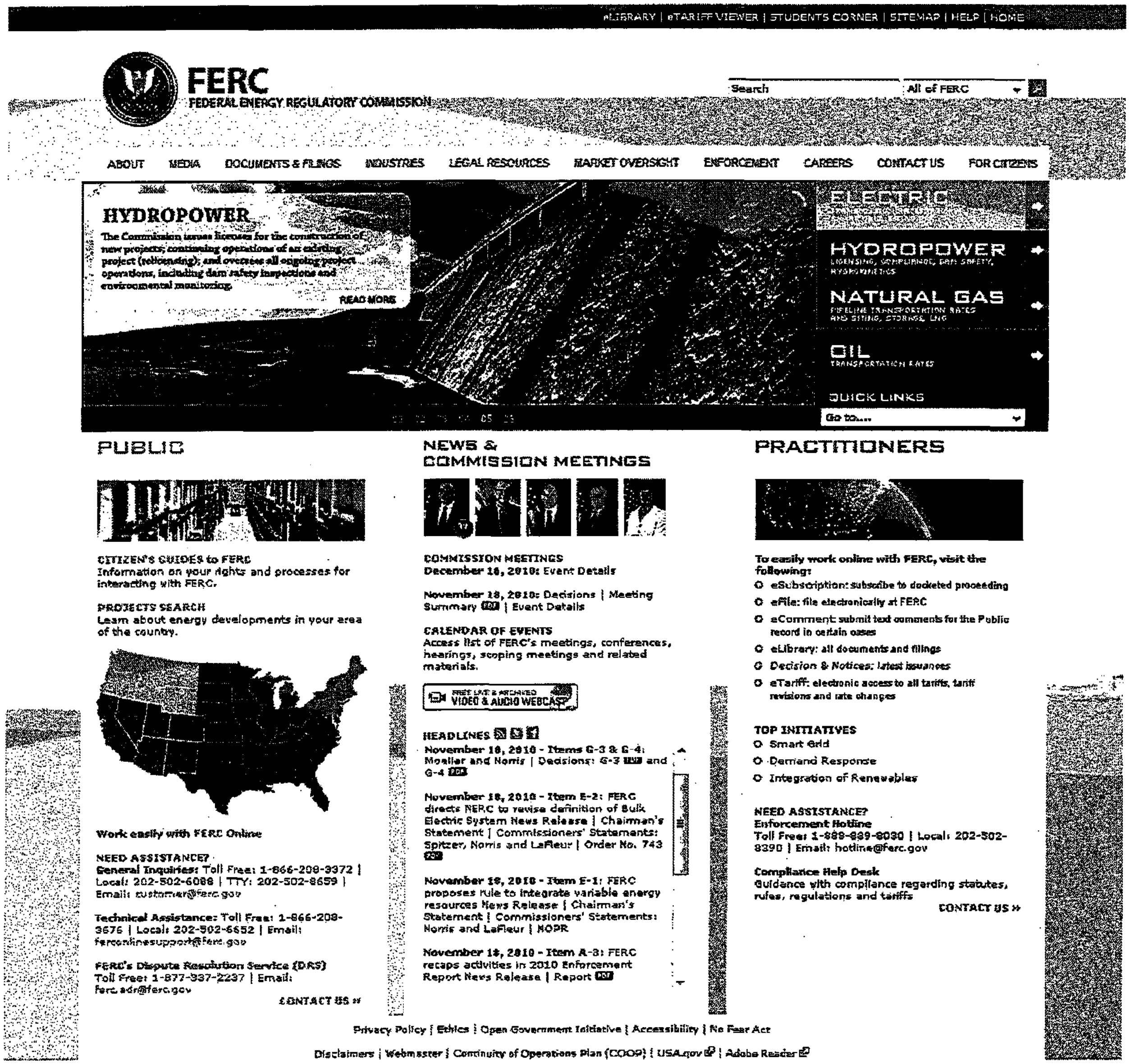

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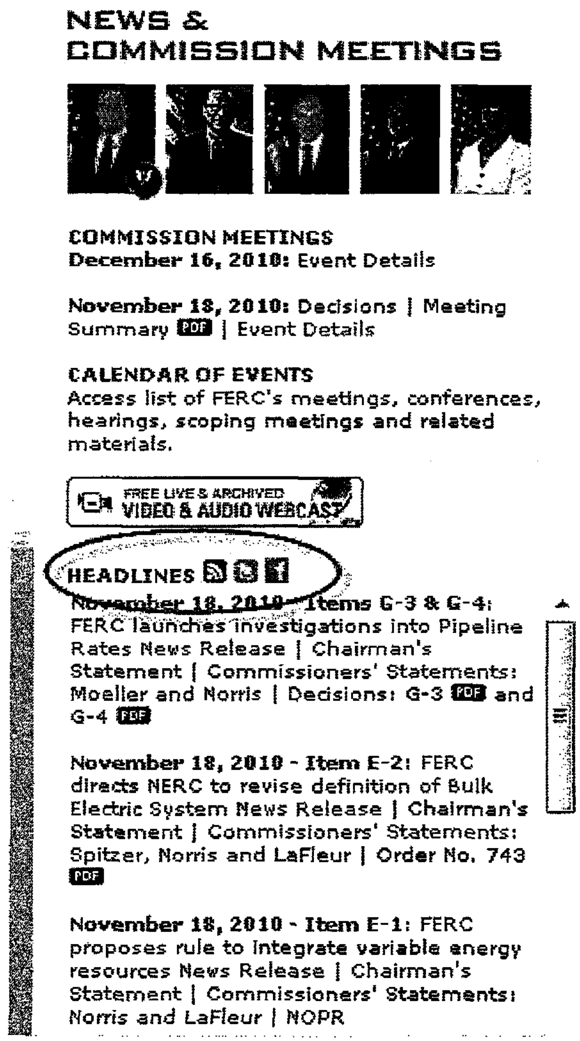

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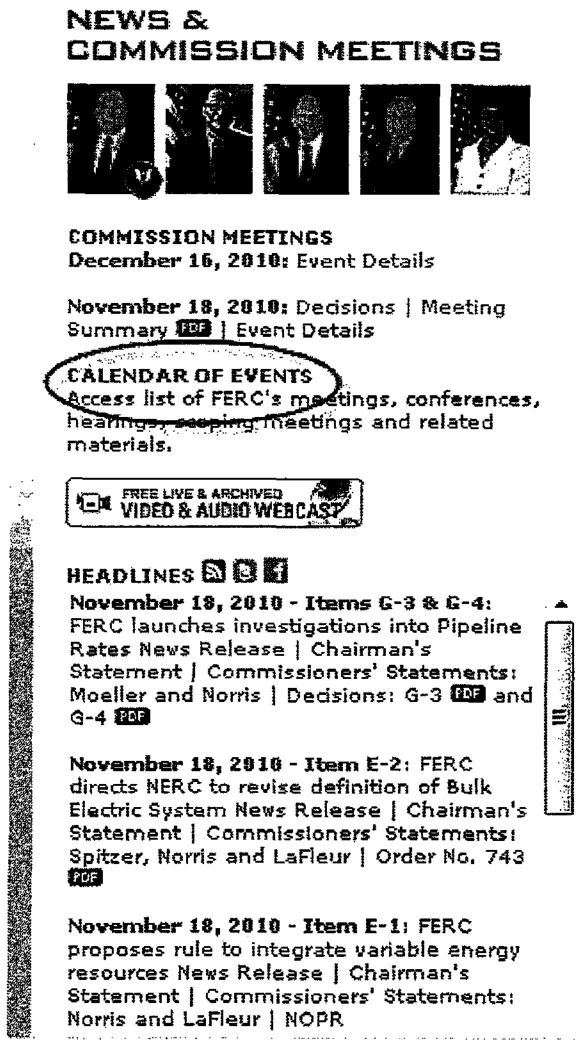

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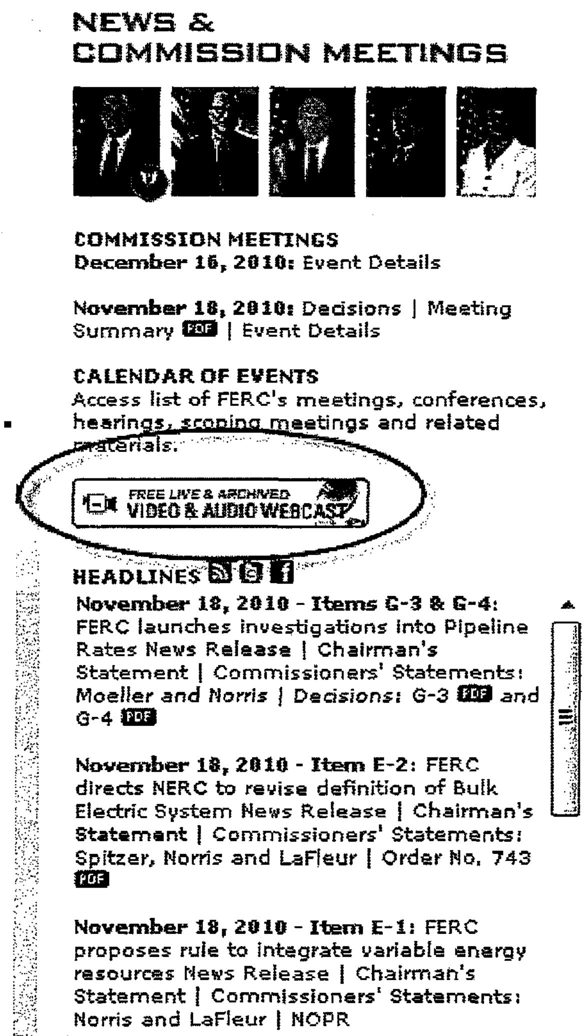

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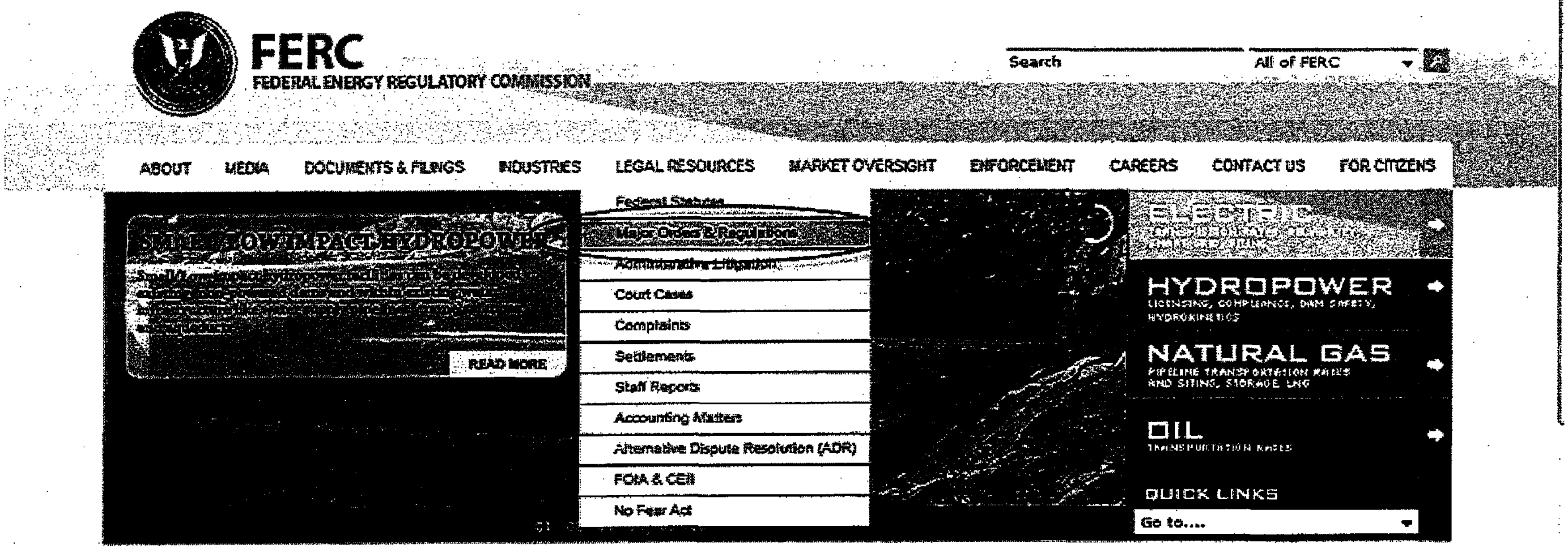

