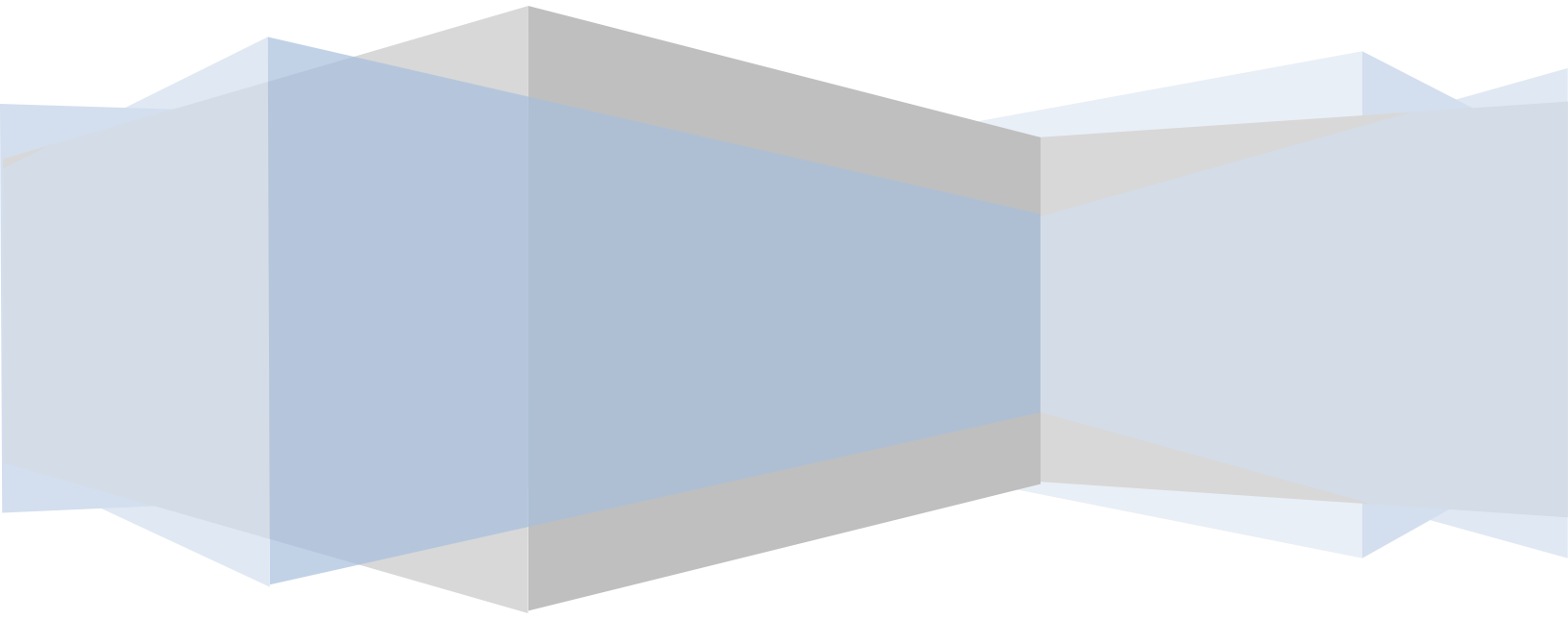
McCullough Research

The Need for a Connecticut Power Authority

A Report to AARP

February 24, 2009



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Executive Summary

Connecticut's electric rates are among the highest in the nation despite electricity restructuring legislation enacted in 1998 that was supposed to bring lower prices for ratepayers. The major reasons for Connecticut's costly utility bills include the failures of New England's wholesale electricity market, the cost of environmental compliance and the fuel mix used to produce electricity. Recent developments, such as cost of service natural gas peakers and the additional generation coming online are helpful, but do not fully address the market's fundamental problems. Mandated reductions in greenhouse gases will raise the price of electricity. The increased use of natural gas to produce electricity makes New England vulnerable to spikes in the cost of this fuel.

This report advocates the creation of a state power authority modeled on the new Illinois Power Agency to bring competition in wholesale power options for Connecticut businesses and consumers. There is nothing revolutionary about such a proposal. Authorities such as the Tennessee Valley Authority, Bonneville Power Administration (Oregon, Washington, Idaho, and Montana), California Department of Water Resources, Western Area Power Administration (fifteen western states), Nebraska Public Power District, and the New York Power Authority have operated well for decades. The decisions to implement these institutions bore many similarities to the challenges encountered by Connecticut.

A Connecticut Power Authority could beat the New England ISO's wholesale price by signing long-term contracts with generators, or financing new plants. Despite the present economic downturn, state bonding will remain attractive when it is to be paid off by future revenues and such taxing authority will be favored by lower interest rates. Funding the new authority could come from a small charge on every utility bill since all customer classes would benefit from the long-term planning and purchasing expertise of the state agency. This report states the challenges and offers reasons why a state power authority will provide solutions to the problems in Connecticut's electricity market.

Contents

Challenges

Connecticut's location, resource mix, and growth have given the state more than its share of challenges with electricity pricing. This has created the anomalous scenario in which Connecticut now has some of the highest electric rates in North America.

Background