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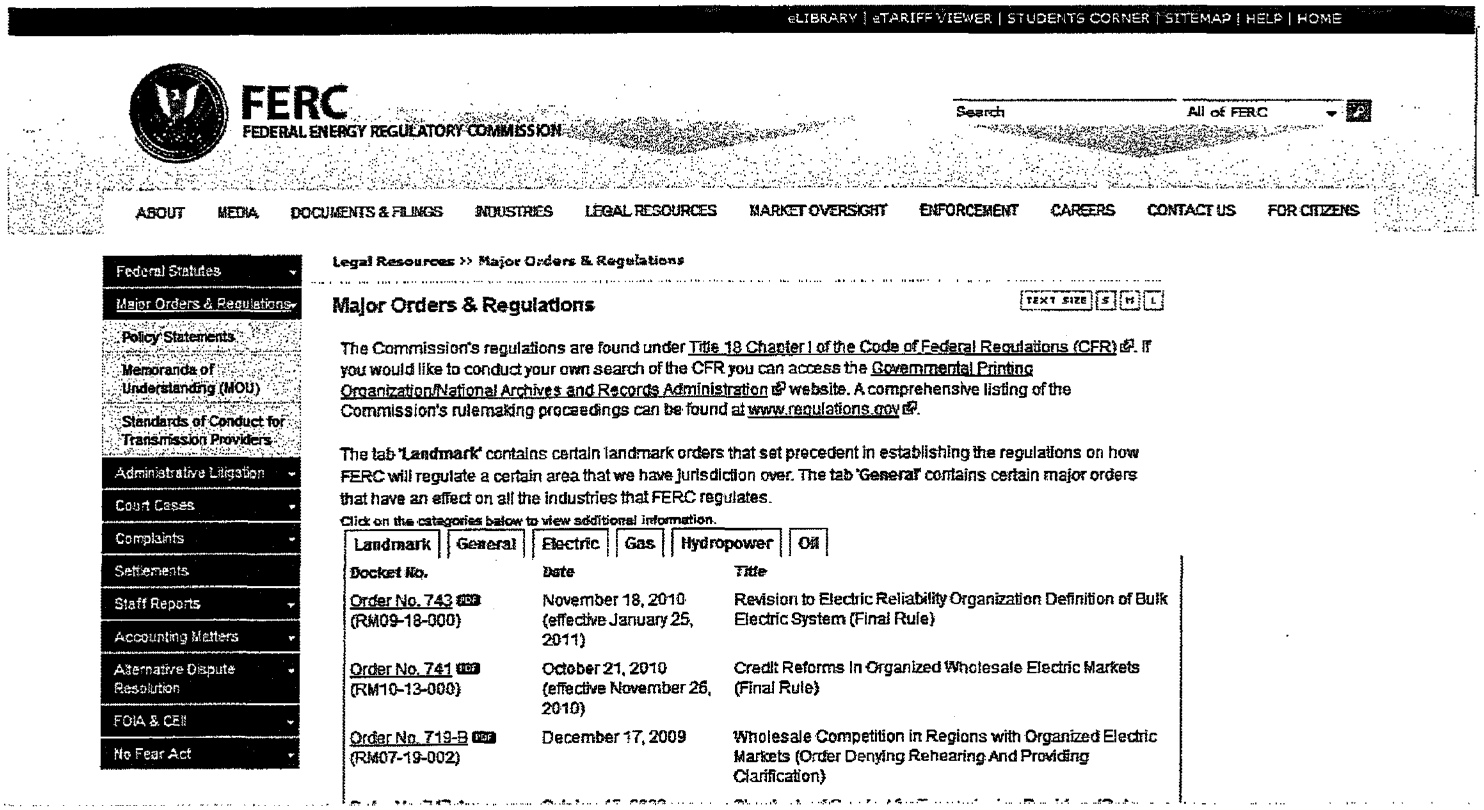

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Docket No.	Date	Title
Order No. 743 PDF (RM09-18-000)	November 18, 2010 (effective January 25, 2011)	Revision to Electric Reliability Organization Definition of Bulk Electric System (Final Rule)
Order No. 741 PDF (RM10-13-000)	October 21, 2010 (effective November 26, 2010)	Credit Reforms in Organized Wholesale Electric Markets (Final Rule)
Order No. 719-B PDF (RM07-19-002)	December 17, 2009	Wholesale Competition in Regions with Organized Electric Markets (Order Denying Rehearing And Providing Clarification)

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Thank you

Attachment 13

COMPETE Customer Members Oppose Monopoly Utility Regulation in Maryland

February 25, 2010

Chairman Douglas R. M. Nazarian
Maryland Public Services Commission
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

Dear Chairman Nazarian and members of the Public Service Commission: We write to offer the electricity customer's perspective in response to Governor O'Malley's December 18, 2009, letter urging the Maryland Public Service Commission to return to a form of monopoly regulation in Maryland by ordering new electricity generation to be built on a rate-regulated, cost-of-service basis.

As electricity customers in Maryland, we share the Governor's goal that all customers "have access to affordable, reliable and clean electricity." But we strongly disagree that the way to accomplish this objective is to re-monopolize the state's electricity industry. Maryland policymakers, like many others around the country, properly abandonedthe monopoly form of regulation due to its numerous failures, uneconomic outcomes, and vast inefficiencies. As was the case when Maryland policymakers decided to restructure the electric industry, a competitive electricity market is the most effective way to provide affordable, reliable and clean electricity, and to provide the choice, flexibility and innovation that job-producing businesses need.

In Maryland, we operate over 600 facilities, provide 29,600 jobs, and spend $61 million annually for electricity. As end users of electricity, we know first hand the benefits of competitive electricity markets – they allow businesses to recognize substantial savings on electricity costs and maintain low prices on goods and services, which can in turn be passed onto customers. Promoting policies that allow electricity users to manage energy purchases is critical to achieving such savings. Electricity is one of our largest operating costs and electric industry restructuring, the introduction of competition and customer choice, has provided us with the ability to achieve lower prices, and better manage and control those costs. Controlling operating costs is a critical element to growth and profitability which benefits our customers, employees, shareholders and the communities we serve.

The reality is that Maryland businesses can get fixed market prices for electricity for multiple years under contractual terms designed to fit our operations. In a period of economic uncertainty, thousands of Maryland businesses, from the very largest to the smallest, have realized appreciable savings by selecting new electric supply sources. These savings can be reinvested and provide Maryland businesses with a competitive advantage.

It is important to recognize that competition continues to expand in Maryland. Over 40% of Maryland's total electric usage is supplied from the competitive markets. Residential shopping has increased 40% in the last year and now stands at 80,000 customers. Indeed, Maryland's Department of General Services (DGS) is experiencing significant savings by having a choice in the competitive electric market. Last May, DGS announced $18.9 million in savings by purchasing electricity in an auction at prices that were on average 16% lower than in 2006.

The Governor's proposal for the Commission to order new power plant development under the abandoned monopoly cost-of-service model will impact the ability of customers to leverage the benefits of competition and experience the cost savings, cost control and innovation inherent in competitive power markets. Unfortunately, the Governor's proposal will lead to higher costs for Maryland businesses and consumers.

Allocating the costs of new utility generating plants to all rate payers will act as a tax on those who participate in the competitive market, thereby immediately raising our cost for power and inhibiting the independent power producers from building power plants in the PJM market. The impact on competition from this policy will chase competitive suppliers from the market, thereby decreasing the competitive pressures that keep costs down and spur innovation. This proposal would negatively impact the stability and certainty that Maryland's electric power market needs to attract investment, promote competition and increase jobs.

One of the most significant benefits of a competitive power market is that investors, not consumers, bear the investment and operating risks associated with the construction of power plants. Any program or policy that would reverse course and return to the high cost policies of the past will unnecessarily expose captive ratepayers to increased costs.

We understand the desire to have clean renewable power as part of the State's long-term energy strategy. Before embarking on major policy changes, Maryland should take note that PJM is already attracting renewable wind resources as well as demand response and energy efficiency resources to help Maryland meet its environmental objectives. There are now 2,500 MW's of wind on the PJM grid with 1,800 MW's under construction and another 42,000 MW's in the queue. It is important to keep in mind that organized competitive markets like PJM's generally do an excellent job attracting "green" and innovative technologies. A competitive power market is the best means to achieve I initiatives, including wind and solar energy, energy efficiency and green building design.

As electricity consumers and Maryland employers, we have been active participants in the processes before both the Legislature and the Commission. We continue to support he competitive wholesale and retail market policies that are now in place because they are continuously improving, empower our businesses to be more efficient, and give rate payers more effective means to control energy costs. Markets provide cost control, innovative products and services, and help businesses remain competitive which supports growth that benefits Maryland citizens. We strongly urge the Commission to preserve the current pro-competition and customer choice policies essential to Maryland businesses and consumers.

Sincerely,

W.J. Balsamo
Corporate Energy Manager
PetSmart, Inc.

Angela S. Beehler
Sr. Director of Energy Regulation
Wal-Mart Stores, Inc.

Jeff Dummermuth
Director, Energy & Engineering
Big Lots Stores, Inc.

Steve Elsea
Director of Energy Leggett & Platt, Inc.

George Waidelich
Vice President - Energy Operations
Safeway Inc.

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Attachment 14

Pennsylvania Public Utility Commission
Commonwealth of Pennsylvania
Harrisburg, Pennsylvania

July 13, 2011

Member, Pennsylvania Congressional Delegation
United States Congress
Washington, D.C. 20510

Dear Senator or Representative:

We are writing to express our support for a recent decision by the Federal Energy Regulatory Commission (FERC) that changes the rules governing the electricity capacity market operated by the PJM Interconnection, Inc. (PJM).[1] While we are aware that certain parties are advocating for FERC to reverse its decision on rehearing, the Pennsylvania Public Utility Commission (PA PUC) believes FERC's decision was well-reasoned and should remain unmodified.

By way of background, the commodity traded in a capacity market is the right to call on electric generation capacity in future years to meet certain reliability requirements. This is different than the energy market where the commodity sold is the actual electricity (kWh) that will be used to meet consumers' needs.

PJM's capacity market – the Reliability Pricing Model (RPM) – focuses on securing commitments from resources to provide capacity three years in advance. The purpose of the RPM is to provide economic incentives to attract investment in new and existing capacity resources in PJM (as needed) to maintain the reliability of the bulk power system. PJM's capacity market contains an auction structure through which capacity resources compete to obtain a market-based capacity payment in exchange for a commitment to be available in the years ahead to meet the region's electricity needs.

Well-functioning capacity markets are a critical component of current wholesale restructured electricity markets in the PJM region. By placing a tradable value on the availability of generation capacity, capacity markets remove some of the financial risk of building generation facilities in a competitive market where cost-recovery is not as certain as it might be in a regulated market. This encourages investment in new generation and helps to ensure there will be enough generation to meet the demand for electricity in this country for years to come.

[1] *See PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011). PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

In order for capacity markets to function properly and produce competitive outcomes, it is critical that buyers and sellers in the market receive accurate price signals. To help ensure accurate price signals, the rules governing PJM's capacity market contain a mechanism – the Minimum Offer Price Rule (MOPR) – which is designed to prevent market power manipulation in the annual RPM capacity auction. The MOPR provides that PJM will reject and substitute any auction bids that are deemed to be too low, and thus, would skew the market.

On February 11, 2011, PJM filed a request with FERC to update and simplify its MOPR tariff provisions. One of the motivations behind this filing was the passage of a recent New Jersey law that had the potential to facilitate buyer market power in PJM's capacity market. The law provides for New Jersey to procure up to 2,000 MW of new capacity, requires this new capacity to clear in the RPM auction through an offer price which may be below its costs, and grants subsidies to the new capacity in the form of additional out-of-market revenue if offer prices are below cost. By providing subsidies to this new state-sponsored generating capacity, the New Jersey Law would enable that new capacity to bid into the RPM auction at potentially artificially low levels, skewing the results of the competitive auction. As PJM's Independent Market Monitor explained, this could artificially depress RPM auction prices below the competitive level, ultimately resulting in less investment in new and existing capacity.[2]

Despite the potential impact of the New Jersey law, PJM's original MOPR rule did not give PJM or FERC the clear authority to examine the impact of any RPM bids made pursuant to the New Jersey Law. In an effort to clarify situations such as this one, where state-mandated subsidies could impact the market, PJM submitted its filing with FERC to revise the MOPR tariff provisions, which the PA PUC supported. In an order issued on April 12, 2011, FERC largely agreed with PJM and accepted the majority of PJM's suggested revisions to the MOPR.

Certain parties have objected to FERC's decision. In comments submitted to FERC, New Jersey has given many explanations for the passage of its law and reasons why the FERC decision should be reversed on rehearing. New Jersey's primary argument is that the RPM is not working for New Jersey and has failed to attract new generation to the state. However, as a neighboring state to New Jersey and member of PJM, Pennsylvania objects to the argument that RPM has not been successful in encouraging the construction of new generation in Pennsylvania. Since the creation of the RPM in 2007, Pennsylvania has attracted a significant amount of new generation to the state and remains a net exporter of electricity. In contrast, if no new generation has been built in New Jersey in the existing market, it likely means that the market does not support such construction for what could be a variety of reasons, including market price issues.

The RPM is designed to give market signals to attract new generation to certain locations when needed. However, as mentioned above, the ability to bid in new capacity at potentially artificially low prices can skew the capacity market leading to less investment in new and existing capacity, including in Pennsylvania. Without such investment, the end result from the consumer's perspective, ultimately, could be higher rates in Pennsylvania than without this state-mandated subsidy

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[2] *Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market*, Independent Market Monitor for PJM (Jan. 6, 2011).

Other parties have argued that FERC's decision infringes on states' rights to design their own energy policies. The PA PUC disagrees with this line of reasoning as well. Under FERC's decision, the only capacity bids that would be mitigated under the MOPR are the bids that are too low, meaning they do not reflect the actual cost of building or operating that type of capacity and would skew the supply and demand balance that sets the true market price. Similarly, under the FERC decision, the only capacity bids that would fail to clear in the RPM auction are ones that are uneconomic, meaning they are too expensive to build or operate. Thus, any party that wants to use or construct capacity outside of these bounds is either seeking to build uneconomic capacity or is simply trying to manipulate the market. The rules that FERC accepted in its order ensure that the RPM market remains competitive and free of manipulation, while still leaving states free to pursue any capacity projects that are economically sound.

It is possible that New Jersey's Congressional Delegation may attempt gain your support for a measure circumventing FERC's regulatory jurisdiction, either through legislation or alternative measures. We strongly urge that you do not support any such initiative for reasons outlined above.

The PA PUC believes FERC's recent decision accepting PJM's revisions to the rules governing the RPM was well-reasoned and should stand. FERC has a wealth of knowledge on these issues and PA PUC believes that Congress should defer to the agency's expertise on this matter. If you are interested in additional information explaining our position on this issue, we have attached the comments the PA PUC filed with FERC in the above-referenced proceeding.

We appreciate your favorable consideration of this request and please do not hesitate to contact us if you have any questions.

Sincerely,

Robert F. Powell

ROBERT F. POWELSON, *Chairman*

JOHN F. COLEMAN, Jr., *Vice-Chairman*

WAYNE E. GARDNER, *Commissioner*

James H Cawley

JAMES H. CAWLEY, *Commissioner*

Pamela A. Witmer

PAMELA A. WITMER, *Commissioner*

Attachment 15

News Release
August 08, 2013

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ERCOT experiences highest demand this year, generation keeps up

AUSTIN, TX, Aug. 8, 2013 — Demand for power on the grid that serves most of Texas hit the third highest level in its history on Wednesday, Aug. 7.

Peak electric use within the Electric Reliability Council of Texas (ERCOT) region topped out at 67,180 megawatts (MW) during the 4-5 p.m. hour. The grid experienced no problems during the day, with more than 74,000 MW of electricity, including more than 2,300 MW of wind power, available during the peak hour.

"We appreciate all the work by transmission and generating companies to keep the power flowing on this very hot day," said Kenneth McIntyre, ERCOT's vice president for Grid Planning and Operations.

This was the highest demand so far in 2013, which has included a mild summer compared to 2012 and the record-breaking 2011, Texas' hottest summer on record. ERCOT's record peak occurred on Aug. 3, 2011, when demand hit 68,305 MW. One MW is typically enough electricity to power about 200 homes during peak demand.

"Until this week, peak demand and overall energy use have been lower this summer than in the past couple of years," noted McIntyre. "Of course, August is typically the hottest month of the year, so we may see several more days like this before the summer ends, and we still may need to ask consumers to be especially mindful of their electricity use on some of those days."

ERCOT demand exceeded 65,000 MW for the first time this year on Aug. 1, compared to June 25 last year and July 25 in 2011.

The fuel mix powering the grid during Wednesday's peak included 59.3 percent natural gas, 29.2 percent coal, 7.5 percent nuclear, 3.4 percent wind, 0.3 percent diesel generation, 0.2 percent solar and biomass, and 0.1 percent hydroelectric power.

Here are ERCOT's top five demand days.*

1. 68,305 MW, Aug. 3, 2011
2. 67,929 MW, Aug. 2, 2011
3. 67,180 MW, Aug. 7, 2013
4. 66,867 MW, Aug. 1, 2011
5. 66,849 MW, Aug. 4, 2011

*Please note that older records are adjusted based on final settlement over time, while more recent records are based on operational data.

Anyone who is interested in how the grid is operating can follow hourly demand and capacity trends throughout the day on ERCOT's website at www.ercot.com or on its free ERCOT

Energy Saver mobile app for Android and Apple devices, available for download at Google Play or the Apple App Store. The mobile app will begin offering even more features, including real-time wholesale prices, later this month.

###

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 23 million Texas customers -- representing 85 percent of the state"s electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 6.7 million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT"s members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

Contact

Robbie Searcy (512) 225-7213

rsearcy@ercot.com

Attachment 16

Draft – 11/6/2011

New York Control Area Installed Capacity Requirements For the Period May 2012 through April 2013

Technical Study Report

December __, 2011

New York State Reliability Council, LLC
Installed Capacity Subcommittee

TABLE OF CONTENTS *[To be prepared]*

EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. This year's report covers the period May 2012 to April 2013 (2012 Capability Year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2012 Capability Year is 16.1% under base case conditions.

This study also determined Minimum Locational Capacity Requirements (MLCRs) of 83.9% and 99.2% for New York City (NYC) and Long Island (LI), respectively. In its role of setting the appropriate locational capacity requirements (LCRs), the New York Independent System Operator (NYISO) will consider these MLCRs.

These study results satisfy and are consistent with NYSRC Reliability Rules, Northeast Power Coordinating Council (NPCC) reliability criteria, and North American Electric Reliability Corporation (NERC) reliability standards.

The 16.1% IRM base case for 2012 represents a *0.6% increase* from the 2011 base case IRM of 15.5%. Table 1 shows the IRM impacts of individual study parameters that result in this change. The principal drivers that increased the required IRM are:

- A 337 MW increase in wind-powered generation
- Updated NYCA purchase and sale capacity projections
- Reduced availability of NYCA generating units

The above IRM drivers together accounted for an IRM increase of 1.3% from the 2011 base case value. There were several updated study parameters that reduced the IRM.

Over the next decade, several state and federal environmental regulations will affect generation resources in New York State. The only regulation that could possibly affect generation operations in the 2012 Capability Year is the newly enacted Cross State Air Pollution Rule (CSAPR). Overall, CSAPR will affect 167 generating units representing 23,275 MW of capacity in New York. Although the regulation requirements will start in 2012, a NYISO analysis showed that the NYCA can operate reliably with the program in 2012 without impacting IRM requirements.

This study also evaluated IRM impacts of several sensitivity cases. These results are summarized in Table 2 and in greater detail in Appendix Table B-2. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case 16.1% IRM will fully meet NYSRC and the NPCC resource adequacy criteria.

The base case and sensitivity case IRM results, along with other relevant factors, will be considered in a separate NYSRC Executive Committee process in which the Final NYCA IRM requirement for the 2012 Capability Year is adopted.

INTRODUCTION

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA IRM for the period of May 1, 2012 through April 30, 2013 (2012 Capability Year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

ICR = (1 + %IRM Requirement/100) x Forecasted NYCA Peak Load

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2012 Capability Year.

The NYISO will implement the final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules and the NYISO Installed Capacity (ICAP) Manual. The NYISO translates the required IRM to an Unforced Capacity (UCAP) basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. These UCAP and Demand Curve concepts are described later in the report. The schedule for conducting the 2012 IRM Study was based on meeting the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2012 IRM Study are in accordance with NYSRC Policy 5-5, *Procedure for Establishing New York Control Area Installed Capacity Requirement.* The primary reliability criterion used in the IRM study requires a Loss of Load Expectation (LOLE) of no greater than 0.1 days/year for the NYCA. This NYSRC resource adequacy criterion is consistent with NPCC reliability criteria and NERC reliability standards. IRM study procedures include the use of two study methodologies, the *Unified* and the *IRM Anchoring Methodologies*. The above reliability criterion and methodologies are discussed in more detail later in the report. In addition to calculating the NYCA IRM requirement, these methodologies identify corresponding MLCRs for NYC and LI. In its role of setting the appropriate LCRs, the NYISO will utilize the same study methodologies and procedures as in the 2012 IRM Study, and will consider the MLCR values determined in this study.

Two major improvements in the IRM study process were implemented in the 2012 IRM Study. First, the process for reviewing input data accuracy was improved. Second, a preliminary base case was prepared which was used as the basis for conducting sensitivity studies and data accuracy review. These study improvements are described in the report.

Previous NYCA 2000 to 2011 IRM Study reports can be found at www.nysrc.org/reports.asp. Table B-1 in Appendix B provides a comparison of previous NYCA base case and final IRMs for the 2000 through 2011 Capability Years. This table also shows UCAP reserve margins over this period. Definitions of certain terms in this report can be found in the Glossary section of the Appendix.

NYSRC RESOURCE ADEQUACY RELIABILITY CRITERION

The acceptable LOLE reliability level used for establishing NYCA IRM Requirements is dictated by the NYSRC Reliability Rule A-R1, *Statewide Installed Reserve Margin Requirements,* which states:

> *The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.*

This NYSRC Reliability Rule is consistent with NPCC Resource Adequacy Design Criteria in Section 5.2 of NPCC Directory 1, *Design and Operation of the Bulk Power System.*

In accordance with NYSRC Rule A-R2, *Load Serving Entity (LSE) Installed Capacity Requirements*, the NYISO is required to establish LSE installed capacity requirements, including locational capacity requirements, in order to meet the statewide IRM Requirements established by the NYSRC for maintaining NYSRC Rule A-R1 above. The full NYSRC Reliability Rule A-R2 can be found in the NYSRC Reliability Rules Manual on the NYSRC Web site, at
www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

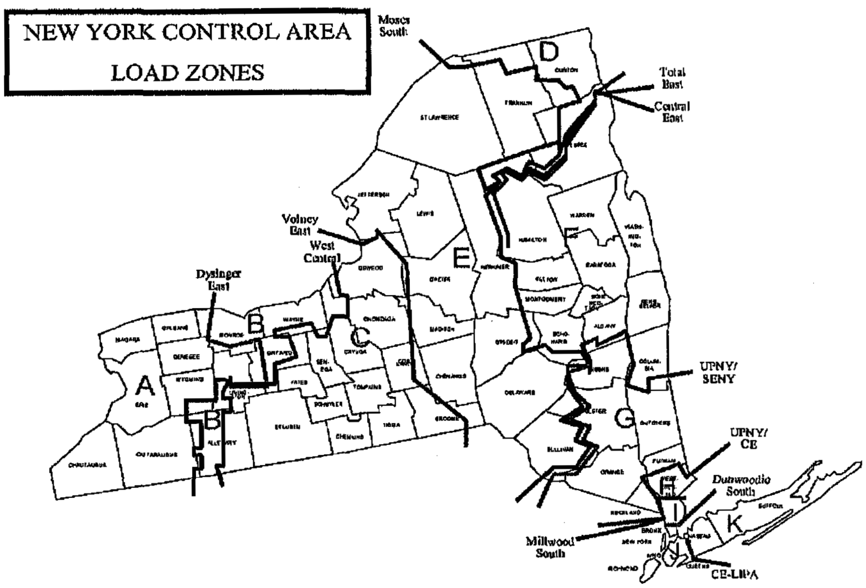
IRM STUDY PROCEDURES

The study procedures used for the 2012 IRM Study are described in detail in NYSRC Policy 5-5, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-5 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study. Policy 5-5 can be found on the NYSRC Web site at, www.nysrc.org/policies.asp.

This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the days per year of expected resource capacity shortages.

General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. The external Control Areas are: Ontario, New England, Quebec, and the PJM Interconnection. The eleven NYCA zones are depicted in Figure 1 below. GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability. The GE-MARS program is described in detail in Appendix A.

Figure 1: NYCA Load Zones



Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs, as illustrated in Figure 2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. Note that all points above the curve are more reliable than criteria, and vice versa. This methodology develops a pair of curves, one for NYC (Zone J) and one for LI (Zone K). Appendix A of Policy 5-5 provides a more detailed description of the Unified Methodology.

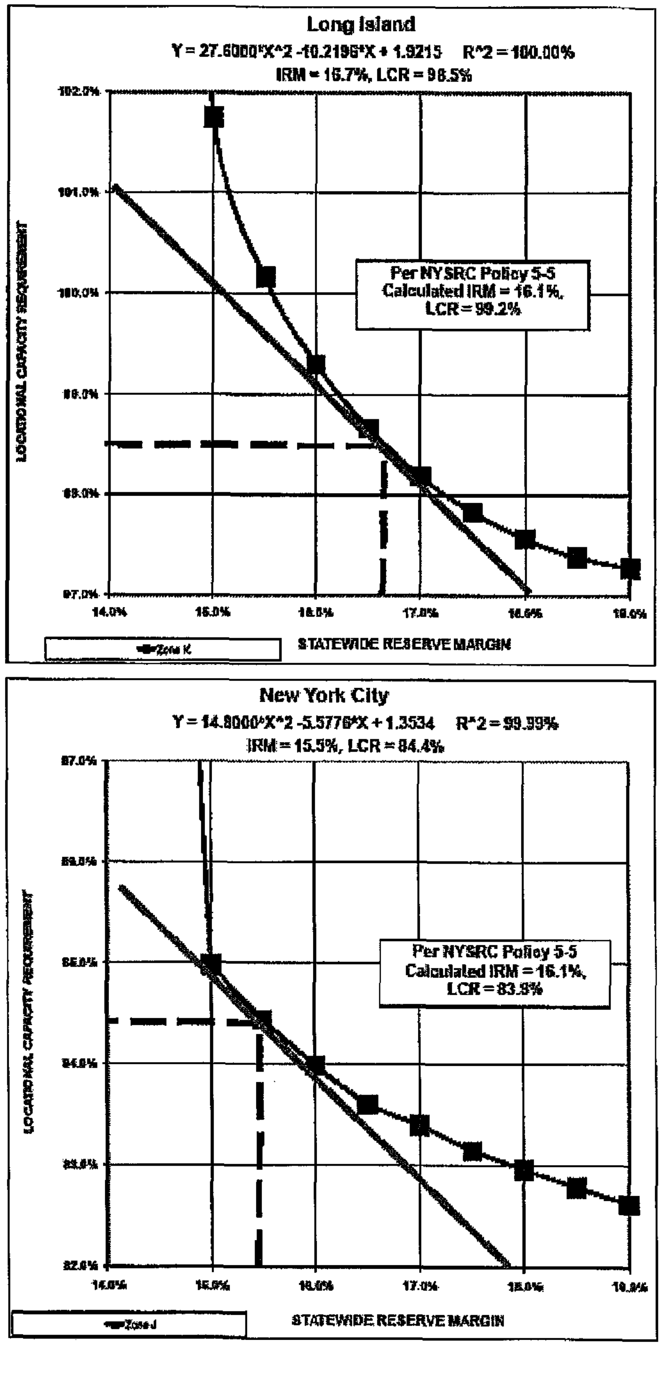
Base case NYCA IRM requirements and related MLCRs are established by a supplemental procedure (termed the *IRM Anchoring Methodology*) which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the bend (or "knee") of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan 45 degree inflection point. Appendix B of Policy 5-5 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

BASE CASE STUDY RESULTS

Results of the NYSRC technical study show that the required NYCA IRM is 16.1% for the 2012 Capability Year under base case conditions. Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI.

Figure 2: NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements

NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements



The tangent points on these curves were evaluated using the Tan 45 analysis. Accordingly, it can be concluded that maintaining a NYCA installed reserve of 16.1% for the 2012 Capability Year, together with MLCRs of 83.9% and 99.2% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.

Comparing these results to the 2011 IRM Study, the 83.9% NYC MLCR increased 2.9%, while the LI MLCR decreased 2.1%. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2012 Capability Year.

A Monte Carlo simulation error analysis shows that there is a __% probability that the above base case result is within a range of __% and __% (see Appendix A). Within this range the statistical significance of the __%, __%, and __% numbers are a __%, 50%, and __% probability of meeting the one day in ten LOLE, assuming perfect accuracy of all parameters and using a standard error of 0.05. If a standard error of 0.025 were used, the band would tighten from __% to __%. This analysis demonstrates that there is a high level of confidence that the base case IRM value of __% is in full compliance with NYSRC and NPCC reliability rules and criteria.

MODELS AND KEY INPUT ASSUMPTIONS

This section describes the models and related input assumptions for the 2012 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission System Model, and Outside World Model.* Potential IRM impacts of pending environmental initiatives are also addressed. The input assumptions for the base case were based on information available prior to October 1, 2011. Appendix A provides more details of these models and assumptions. Table A-4 compares key assumptions with those used for the 2011 IRM Study.

Load Model

- ***Peak Load Forecast:*** A 2012 NYCA summer peak load forecast of 33,335 MW was assumed in the study, an increase of 463 MW from the 2011 summer peak forecast used in the 2011 IRM Study. The 2012 load forecast was completed by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force on October 3, 2011, and considers actual 2011 summer load conditions. Use of this 2012 peak load forecast in the 2012 IRM study had no impact on IRM requirements compared to the 2011 Study (Table 1). The NYISO will prepare a final 2012 summer forecast in early 2012 for use in the NYISO 2012 Locational Capacity Requirement Study. It is expected that the NYISO's October 2011 summer peak load forecast for 2012 and the final 2012 forecast will be similar.

- ***Load Shape Model:*** The 2012 IRM Study was performed using a load shape based on 2002 actual values. This same load shape was used in the five previous IRM studies and is consistent with the load shape assumption used by adjacent NPCC Control Areas. An analysis comparing the 2002 load shape to actual load shapes from 1999 through 2010 concluded that the 2002 load shape continues to be the best suited for the 2012 IRM Study.

- ***Load Forecast Uncertainty (LFU):*** It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather and economic conditions. Recognizing the unique LFU of individual NYCA areas, separate LFU models are prepared for four areas: New York City (Zone J), Long Island (Zone K), Westchester (Zones H and I), and the rest of New York State (Zones A-G).

  The load forecast uncertainty models and data used for the 2012 IRM Study were updated by Consolidated Edison for Zones H, I, and J; Long Island Power Authority (LIPA) for Zone K; and the NYISO. Appendix Section A-5.2.1 describes these models in more detail. Recognition of load forecast uncertainty in the 2012 IRM Study has an effect of increasing IRM requirements by 6.3%. Use of updated LFU models for the 2012 IRM Study decreased IRM requirements by 0.2% from the 2012 IRM Study.

Capacity Model

The capacity model in MARS incorporates several considerations, as discussed below:

- ***Planned Non-Wind Facilities, Retirements and Reratings:***

  Planned non-wind facilities and retirements that are represented in the 2012 IRM Study are shown in Appendix A. This includes the addition of 22.5 MW of solar capacity located on Long Island. The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual. Planned non-wind facilities, retirements and reratings had the overall effect of decreasing the IRM by 0.3% from the 2011 IRM Study. Appendix A shows the ratings of all resource facilities that are included in the 2011 IRM Study capacity model.

- ***Wind Generation:***

  It is projected that by the end of the 2012 summer period there will be a total wind capacity of 1,648 MW in New York State. All wind farms are located in upstate New York, in Zones A-E. See Appendix A for details. The 2012 summer period wind capacity projection is 337 MW higher than the forecast 2011 wind capacity assumed for the 2011 IRM Study.

  The 2012 IRM Study base case assumes that the projected 1,648 MW of wind capacity will operate at an 11.0% capacity factor during the summer peak period. This assumed capacity factor is based on an analysis of actual hourly wind generation data collected for wind facilities in New York State during the June through August period, between the hours of 2:00 p.m. and 5:00 p.m. This test period was chosen because it covers the time when virtually all of the annual NYCA LOLE is distributed.

The increase in projected wind capacity from the value of 1,333 MW used in the 2011 IRM Study, to 1,648 MW forecast used for this study, results in a 0.5% increase to the IRM (Table 1).

Overall, inclusion of the projected 1,648 MW of wind capacity in the 2012 Study accounts for 4.7% of the 2011 IRM requirement (Table 2). This relatively high IRM impact is a direct result of the very low capacity factor of wind facilities during the summer peak period. The impact of wind capacity on *unforced capacity* is discussed in Appendix B, Section B-3, "The Effect of Wind Resources on the NYCA IRM & UCAP Markets." A detailed summary of existing and planned wind resources is shown in Appendix A, Section A-5.8.

- ***Generating Unit Availability:***

  Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an equivalent forced outage rate (EFOR) for each unit represented. Outage data used to determine the EFOR is received by the NYISO from generator owners based on outage data reporting requirements established by the NYISO. Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period – the time span considered for the 2012 IRM Study covered the 2006-2010 period. The five-year EFOR calculated for this period slightly exceeded the 2005-2009 average value used for the 2011 IRM Study, causing the IRM to increase by 0.4% (Table 1). Figure A-5 depicts NYCA 2001 to 2010 EFOR trends.

  In past NYSRC IRM studies, the model used to represent thermal generator outage rates has been based on the calculation of an EFOR, irrespective of the demand. However, the NYISO uses the concept of Unforced Capacity (UCAP) to establish both the LSE obligation to buy, and the amount each generator can sell into the capacity market. UCAP values are derived from the Equivalent Forced Outage Rate during demand periods (EFORd). Since EFORs are the same or lower than EFORds, the model's representation in past IRM studies has been considered conservative in that it calculates an IRM that is higher than would be calculated if EFORd was used as the basis.

  Over the past year, the ICS has investigated a method by which transition rates (used as the model input to represent forced outage rates) can be developed to better match the market's EFORd values. An independent consulting firm, Associated Power Analysts (APA), was retained by the NYISO to help develop this method. Although the APA/EFORd method has not been fully developed, tested and reviewed by ICS as of November 2011, a sensitivity case was prepared to demonstrate the approximate IRM impact of implementing the APA/EFORd method.

  The IRM impact of this sensitivity case is shown in Table 2 (Case13). As expected, use of the new EFORd model results in a lower IRM; however, the magnitude of the IRM reduction is uncertain until the model is fully developed and validated. It is expected that the new EFORd model will be implemented in the 2013 IRM Study once approved by ICS.

- *Capacity Availability of Firm Purchases and Sales:*

  The availability of the resources participating in the New York market changes as firm sales and purchases change. Highly available resources acquired through capacity purchases reduce IRM requirements. Similarly, firm sales of highly available resources increase the IRM. Firm capacity sales that were modeled in the 2011 IRM Study as a result of New England's Forward Capacity Market (FCM) have dissolved as those contracts were bought out by internal New England resources. As a result of this activity, those units which were scheduled to supply capacity to New England from New York now participate in the New York market.

  The overall availability of those returning units was lower than that of the existing resource mix. As a result, the IRM increased by 0.4% (Table1).

- *Emergency Operating Procedures (EOPs):*

  -- **Special Case Resources (SCRs)**. SCRs are ICAP resources that include loads that are capable of being interrupted on demand and distributed generators that may be activated on demand. This study assumes a SCR base case value of 2,192 MW in August 2012 with lesser amounts during other months based on historical experience.

  The SCR performance model is based on an analysis of historical SCR load reduction performance which is described in Section A-5.3 of Appendix A. Due to the possibility that some of the potential SCR program capacity may not be available during peak periods, projections are discounted for the base case based on previous experience with these programs, as well as any operating limitations. An updated SCR model used for the 2012 IRM Study resulted in an IRM decrease of 0.3% from the 2011 IRM Study (see Table 1). This was primarily due to an improved methodology for assessing performance of SCR resources. SCRs, because of their obligatory nature, are considered capacity resources in setting the IRM.

  -- **Emergency Demand Response Programs (EDRP)**. EDRP allows registered interruptible loads and standby generators to participate on a voluntary basis – and be paid for their ability to restore operating reserves. The 2012 Study assumes 148 MW of EDRP capacity resources will be registered in 2012, a reduction from 2011. This EDRP capacity was discounted to a base case value of 95 MW reflecting past performance, and is implemented in the study in July and August (lesser amounts during other months), while being limited to a maximum of five EDRP calls per month. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model. Unlike SCRs, EDRP are not considered capacity resources because they are not required to respond when called upon to operate.

  -- **Other Emergency Operating Procedures.** In accordance with NYSRC criteria, the NYISO will implement EOPs as required to minimize customer disconnections. Projected 2012 EOP capacity values are based on recent actual data and NYISO forecasts. (Refer to Appendix B, Table B-3, for the expected use of SCRs, EDRP, voltage reductions, and other types of EOPs during 2012.). The updated EOP model, excluding the SCR impact noted above, slightly decreased the IRM from the 2011.

- ***Unforced Capacity Deliverability Rights (UDRs):***

  The capacity model includes UDRs which are capacity rights that allow the owner of an incremental controllable transmission project to extract the locational capacity benefit derived by the NYCA from the project. Non-locational capacity, when coupled with a UDR, can be used to satisfy locational capacity requirements. The owner of UDR facility rights designates how they will be treated by the NYSRC and NYISO for resource adequacy studies. The NYISO calculates the actual UDR award based on the performance characteristics of the facility and other data.

  LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, 660 MW HVDC Neptune Cable, and the 300 MW Linden Variable Frequency Transformer (VFT) project are facilities that are represented in the 2012 IRM Study as having UDR capacity rights. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance which may reduce locational and IRM requirements. The 2012 IRM study incorporates the elections that these facility owners made for the 2012 Capability Year.

Transmission System Topology

A detailed transmission system model is represented in the GE-MARS study. The transmission system topology, which includes eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Figure A-13 in Appendix A. The transfer limits employed for the 2012 IRM Study were developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional analysis conducted specifically for the GE-MARS representation.

Failure rates for overhead lines and underground cables are similar, but the repair time for an underground cable is much longer. Therefore, forced transmission outages are included in the GE-MARS model for the underground cable system from surrounding zones entering into New York City and Long Island. The GE-MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are calculated based on the individual make-up of each interface, which includes failure rates and repair times for the cable, and for any transformer and/or phase angle regulator on that particular cable. A recent extended cable outage caused an increase in the average cable forced outage rate (FOR), resulting in a slight IRM increase.

The NYCA transmission topology remains relatively consistent between the 2011 and 2012 IRM studies.. The only change is the announced retirement of the Far Rockaway and Glenwood generating units on Long Island. The loss of this 235 MW of generation capability results in less transfer capability from Long Island into the New York City and the Upstate zones. This reduced capability, however, does not result in an increased IRM because the flows on these lines are predominately toward Long Island. Appendix A describes the basis for this change in more detail.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. The 2012 IRM study, as with previous GE-MARS studies, reveals that the transmission system into NYC and LI is constrained and can impede the delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints: (1) the NYCA IRM requirement considers transmission constraints into NYC and LI, and (2) minimum LCRs must be maintained for both NYC and LI (refer to the NYSRC Resource Adequacy Reliability Criteria section).

The impact of transmission constraints on NYCA IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements,* the NYISO is required to calculate and establish appropriate LCRs. The most recent NYISO study (*Locational Installed Capacity Requirements Study,* dated January 14, 2011, at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp, determined that for the 2011 Capability Year, the required LCRs for NYC and LI were 81.0% and 101.5%, respectively. A LCR Study for the 2012 Capability Year is scheduled to be completed by the NYISO in January 2012.

Results from 2012 IRM Study illustrate the impact on the IRM requirement for changes of the base case NYC and LI LCR levels of 83.9% and 99.2%, respectively. Observations from these results include:

- **Unconstrained NYCA Case** – If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 13.8%, 2.3% less than the base case IRM requirement. (See Table 2.) As a result, relieving NYCA transmission constraints would make it possible to reduce the 2012 NYCA installed capacity requirement by approximately 770 MW.

- **Downstate NY Capacity Levels** – If the NYC and LI LCR levels were *increased* from the base case results to 85% and 102%, respectively, the 2012 IRM requirement could be reduced by 1.1%, to 15.0%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 83.0% and 97.5%, respectively, the IRM requirement must increase by 1.9%, to 18.0%. (Figure 2.)

These results illustrate the significant impact on IRM caused by transmission constraints and implementing different LCR levels, assuming all other factors being equal.

Outside World Model

The Outside World Model consists of those Control Areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection. NYCA reliability can be improved and IRM requirements can be reduced by recognizing available emergency capacity assistance support from these neighboring interconnected control areas — in accordance with control area agreements during emergency conditions. Representing such interconnection support arrangements in the 2012 IRM Study base case reduces the NYCA IRM requirements by 8.6% (Table 2). A model for representing neighboring control areas, similar to previous IRM studies, was utilized in his study.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency assistance support. For this purpose, from Policy 5-5, a rule is applied whereby an Outside World Area's LOLE cannot be lower than its own LOLE criterion, its isolated LOLE cannot be lower than that of the NYCA, and its IRM can be no higher than that Area's minimum requirement. In addition, EOPs are not represented in Outside World Area models.

Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within those Areas that may limit emergency assistance into the NYCA. This recognition is considered either explicitly, or through direct multi-area modeling providing there is adequate data available to accurately model transmission interfaces and load areas within these Outside World Areas. For this study, two Outside World Areas – New England and the PJM Interconnection – are each represented as multi-areas, i.e., 13 zones for New England and four zones for the PJM Interconnection. Such granularity better captures the impacts of transmission constraints within these areas, particularly on their ability to provide emergency assistance to the NYCA.

For the 2012 IRM Study, there is a projected increase in transfer capability between Ontario and New York's Zone A. This increase – 400 MW into NY and 300 MW into Ontario – is a result of the reinstatement of previously inoperable ties along with transmission improvements within Ontario. These changes are summarized in Table A-8.

Base case assumptions considered the full capacity of transfer capability from external Control Areas (adjusted for grandfathered contracts) in determining the level of external emergency assistance.

Updated Outside World Area load, capacity, and transmission representations in the 2012 IRM Study results in an IRM increase from the 2011 IRM Study by 0.1%.

Environmental Initiatives

Several state and federal environmental regulations will affect generation resources in New York State over the next decade. The only regulation that could possibly affect generation operations in the 2012 Capability Year is the newly enacted (July 2011) Cross State Air Pollution Rule (CSAPR). As a result of CSAPR, affected generators will need one allowance for each ton of SO_2 or NO_x emitted in a year. Overall, 167 generating units representing 23,275 MW of capacity are affected in New York State. The first reduction starts in 2012 with additional reductions required in 2014. A NYISO analysis examined multiple scenarios: all showed that the NYCA can operate reliably with the program in 2012 (phase one) with no effect on IRM requirements.

Compliance actions for the second phase that begins in 2014 will likely include emission control retrofits, fuel switching, and new clean efficient generation. The NYISO analysis indicates that CSAPR Phase 1 will not result in any immediate reliability impacts However, Phase 2, coupled with the forecasted impacts of the four programs discussed in the Appendix (NOx RACT, BART, MACT, and BTA), and the current economic realities (low capacity payments and less expensive natural gas) could lead to plant retirements potentially affecting reliability and IRM requirements in New York as early as 2014.

Data Base Quality Assurance Reviews

It is critical that the data base used for IRM studies undergo sufficient review in order to verify its accuracy. To accomplish this objective, this year the NYSRC significantly improved its process for reviewing the accuracy of the study's data base, while continuing to respect confidentiality issues.

The NYISO, General Electric (GE), and the New York Transmission Owners (TOs) conducted independent data quality assurance reviews after the base case assumptions were developed and prior to preparation of the final base case. Masked and encrypted input data was provided by the NYISO to the transmission owners for their reviews. The NYISO, GE, and TO reviews found several minor data errors, none of which affected IRM requirements in the preliminary base case. The data found to be in error by these reviews were corrected before being used in the final base case studies. A summary of these quality assurance reviews is shown in Appendix __.

COMPARISON WITH 2011 IRM STUDY RESULTS

The results of this 2012 IRM Study show that the base case IRM result represents a 0.6% increase from the 2011 IRM Study base case value. Table 1 compares the estimated IRM impacts of updating several key study assumptions and revising models from those used in the 2011 Study. The estimated percent IRM change for each parameter in Table 1 was calculated from the results of a parametric analysis in which a series of IRM studies were conducted to test the IRM impact of individual parameters. The results of this analysis were normalized such that the net sum of the -/+ % parameter changes totals the 0.6 % IRM increase from the 2011 Study. Table 1 also summarizes the reason for the IRM change for each study parameter from the 2011 Study.

The principal drivers shown in Table 1 that increased the required IRM from the 2011 IRM base case are: increased wind capacity, updated purchases and sales assumptions, and updated generating unit EFORs, which together, increased the 2011 IRM by 1.3%.

The parameters in Table 1 are discussed under *Models and Key Input Assumptions*. A more detailed description of these changes and their IRM impacts can be found in Appendix C.

Table 1: Parametric IRM Impact Comparison – 2012 IRM Study vs. 2011 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)	Reasons for IRM Changes
2011 IRM Study – Base Case IRM		15.5	
2012 Updated Parameters that Increase the IRM:			
New Wind Capacity (337 MW)	+0.5		Wind generator performance has low availability.
Updated Purchases and Sales	+0.4		Loss of sales contracts resulted in poor performing units remaining in NY.
Updated Generating Unit EFORs	+0.4		FOR increases in Downstate units higher relative to Upstate units.
Updated Cable Outage Rates	+0.1		Increase in cable FORs due to recent extended outage.
Updated Outside World Model	+0.1		Higher New England load growth relative to capacity increase results in reduced emergency assistance available to NYCA.
Updated EDRP Capacity	0		
Updated Maintenance	0		
New Solar Capacity	0		
Updated Load Forecast	0		
Total IRM Increase	**+1.5**		
2012 Updated Parameters that Decrease the IRM:			
Revised SCR model	-0.3		Improved methodology of assessing performance of SCR resources.
New Generating Capacity	-0.2		New generating capacity has higher availability relative to existing fleet.
Updated Load Forecast Uncertainty Model	-0.2		Recent historical data shows less load uncertainty in Zones J and K.
Updated Non-SCR/EDRP EOPs	-0.1		Increase in EOP capabilities in Downstate relative to Upstate.
Retirements	-0.1		Retirement of poorer performing generating units.
Updated Existing Generating Unit Capacities	0		
Total IRM Decrease	**-0.9**		
Net Change From 2011 Study		**+0.6**	
2012 IRM Study – Final Base Case IRM		**16.1**	

SENSITIVITY CASE STUDY RESULTS

Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from the base case will, of course, yield different results. Table 2 shows IRM requirement results and related NYC and LI locational capacities for three groups of selected sensitivity cases. Many of these sensitivity case results are important considerations when the NYSRC Executive Committee develops the Final NYCA IRM for 2012. A complete summary of all sensitivity case results is shown in Appendix B, Table B-2. Table B-2 also includes a description and explanation of each sensitivity case. A preliminary base case was used as the basis for developing the sensitivity case values in Table 2. This table reflects adjustments made to the preliminary base case sensitivity study results to reflect the final base case IRM. Further, there was no attempt to develop sensitivity results utilizing the Tan 45 "inflection point" method.

Table 2: Sensitivity Cases
NYCA 2012 IRM and Related NYC and LI Locational Capacity Impacts

Case	Case Description	IRM (%)	% Change From Base Case	NYC LCR (%)	LI LCR (%)
0	Base Case	16.1	--	84	99
2012 IRM Impacts of Major MARS Parameters					
1	NYCA isolated	24.7	+8.6	90	105
2	No internal NYCA transmission constraints	13.8	-2.3	N/A	N/A
3	No load forecast uncertainty	8.8	-8.8	79	93
4	No wind capacity (1,648 MW)	11.4	-4.7	84	99
5	No EDRPs	16.3	+0.2	84	99
6	No SCRs and EDRPs	15.5	-0.6	84	101
2012 IRM Impacts of Base Case Assumption and Model Changes					
7	Higher Outside World reserve margins	11.9	-4.2	81	96
8	Lower Outside World reserve margins	22.6	+6.5	89	104
9	Higher EFORd's	18.7	+2.6	86	101
10	Lower EFORd's	13.6	-2.5	81	101
11	Alternate load shape model	13.7	-2.4	82	97
12	Alternate wind shape model				
13	Use of a new EFORd model now under development	15.1	1.0	83	98
14	Lower SCR use modeled				
15	Retire Indian Point Units 2 and 3	21.6	+5.5	92	107
16	300 MW wheel from Quebec to New England	16.2	+0.1	84	99
17	One in two Con Edison load forecast				
18	Updated PJM representation				

NYISO IMPLEMENTATION OF NYCA CAPACITY REQUIREMENTS

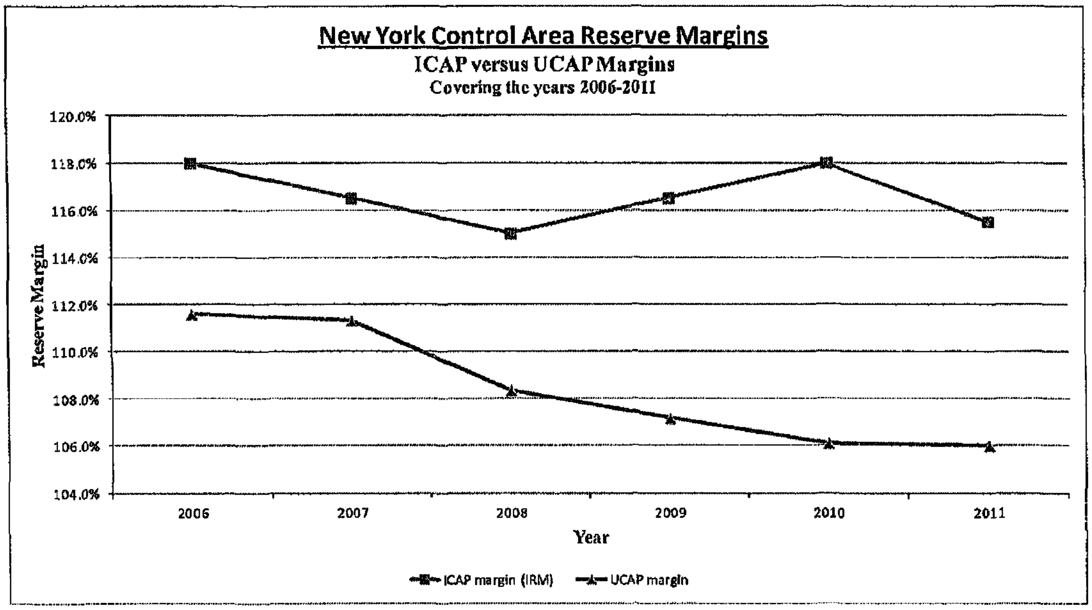
NYISO Translation of NYCA ICAP Requirements to UCAP Requirements

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity (UCAP). To maintain consistency between the rating of a unit translated to UCAP and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the summer and winter capability periods.

Additionally, any LCRs in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures compliance with NYSRC Resource Adequacy Rule A-R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

The increase in wind resources increases the IRM because wind capacity has a much lower peak period capacity factor than traditional resources. On the other hand, there is a negligible impact on the need for UCAP. Figure 3 below illustrates that UCAP reserve margins have steadily decreased over the 2006-2011 period, despite variations of UCAP requirements. This indicates a lower burden on New York loads over time. Appendix C offers a more detailed explanation.

Figure 3: NYCA Reserve Margins



NYISO Implementation of a Spot Market Auction based on a Demand Curves

Effective June 1, 2003 the NYISO replaced its monthly Capacity Deficiency Auction with a monthly Spot Market Auction based on three FERC-approved Demand Curves. Demand Curves are developed for Zone J (New York City), Zone K (Long Island), and the NYCA. The existence of Demand Curves does not impact the determination of IRM requirements by the NYSRC.

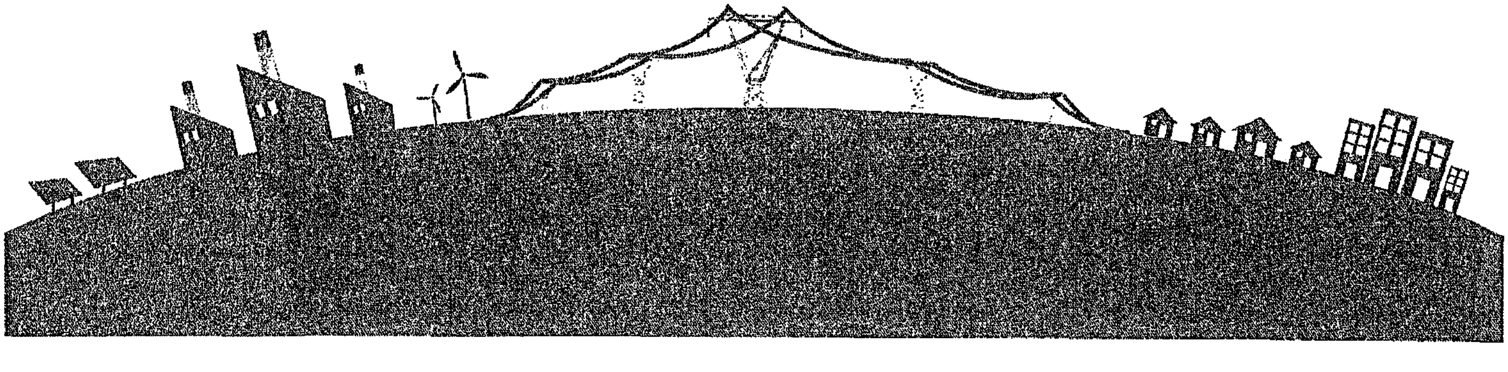
Attachment 17

COMPETE

Electricity Competition Drives Innovation and Consumer Benefits

Regulation and Oversight of the Electric Power Industry

September 14, 2010



Foreword

Over the last two decades, the electric power industry has been restructured to replace government-mandated price regulation with effective market competition, similar to the path toward greater competition taken in other important industries such as trucking, airlines, telecommunications and natural gas. Technological advances allowed the introduction of competitive forces into formerly monopoly-protected industries with price regulation. With the introduction of competition, regulatory regimes were restructured to promote market outcomes while retaining regulatory oversight to protect consumers.

In every instance of industry restructuring, various interests raised concerns about the reforms. But competitive forces and regulatory reform ultimately proved crucial to the innovation and consumer benefits that resulted. Consumers now have telecommunications equipment and services unimaginable 30 years ago, airline service that is affordable to most Americans, a trucking industry that is able to operate efficiently and responsively to business needs, and affordable natural gas supplies delivered by an interstate pipeline system that is the envy of the world. Without competition-driven innovations in these industries, consumers would be worse off today.

Restructuring of the electric power industry is following a similar path. Where competitive forces can be relied on, the nature and degree of regulation has been reformed to capture the benefits of competition. In competitive electricity markets, new, more efficient, generation technologies are being developed, creative product and service offerings are emerging, and innovative demand response services are springing up that save consumers money and give them more control over their electricity purchases. But some interest groups cited the recent meltdown of the financial services industry to raise concerns about competitive electricity markets. However, as this paper shows, substantial and comprehensive regulatory safeguards remain in place at the state and federal levels to ensure that consumers' lights stay on and prices remain reasonable. Despite the emergence of competitive forces that are driving innovation and economic and environmental benefits for consumers, the electric power industry remains among the most heavily regulated in America.

This paper details the substantial regulatory safeguards in place at the federal and state levels to ensure a reliable and efficient supply of electricity while competitive forces grow and provide the innovation that will further lower costs and provide new services for consumers.

The Honorable Federico Pena
Co-Chairman, COMPETE Coalition
Former Secretary, U.S. Department of Energy; Former Secretary, U.S. Department of Transportation

The Honorable Don Nickles
Co-Chairman, COMPETE Coalition
Former U.S. Senator

Executive Summary

The recent crisis in the financial markets has been seized upon by certain interests who argue that markets in the electric power industry are prone to similar risks. This paper addresses how the organized competitive electricity markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are often described erroneously as "deregulated" and how there is no corollary with the crisis in financial markets. While the electric industry has undergone restructuring to promote competition, regulation and oversight at the federal and state levels are as strong or stronger now as they ever were before restructuring.

Regulation in wholesale markets. Federal regulation ensures that rates for wholesale electricity sales and transmission service in interstate commerce are "just and reasonable."

Regulation in retail markets. Services in retail markets, where traditional utilities and other service providers sell energy and other services to end-use consumers, are regulated by state public utility commissions.

Reliability and adequate resources. Oversight to ensure adequate resources and reliable system operations at both the federal and state levels is detailed, extensive and comprehensive.

Financial security and transparency. Federal and state regulators have broad authority to ensure the financial security of electric utilities, and have adopted policies requiring prior approval and transparency regarding the asset and other financial dealings of utilities. The financial risk management activities of electricity market participants are addressed by new requirements under the recent financial regulatory reform law. New reporting and clearing requirements as well as standards of conduct will provide additional safeguards from financial harm.

Additional oversight. In addition to comprehensive oversight by FERC and state public utility commissions, the behavior of electric utilities is subject to review by other government authorities, such as the Federal Trade Commission, the Department of Justice, and the Commodity Futures Trading Commission.

The clear rules, transparency, and consistent oversight that result from the laws, regulations and policies described in this paper help assure that the systemic risk and collapse as occurred in the financial sector will not occur in the competitive electricity markets overseen by federal and state regulators.

Regulation and Oversight of the Electric Power Industry

The recent crisis in the financial markets has been attributed in some measure to "deregulation," as opposed to ineffective regulation and oversight. Some have seized upon this to argue that markets in the electric power industry are prone to the same problem. As this paper demonstrates, there is no corollary with the organized competitive electricity markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), which often are described erroneously as "deregulated."[1] While the electric industry has undergone restructuring over the last decade to introduce competitive forces, and the nature of its regulation and oversight has evolved, regulation and oversight remain as strong or stronger now as they ever were before restructuring.

Competitive wholesale electricity markets, and the electricity industry in general, remain among the most regulated markets and industries in the United States. For example:

- Prices charged by generators, competitive energy suppliers and utilities are in accordance with detailed regulatory policies to ensure participants cannot exercise market power.
- Wholesale markets administered by ISOs and RTOs are closely overseen by independent market monitors.
- Substantial penalties are assessed for violations of laws, rules and regulations.
- Regulators ensure there are adequate generation resources in place to meet demand, and those resources stay in place and operate regardless of financial conditions.
- The entire bulk power system is subject to comprehensive and strict reliability regulation.
- Utilities may not merge or acquire or dispose of assets without prior regulatory approval.
- Financial transparency is required.

Introduction: the Electric Power Industry Is Not 'Deregulated'

The electric power industry is regulated under strict standards at multiple levels – federal, state and sometimes local. At the federal level, the 1935 Federal Power Act requires the independent and bipartisan Federal Energy Regulatory Commission (FERC) to regulate interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances and acquisitions. In addition, FERC is responsible for setting and enforcing strict rules for ensuring reliability and cyber security that apply to all users of the nation's transmission grid.

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[1] "[T]he phrase "deregulation" is a simplistic characterization of a much more complex process that involved the relaxation of government controls over prices and entry in some industries, industry restructuring and privatization to facilitate competition . . ." Paul Joskow, *Market Imperfections Versus Regulatory Imperfections*, June 2010 at 1, http://econ-www.mit.edu/files/5619

FERC's authority under the Federal Power Act to protect consumers and ensure reliability was substantially strengthened by the Energy Policy Act of 2005. FERC is now charged with strict policing against market manipulation and rule violations, and may impose fines of up to $1 million per day, per violation.

State utility commissions perform regulatory roles similar to FERC's in regulating sales of electricity at retail to end-use customers, as well as ensuring financial stability and reliability.

Restructuring is not Deregulation

Electric industry restructuring occurred in response to the poor performance of traditional monopoly cost-based regulation. Traditional monopoly regulation, adopted in the early 20th Century, was based on the notion that electricity generation, transmission and distribution were natural monopolies requiring strict government price controls to protect consumers from monopoly abuse. With vertical integration and economies of scale, it was seen as more efficient for one regulated utility to supply the entire market. Under this regulatory model, utilities were given exclusive monopoly-protected service areas and the prices paid by consumers, known as "ratepayers," were regulated to allow recovery of costs plus a reasonable return or profit.

By the 1990s, technological advances resulting in efficient smaller scale generation and long distance transmission led many economists to argue that generation was no longer a natural monopoly, and they urged competitive reforms to allow competing suppliers to sell electricity over common transmission and distribution wires, which would remain cost-regulated monopoly businesses. This change in thinking came during a period of high prices, large cost overruns and inefficient development of excess capacity by utilities. The monopoly regulatory structure encouraged overinvestment and did not provide the right incentives and flexibility to adjust to changing economic conditions and adequately protect consumers. In the face of fundamental and unavoidable technological and economic change, cost-of-service ratemaking was seen as ineffective and inefficient, and as having imposed huge unnecessary costs on consumers. As a result, federal policymakers and state policymakers in many regions of the country undertook to restructure the electric industry to promote competition and markets as an alternative to government-determined rate regulation.

The driving idea behind electricity restructuring was to allow well-structured and highly-regulated competitive markets to determine the value of electricity and to reward firms based on their performance, just as markets do for other goods and services in our society.[2] To accomplish this, restructuring included developing regional wholesale power markets and allowing end-use consumers in retail markets a choice of generation service providers.

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[2] "No markets in modern developed economies are completely 'unregulated' by government-created institutions in any meaningful sense. Markets in all modern developed market economies operate within a basic set of governance institutions . . ." Joskow, *id.*, at 4.

Today, competitive electricity markets administered by ISOs and RTOs serve two-thirds of the U.S. population and a similar proportion of Gross Domestic Product (GDP), and facilitate well-structured competition among an increasing number of diverse suppliers selling generation and other services.

Restructuring has effectively shifted the risk of poor business decisions away from consumers to investors, where it belongs. Under the old monopoly protected model, investment was made "in ratebase," meaning that customers captive to their monopoly service provider bore the risk of poor investment decisions and inefficient overinvestment. With restructuring, the risk of poor and inefficient decisions is borne by investors. This is a significant consumer benefit.

While the nature of regulation and oversight of the electric power industry has changed over the last decade or so, it is a misnomer to term it "deregulation." Strict oversight is still required by various statutes, and regulation remains strong, focused and comprehensive. In fact, in the restructured markets, the regulatory oversight is arguably stronger than it was under the monopoly-protected regulatory model.

This paper addresses the strict oversight and enforceable rules in competitive electricity markets administered by ISOs and RTOs that are critical to assuring consumers benefit from a strong, stable electric power industry.

Wholesale Electricity Markets and FERC Regulation

The Federal Power Act requires FERC to ensure that rates for wholesale electricity sales and transmission services in interstate commerce are "just and reasonable." It is a misnomer to term those services "deregulated." FERC has adapted its policies to apply the appropriate type of regulatory oversight required by market conditions.

Pricing Policies

Because transmission is still considered to have natural monopoly characteristics, prices and other terms of interstate transmission service are regulated on a traditional cost-of-service basis by the FERC. For generation services, the FERC uses both a cost-of-service basis and a market basis for determining appropriate prices, the choice of which depends on whether or not individual sellers are able to exercise market power. The ability to exercise market power means a seller can influence market prices to its financial benefit. For sellers that can exercise market power, the FERC strictly regulates their prices for wholesale generation services on a traditional cost-of-service basis. But if a seller can demonstrate that it cannot exercise market power in the market or markets where it makes sales, FERC allows it to charge prices for electricity that are disciplined by market forces.[3]

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[3] Order No. 697, *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 F.E.R.C. ¶ 61,295 at PP 62, 399, 408 and 440 (2007).

To qualify for "market-based" pricing authority, a seller must present data and analyses showing that: (1) it does not own or control more than 20% of the generation capacity in the relevant market; (2) it is not a "pivotal supplier" (*i.e.*, market demand can be fully met without the seller's supply); (3) an open access transmission tariff, which provides fair access to the transmission grid for all sellers, is on file for any transmission facilities controlled by it or its affiliates; and (4) it cannot erect barriers to entry by other sellers.[4] In addition, sellers with market-based pricing authority must also re-qualify every three years by filing updated data and analyses to demonstrate that they are still unable to exercise market power.[5]

Market monitoring

Once a seller has FERC's approval to charge market-based prices, it is then subject to restrictions on its behavior and a vigorous monitoring and enforcement program at the FERC. Federal courts require this. One very basic part of FERC's monitoring program is ensuring that sellers with market-based pricing do not gain over time the ability to exercise market power due to changes in their assets or in market conditions. Sellers with market-based pricing must report within 30 days any change in their assets or any other characteristic the commission relied upon in approving market-based pricing. Such changes typically relate to control of additional generation capacity of 100 MW or more, new affiliations with entities that control generation or inputs to electricity production, or additional control of inputs to electricity production such as sites for generation facilities.[6]

FERC closely monitors the behavior of sellers in wholesale electricity markets. The market oversight division of FERC's enforcement office monitors in real time the conditions and prices in natural gas and electric power markets as well as related energy and financial markets. This monitoring contributes to FERC's understanding of the markets' underlying conditions and trends, and thereby helps in understanding market participant behavior and identifying potential for market abuse.

In addition to this active market oversight, FERC operates a "hotline" allowing confidential submittal of market abuse concerns to FERC's enforcement office. Another important check against questionable behavior are reports from the independent monitors for the organized markets administered by RTOs and ISOs. One of the functions assigned to the market monitors by the FERC is identifying and notifying the FERC enforcement staff of behavior that may require investigation, including suspected tariff and rules violations, and suspected market manipulation.[7]

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[4] *See* 18 C.F.R. § 35.37 (c)-(e). *See also* Order No. 697, *id.*, at PP 12-22.

[5] *See* 18 C.F.R. § 35.37(a)(1).

[6] *See* 18 C.F.R. § 35.42.

[7] Order No. 719, *Wholesale Competition In Regions With Organized Electric Markets*, 125 F.E.R.C. ¶ 61,071 at P 354 (2008). FERC must enforce a statutory prohibition of energy market manipulation, which is defined as the direct or indirect use of "any manipulative or deceptive (continued...)

FERC employs a number of additional monitoring tools to discover and understand market behavior. One of those tools is the Electric Quarterly Report (EQR), in which each seller reports the terms of all wholesale sales of electricity and transmission service. Every three months, sellers must report details about each transaction, including the names of the seller and buyer, type of product, duration of the transaction, points of receipt and delivery on the grid, quantity, price or rate and the total charges in the transaction.[8]

FERC's enforcement office undertakes a regular program of audits to assure compliance with FERC rules and accounting requirements. If a company is not in compliance, the commission's auditors recommend corrective actions and suggest preventive measures to avoid problems in the future. FERC's approach is proactive, and the audits usually focus on compliance areas of material interest such as the Open Access Transmission Tariff or the restrictions and responsibilities of sellers with market-based rate authority. FERC staff selects possible audit candidates based on information gained from the agency's monitoring activities, analysis of information from internally developed behavior and market screens, and information from other FERC offices.

Protecting Against Conflicts of Interest

Sellers with market-based rate authority who are affiliated with traditional utilities with captive customers, *i.e.*, those customers with no choice of electricity supplier, also face restrictions on their behavior to protect against cross-subsidization and to ensure fair competition between utility affiliates and other market participants selling generation services. Market-based rate sellers must operate separately from affiliated utility personnel and may not seek or receive market information from the utility affiliate.[9] Every electricity transaction between a utility and an affiliate with market-based rates, and not otherwise subject to traditional regulation, must be approved by the FERC.[10] Utilities that operate transmission facilities are prohibited from sharing non-public transmission information with their power marketing employees and affiliates so as not to confer an unfair competitive advantage.[11]

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device or contrivance" in connection with FERC jurisdictional electric energy or transmission transactions. Federal Power Act § 222 (codified at 16 U.S.C. § 824v). *See also* 18 C.F.R. § 1c.2.

[8] *See* FERC, EQR FILINGS REQUIREMENTS GUIDE (2005), *available at* http://www.ferc.gov/docs-filing/eqr/news-help/require-guide.pdf.

[9] *See* 18 C.F.R. § 35.39.

[10] *See* 18 C.F.R § 35.44.

[11] *See* 18 C.F.R. § 358.

Enforcement

FERC can levy substantial penalties for any behavior determined to be market manipulation, or for any other violations of its tariffs or regulations. FERC has authority to impose penalties of up to $1 million per day for each violation and may impose other remedies.[12] During 2009, FERC collected more than $38 million in civil penalties and nearly $39 million in disgorged profits.[13] In an effort to provide fairness, consistency and transparency to civil penalty determinations, the commission has proposed guidelines intended to base penalties on a set of uniform objective factors that are valued and weighted similarly for similar types of violations and similar types of violators.[14] Penalties would vary according to the severity of the violation and the culpability of the violator.

In addition to imposing monetary and other sanctions, FERC can refer cases to the Department of Justice (DOJ) for criminal prosecution, for which fines and imprisonment are applicable. It should also be noted that the Commodity Futures Trading Commission (CFTC) can also levy penalties of up to $1 million per day, per violation and impose other remedies for manipulation of commodity and financial futures and options. These financial instruments can relate to energy commodities that affect electricity costs.

Additional Protections in Organized Competitive Markets (RTOs and ISOs)

The organized competitive electricity markets administered by FERC-authorized RTOs and ISOs have additional safeguards and protections in place and receive more scrutiny than transactions that occur bilaterally. RTOs and ISOs generally have markets for various spot energy products and in some cases a market for capacity resources. These markets typically have bid caps that limit prices. While the cap level and the conditions in which caps are imposed vary across the markets, bid caps protect against substantial price increases that might not be justified by market conditions.

Oversight by independent market monitors is a key protective feature of the organized RTO markets. The monitors are highly qualified, experienced professionals independent of the market and market participants. Each monitor employs an interdisciplinary team of economists, electrical engineers and software developers.[15] The monitors have access to cost, bid and price data, as well as a host of data on the operations of the markets and the facilities in those markets.

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[12] *See* Federal Power Act § 316A(b) (codified at 16 U.S.C. § 825o-1(b)).

[13] FERC, 2009 REPORT ON ENFORCEMENT 3 (2009), *available at* http://www.ferc.gov/legal/staff-reports/12-17-09-enforcement.pdf.

[14] *Enforcement of Statutes, Orders, Rules and Regulations,* 130 F.E.R.C. ¶ 61,220 (2010). FERC suspended the Policy Statement issuing the guidelines to receive public comments. 131 F.E.R.C. ¶ 61,040 (2010).

[15] Dr. David Patton, Market Monitor for the Midwest ISO, ISO New England, and the New York ISO, *Competitive Electricity Markets and Market Monitoring,* Presentation to Market Monitors (continued...)

As discussed, one of the functions of the monitors is to identify and notify the FERC enforcement staff of instances of behavior that may require investigation, including rule violations. To perform this function, market behavior, such as bidding and generation scheduling, is monitored in real time. As one market monitor observed, "(m)arket monitors have the legal authority to gather the information we need from the market participants. If investigations indicate anticompetitive conduct or gaming that cannot be addressed by our market power mitigation measures and sanctions, the conduct is referred to FERC for enforcement."[16] Market participants know their behavior is being closely scrutinized at all times, providing a strong incentive to operate within the rules of the market.

FERC has assigned the monitors responsibility to evaluate the market rules and market design, and review the performance of the market and recommend changes in regard to both of these functions where needed.[17] To meet this mandate, the monitors perform extensive analysis of every aspect of market operations and present periodic public reports for each market. Generally, the monitors assess whether the markets have an efficient daily commitment of generation, dispatch the lowest-cost resources to satisfy demand without overloading the transmission network, and provide transparent economic signals to guide operations and investment decisions. To date, the monitors "have found that the wholesale electricity markets have been very competitive and delivered the following specific benefits: lower overall supply costs; higher availability and ratings for existing power plants; and more accurate price signals to guide investments."[18]

The following are factors the monitors generally address in the evaluations:

- Market structure and performance, including market size, concentration, prices, price volatility, mark-up over costs and other measures.
- Market performance, including prices, price volatility, price mark-up over costs, and pricing in congested areas and during shortage conditions.
- Participant conduct, including evidence of physical and economic withholding.
- Whether the market results in net revenues sufficient to attract new entry (and which types of generation).
- Resources, including resource margins, and generator availability and outages.
- Transactions and coordination with adjacent markets.

Briefing Sponsored By the COMPETE Coalition, at 4 (Apr. 20, 2010), *available at* http://competecoalition.com/files/patton.pdf.

[16] Dr. David Patton, Market Monitor for the Midwest ISO, ISO New England, and the New York ISO, *Market Monitors Explain Competitive Market Outcomes in Organized Electricity Markets* (Apr. 21, 2010), http://www.competecoalition.com/blog/2010/04/market-monitors-explain-competitive-outcomes-in-organized-electricity-markets.

[17] Order No. 719, *op cit.,* at P 354.

[18] Patton, April 20, 2010, *op cit.,* at 3.

- Transmission congestion and costs.
- Price convergence between day-ahead and real-time markets.
- Price convergence with adjacent markets.
- Demand response performance.
- Accuracy of load forecasts.

In the most recent annual monitor reports available,[19] each of the markets was found to have performed competitively[20] and none was found to have produced sufficient net revenues to sellers to support the cost of new generation. This is evidence that prices are just and reasonable and that consumers are not overcharged for generation services in ISOs and RTOs.

An important additional protection in organized electricity markets is strict creditworthiness requirements. Each RTO or ISO requires market participants to meet such requirements. Barring financially weak participants can help keep costs down by preventing defaults, and provides the confidence needed to attract a broad array of participants in the market. To further promote confidence in the markets FERC has proposed specific requirements regarding credit policies.[21] Among other things, FERC proposes to require that all organized market tariffs include provisions that limit to $50 million the unsecured credit extended to any participant, limit settlement periods to seven days, allow the market administrator to require additional collateral under certain conditions, and eliminate unsecured credit for certain hedging instruments.

Retail Markets and State Regulation

Retail markets are where traditional utilities and other service providers sell energy and other services to end-user consumers, such as homeowners, businesses, units of government, schools, hospitals, manufacturers, and others. Generally, services and other aspects of these markets are regulated by state public utility commissions.[22] In states that do not allow retail

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[19] See monitors' reports for 2009 for PJM, New York ISO, Southwest Power Pool, California ISO, ISO New England, and Midwest ISO.

[20] There was one exception. The results of the PJM Regulation market were not found to be competitive. This was not the result of market participant behavior, but instead due to a change in the market rules that resulted in prices above competitive levels. Otherwise, Dr. Joseph Bowring, the PJM monitor found that "(u)nits that were on the margin and set the price in the energy market offered at price equal to their short-run marginal cost." Dr. Joseph Bowring, Independent Market Monitor For PJM Interconnection, at COMPETE "Meet the Market Monitors" Event (Apr. 20, 2010), http://www.competecoalition.com/blog/2010/04/market-monitors-explain-competitive-outcomes-in-organized-electricity-markets.

[21] Notice of Proposed Rulemaking, *Credit Reforms in Organized Wholesale Electric Markets,* 130 F.E.R.C. ¶ 61,055 (2010).

[22] The exceptions are localities where service is provided by municipal government utilities and rural cooperatives. In those cases, rates and other aspects of retail electricity service are (continued...)

competition, i.e., where consumers have no choice but to purchase electricity from a franchised monopoly-protected supplier, service is priced on a traditional cost-of-service basis. Utilities are allowed to recover their costs plus what the regulator determines to be a reasonable rate of return, or profit.

In states that allow retail competition, consumers may choose their provider of electric energy, i.e., the generation service, but the local utility still provides the delivery service over its transmission and distribution wires. The wires part of the service is still regulated on a traditional monopoly-protected, cost-of-service basis, while energy service providers are allowed to charge market-determined prices disciplined by competitive market forces.

Where retail competition is allowed, state commissions impose a number of safeguards to protect consumers. Perhaps the most important safeguard is imposing Provider-of-Last-Resort (POLR) obligations on incumbent utilities. If a consumer does not elect to purchase from a competitive supplier, or an alternative supplier leaves the market, the incumbent utility is required to serve that consumer at a rate that reflects the cost of procuring the power.[23] Some states require that the incumbent utility purchase the supply to meet its POLR obligations in a competitive procurement process overseen by the state commission.

State commissions also oversee competitive suppliers, which generally must be licensed or certified by the state commission after showing they meet specific managerial, technical and financial requirements.[24] Most states require periodic updates or continuing certification requirements upon competitive suppliers. Moreover, their sales and marketing activities and other behavior are often monitored and regulated by the states – especially as it relates to residential and smaller commercial customers.[25] These regulations may include reporting requirements in the areas of customer complaints, customer service calls, revenue reports, fuel mix disclosures, and certain other compliance matters.

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generally overseen by municipal governments and cooperative boards, respectively. The discussion in this paper describes regulatory oversight by public utility commissions.

[23] *See, e.g.*, 220 ILL. COMP. STAT. 5/16-103(c)-(d); MD. CODE ANN., PUB. UTIL. COS. § 7-510(c)(2), (c)(3)(ii)(2); N.Y. State Pub. Serv. Comm'n, *In the Matter of Competitive Opportunities Regarding Electric Service,* Op. No. 97-15 at 5, 12-13 (1997); 66 PA. CONS. STAT. ANN. § 2807(e)(3.1); TEX. UTIL. CODE ANN. § 39.106(a)-(b).

[24] In addition, the New York Public Service Commission Uniform Business Practices for competitive suppliers contain a range of consumer protections with which the supplier must comply or face suspension or other sanctions by the commission. N.Y. State Pub. Serv. Comm'n, 98-M-1343, *Uniform Business Practices* § 2(D)(4)-(5) (2009), *available at* http://www.dps.state.ny.us/index.html (follow "electric" hyperlink; then follow "uniform business practices" hyperlink).

[25] *See, e.g.*, 220 ILL. COMP. STAT. 5/16-111.5(c), 5/16-115(d)(4), (f), 5/16-120(a); MD. CODE ANN., PUB. UTIL. COS. § 7-514(a)(2); 66 PA. CONS. STAT. ANN. § 2811(a); TEX. UTIL. CODE ANN. § 17.051.

In order to protect consumers from cross-subsidizing investors and shareholders, state commissions employ various means to scrutinize and restrict utility dealings with affiliates. Some of the ways commissions may guard against cross-subsidization are:

- Requiring prior approval of all contracts with affiliates. [26]
- Requiring annual reporting, and conducting periodic audits of transactions with affiliates.[27]
- Restricting guarantees of an affiliate's debt or prohibiting loans to an affiliate on terms more favorable than commercial terms.[28]
- Seeking treble damages for payments that benefit an affiliate.[29]
- Requiring non-discriminatory information sharing or use of a utility's wires to its affiliate's competitors.[30]

Reliability and Adequate Resources

Adequate resources and reliable system operations are fundamental to the high quality electric service that consumers and businesses depend on. Keeping the lights on has always been important, but power quality is an increasingly high priority for our digital economy. Regulatory oversight of these factors at both the federal and state levels is detailed, extensive and comprehensive.

Resource Adequacy

Regulatory commissions use a variety of means to ensure there are enough generation resources to meet demand. Some state commissions adopt standards for capacity or reserve margin requirements that must be met by each utility to meet forecasted load, and some set specific multi-year plans to procure sufficient resources.[31] Some apply those same requirements to competitive suppliers. Other commissions conduct periodic audits to ensure adequate reserve

[26] This is the case in Illinois. 220 ILL. COMP. STAT. 5/7-101(3).

[27] This is the case in California. CAL. PUB. UTIL. CODE §§ 587, 797.

[28] For example, Maryland law provides such a prohibition. MD. CODE ANN., PUB. UTIL. COS. § 6-101(a)(2)(iii).

[29] The California commission may seek treble damages if it find that a utility "made an imprudent payment to, or received a less than reasonable payment from" an affiliate if made or received for the purpose of benefiting the affiliate. CAL. PUB. UTIL. CODE § 798(a).

[30] Illinois law requires this. 220 ILL. COMP. STAT. 5/16-121.

[31] For example, in Illinois utilities must file for approval by the state commission a five-year procurement plan that includes hourly load analyses and a plan for meeting load requirements. 220 ILL. COMP. STAT. 5/16-111.5(a).

margins.[32] Commissions have authority to order improvements needed for reliability, and utilities must obtain prior approval from state commissions before constructing electrical facilities.[33]

In the organized wholesale markets administered by RTOs and ISOs, FERC oversight provides an additional level of assurance that adequate resources will be in place to assure just and reasonable prices in wholesale markets. The commission reviews overall capacity requirements for each market and the responsibility for meeting those requirements assigned to each load serving entity. Adequate generation capacity helps mitigate price increases in the wholesale electricity markets under FERC's jurisdiction.

Reliable Operations

In addition to an adequate supply of resources, the grid must be operated reliably to keep the lights on and the air conditioning humming. Reliable grid operation involves requiring participants to act in a coordinated way over a highly complex network, and energy must be generated at the same time it is consumed to keep the system balanced. Accordingly, all participants must observe strict and comprehensive operational standards and act appropriately.

The 2003 Northeast Blackout demonstrated the need for strong enforceable standards and rules to ensure reliable operations of the nation's electricity grid. In the Energy Policy Act of 2005, Congress required all entities that use the transmission system to comply with a detailed system of mandatory reliability standards overseen by FERC for the reliable operation of the grid.[34] Based on this authority, FERC certified an independent organization, the North American Electric Reliability Corporation (NERC), to oversee the development and implementation of reliability standards. To date, the commission has approved more than 1,000 pages of reliability standards that address, among other things, resource and demand balancing, scheduling, operations, critical infrastructure protection, emergency preparedness, and transmission planning.[35] All grid users, from the largest generation and transmission owners to the smallest load-serving entity, must register with one of several regional entities, which are responsible for monitoring to ensure that all registered users comply with the reliability standards. Each standard is written so it is clear which entities (generators, transmission providers, load-serving entity, etc.) are responsible for compliance.

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[32] *See, e.g.*, 220 ILL. COMP. STAT. 5/18-102; N.Y. PUB. SERV. LAW § 66(19); 66 PA. CONS. STAT. ANN. § 516.

[33] CAL. PUB. UTIL. CODE §§ 762, 1003, 1006; 220 ILL. COMP. STAT. 5/8-406; MD. CODE ANN., PUB. UTIL. COS. § 7-207(b)(1); N.Y. PUB. SERV. LAW §§ 68, 72; 66 PA. CONS. STAT. ANN. §§ 518-19, 1505(a); TEX. UTIL. CODE ANN. § 38.071(1)(A).

[34] *See* Federal Power Act § 215, as added by Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 594, 941-46 (codified at 16 U.S.C. § 824o).

[35] North American Electric Reliability Corp., *Reliability Standards*, http://www.nerc.com/page.php?cid=2|20

Violations of the reliability standards are reported to FERC, which can impose fines of up to $1 million per day, per violation. In one recent case, Florida Power & Light Co., in a settlement with the FERC, agreed to pay a $25 million civil penalty and take specific reliability enhancement measures in connection with a 2008 blackout on its system.[36] The regional entity for Florida also agreed to pay a $350,000 penalty for violating reliability standards that contributed to the blackout.[37] This is just one example of how FERC's authority ensures strict compliance with reliability standards.

Even with the resource adequacy requirements and reliability rules, there occasionally may arise circumstances that threaten reliability. To remedy such situations, FERC has authority under section 202(b) of the Federal Power Act to order physical interconnections or sales of electric energy when necessary or appropriate in the public interest. For example, in 1999 FERC ordered an interconnection of utility facilities for the utility to meet its existing and future needs.[38]

State regulatory commissions also have extensive authority and programs to assure reliability. While specific authorities and practices vary, states generally may set and enforce reliability benchmarks, require periodic reliability performance reporting, establish, monitor and enforce inspection and maintenance standards, review customer service reliability complaints, and monitor and investigate major reliability events.

Assurance of Service to Consumers

In light of these and other federal and state regulatory authorities and practices, there is little likelihood that financial problems of one market participant would spread systemically and impact the service reliability of other participants the way the financial crisis spread through the credit markets and impacted the performance of many financial and investment firms. The resource adequacy requirements of the states and FERC assure that there are hard assets such as generators and wires facilities in place. These facilities do not disappear or move geographically with financial conditions, and history demonstrates that a company's "hard assets" will continue to operate under bankruptcy protection and continue to provide service to consumers. Operations and reliability would not be affected, and regulators would take any steps necessary to protect consumers.[39]

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[36] *Florida Blackout,* 129 F.E.R.C. ¶ 61,016 (2009).

[37] *Florida Blackout,* 130 F.E.R.C. ¶ 61,163 (2010).

[38] *Ill. Mun. Elec. Agency v. Ill. Power Co.*, 86 F.E.R.C. ¶ 61,045 (1999).

[39] For example, in May 2003, NRG, then a unit of Xcel Energy, entered bankruptcy, but its generation facilities continued to operate throughout the proceedings. In December 2003, NRG exited bankruptcy as an independent company.

Financial Security and Transparency

Federal and state regulators have broad authority to ensure the financial security of electric utilities and have adopted policies requiring prior approval and transparency regarding the financial dealings and status of public utilities.

Reviewing Mergers, Acquisitions and Debt Transactions

FERC's approval is required by law for dispositions and mergers of public utility facilities, public utility acquisitions of existing generation facilities and the securities of other public utilities, and utility holding company acquisitions of certain securities.[40] Before approving a transaction, FERC conducts a thorough review to ensure the transaction will not have an adverse impact on competition in electricity markets, public utility rates and regulation, and that the transaction will not result in cross-subsidization by ratepayers.[41] For all proposed transactions, FERC provides the opportunity for public comment and specifically addresses all comments in its final decisions. If a significant concern is raised, a public trial-type hearing may be held.

At the federal level, public utility mergers are also subject to antitrust review by the DOJ and the Federal Trade Commission (FTC). DOJ and FTC conduct their own reviews under federal antitrust law and may make findings and require conditions independent of those imposed by FERC.

State public service commissions or other state regulatory authorities have a variety of powers to review and approve public utility mergers and other transactions involving utility assets and securities.[42] Typically, utility acquisitions of assets or stock of other utilities, or the disposition of utility assets, require prior state regulatory approval or a report to a state regulatory commission. Some states also require prior approval for utilities to acquire or hold more than specific percentages of another company.[43]

With regard to public utility issuances of securities and the assumption of obligations or liabilities, state regulatory authorities typically require prior approval of such instruments with

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[40] *See* Federal Power Act § 203 (codified at 16 U.S.C. § 824b).

[41] *See* 18 C.F.R. § 33, and Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Policy Act: Policy Statement*, 77 F.E.R.C. ¶ 61,263 (1996).

[42] *See, e.g.*, CAL. PUB. UTIL. CODE §§ 851, 854(a)-(c); 220 ILL. COMP. STAT. 5/7-102(A)(a)-(h); MD. CODE ANN., PUB. UTIL. COS. §§ 5-203(a), 6-10(c)(3); N.Y. PUB. SERV. LAW §§ 69-a(1), 70(1); 66 PA. CONS. STAT. ANN. § 1102(a)(3)-(4); TEX. UTIL. CODE ANN. §§ 14.101-14.102.

[43] In Pennsylvania, for example, a public utility must obtain a certificate from the commission to acquire more than 5% of the voting stock of any corporation. 66 PA. CONS. STAT. ANN. § 1102(a)(4).

periods longer than 12 months.[44] Issuances and assumptions may be restricted to specific purposes, and criminal and civil penalties may apply for violations. If state law does not provide authority to review securities issuances and debt assumptions, then the FERC has the authority to do so for issuances or assumptions that mature in more than one year from issuance or are greater than five percent of the par value of the utility's outstanding securities.[45] The FERC must find that a security issuance or debt assumption by a public utility is for a lawful object consistent with and necessary to the utility's performance as a public utility.[46]

Protecting Against Conflicts of Interest

To protect utility customers against conflicts of interest in financial and other commercial arrangements of utilities, utility officers and directors may not serve as officers or directors of another utility, a bank, a security underwriter, or an electrical equipment supplier without FERC approval. Before approving a request for such an "interlocking directorate," FERC must find that neither public nor private interests will be adversely affected by the requested interlocking directorate.[47] FERC requires each public utility to file an annual report (Form 561) detailing which of its officers or board members also held such a position in the preceding year in the types of firms identified above. [48]

Safeguarding Transactions Related to Financial Risk Management

Electric utilities and market participants are subject to additional regulation under the financial regulatory reform legislation signed into law on July 21, 2010.[49] Utilities and generators regularly utilize financial derivative instruments to "hedge" against the risks of price fluctuations for their purchases of fuel used for generating electricity, among other commodities. By hedging financial risks, these instruments help keep costs down for consumers. The hedging activities of electric utilities and generators will be placed under the following additional safeguards following the implementation of the law:

- All financial derivative transactions will be reported to a derivatives reporting organization registered and overseen by the CFTC, or to the CFTC.

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[44] See, for example Cal. Pub. Util. Code § 818 and § 825, 220 Ill. Comp. Stat. 5/6-102(a), Md. Code Ann. Pub. Util. Cos. §§ 5-203(b)(2)(ii), 6-101(2)(ii), N.Y. Pub. Serv. Law § 69, and 66 Pa. Cons. Stat. Ann. § 1901(a) and § 1903(a).

[45] Such requests are submitted to the FERC on a standard form (Form No. 523).

[46] See Federal Power Act, § 204. FERC grants blanket approval for future issuances of securities and assumptions of liability for sellers authorized to charge market-based rates who are not public utilities and do not provide service at cost-based rates. Order No. 697, *op cit.,* at P 999.

[47] *See* Federal Power Act § 305 (codified at 16 U.S.C. § 825d).

[48] *See* 18 C.F.R. § 46.4.

[49] Dodd-Frank Wall Street Reform and Consumer Protection Act.

- Certain financial derivative transactions will have to be cleared through a clearinghouse regulated by the CFTC, and subject to margin and capital requirements.
- Business conduct standards, record keeping and disclosure requirements, and rules mitigating conflicts of interest will be imposed on certain entities involved in derivatives transactions.

These and other measures will subject the electric power industry to yet another layer of oversight and regulation, further ensuring that consumers are protected from financial harm.

Providing Transparency

FERC's requirement that the financial records of jurisdictional public utilities be kept in accordance with the FERC's comprehensive Uniform System of Accounts provides additional financial oversight and transparency. Accounts, along with detailed guidance for accounting entries, are established for capital, as well as operating expense and revenue items.[50] Most or all state regulatory commissions also require their local utilities to adhere to FERC's system.[51] The uniform accounts facilitate a high level of transparency that allows analysis of the costs and financial status of utilities across the nation by regulators, customers and other members of the public.

Finally, certain entities must regularly file financial reports with FERC and the states, and are publicly available. For example, FERC requires the following periodic filings:

- **Form 1.** This is a comprehensive annual report of financial and operating data that includes, among other things, balance sheet and operating expense and income information.
- **Form 3-Q.** This is a comprehensive quarterly report of financial and operating data that supplements the annual Form 1.[52]

State commissions generally have broad authority to require financial reports to be filed by public utilities, or to request financial information.[53] In some states such requirements are

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[50] 18 C.F.R. § 101. FERC generally waives the requirement for adhering to the Uniform System of Accounts for sellers authorized to charge market-based rates. Order No. 697, *op cit.*, at PP 984-986.

[51] See, for example, Md. Code Ann. Pub. Util. Cos. § 6-204, and 66 Pa. Cons. Stat. Ann. § 1701

[52] FERC generally waives the requirement for the Form 1 and Form 3-Q filings from sellers authorized to charge market-based rates. Order No. 697, *op cit.*, at PP 984-986.

[53] For example, the California Public Utility Commission has authority to require utilities to file monthly earning and expense reports. CAL. PUB. UTIL. CODE § 584.

backed up by explicit penalty authority for omission or falsification of required data.[54] Some state commissions are also required by statute to perform periodic audits of utilities.[55]

Additional Oversight of Utilities

In addition to comprehensive oversight by FERC and state public utility commissions, the behavior of electric utilities is subject to review by other government authorities. At the federal level, these include FTC, DOJ and CFTC. For example, in February 2010, DOJ reached a settlement with KeySpan Corporation that requires KeySpan to pay $12 million for violating the antitrust laws by entering into an agreement restraining competition in the New York City electricity capacity market.

In April 2010, the CFTC ordered San Diego Gas & Electric Co. (SDG&E) to pay a civil penalty of $80,000 for engaging in prohibited "wash" trades of NYMEX natural gas futures contracts between January 26 to February 2, 2006. SDG&E was also required to implement procedures to ensure transactions it makes in U.S. futures markets comply with market rules and the Commodity Exchange Act.

Conclusion

The U.S. electric power industry is now able to rely on competitive market forces to guide many supply and demand decisions. Where that is occurring, electricity markets are restructured and regulators have reformed the way those markets are regulated. That does not mean, however, that those markets are deregulated. At the federal and state levels, regulators still maintain comprehensive oversight to ensure that consumer prices remain reasonable, markets are not manipulated, supply will be sufficient and reliable, and financial attributes remain sound. The clear rules, transparency, and consistent oversight that result from the laws, regulations and policies set out herein will allow the full realization of the efficient resource use and innovation that competitive electricity markets can deliver to consumers.

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[54] *See, e.g.*, 220 ILL. COMP. STAT. 5/5-107; N.Y. PUB. SERV. LAW § 66(6).

[55] *See, e.g.*, 66 PA. CONS. STAT. ANN. § 516(a).

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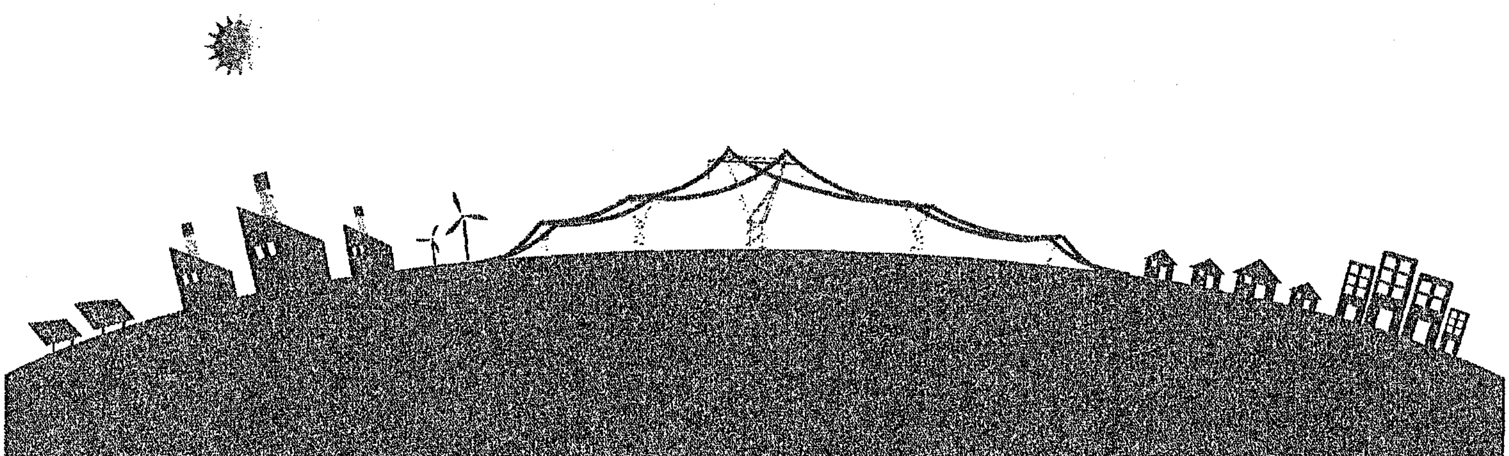

Attachment 18

Attachment 18
Residential Relative Standard Deviation by State by Time Period

State	1993-2002	2003-2012	2008-2012
DE	3%	18%	1%
MS	2%	10%	2%
NH	5%	11%	2%
AR	4%	8%	2%
US	1%	11%	2%
NJ	6%	16%	2%
IL	8%	14%	2%
NY	2%	9%	2%
FL	3%	11%	3%
ME	4%	10%	3%
AZ	5%	11%	3%
AL	2%	15%	3%
NV	13%	10%	4%
OK	3%	8%	4%
CA	5%	8%	4%
NC	1%	8%	4%
TN	4%	15%	4%
IA	2%	7%	5%
WA	9%	10%	5%
MT	7%	9%	5%
VA	2%	13%	5%
GA	1%	12%	5%
DC	3%	20%	5%
NM	3%	10%	5%
MD	3%	23%	5%
OH	2%	12%	5%
IN	2%	13%	5%
WI	6%	14%	5%
CO	1%	11%	5%
SC	1%	12%	6%
CT	4%	19%	6%
MN	2%	13%	6%
KY	1%	15%	6%
OR	9%	12%	6%
ID	9%	12%	6%
PA	2%	12%	6%
TX	4%	11%	6%
WY	5%	10%	6%
VT	9%	10%	6%
UT	4%	11%	7%
SD	2%	9%	7%
ND	2%	10%	7%
RI	6%	12%	7%
MA	6%	13%	8%
KS	1%	13%	8%
NE	2%	13%	8%
MO	1%	13%	8%
LA	4%	8%	8%
MI	2%	18%	9%
WV	1%	18%	12%

Source: U.S. Energy Information Administration analysis

Residential Price Change by State by Time Period

State	1993-2002	2003-2012	2008-2012
LA	-8%	7%	-19%
RI	-10%	24%	-17%
MA	-1%	29%	-16%
TX	1%	21%	-15%
CT	-4%	53%	-11%
ME	11%	19%	-9%
MD	-6%	66%	-7%
DC	11%	56%	-4%
NY	3%	24%	-3%
DE	-3%	58%	-3%
MS	2%	34%	-2%
FL	2%	35%	-1%
NV	45%	31%	-1%
AR	-12%	28%	0%
NJ	-9%	48%	1%
NH	-3%	34%	3%
IL	-18%	36%	3%
OK	-6%	26%	4%
US	1%	36%	5%
AL	4%	53%	9%
AZ	-14%	35%	10%
MT	25%	34%	11%
GA	-2%	43%	11%
CO	2%	40%	12%
CA	12%	27%	13%
PA	2%	34%	13%
TN	11%	54%	13%
WA	37%	35%	13%
NC	0%	30%	14%
NM	-7%	31%	14%
IA	4%	27%	14%
WI	16%	53%	15%
VA	3%	43%	16%
OR	42%	39%	16%
OH	-1%	41%	16%
MN	6%	49%	17%
IN	4%	48%	17%
SC	5%	45%	17%
KY	-1%	61%	17%
VT	30%	35%	20%
WY	17%	40%	20%
ND	1%	39%	20%
UT	-1%	44%	20%
SD	5%	34%	21%
ID	32%	36%	21%
KS	-3%	45%	26%
MO	-3%	45%	26%
NE	8%	46%	27%
MI	2%	69%	32%
WV	-1%	58%	39%

Source: U.S. Energy Information Administration analysis

Note: The red font reflects those states in the competitive group, the blue font for traditional states, and the black for hybrid States are ranked based on their position over the 2008-2012 time period.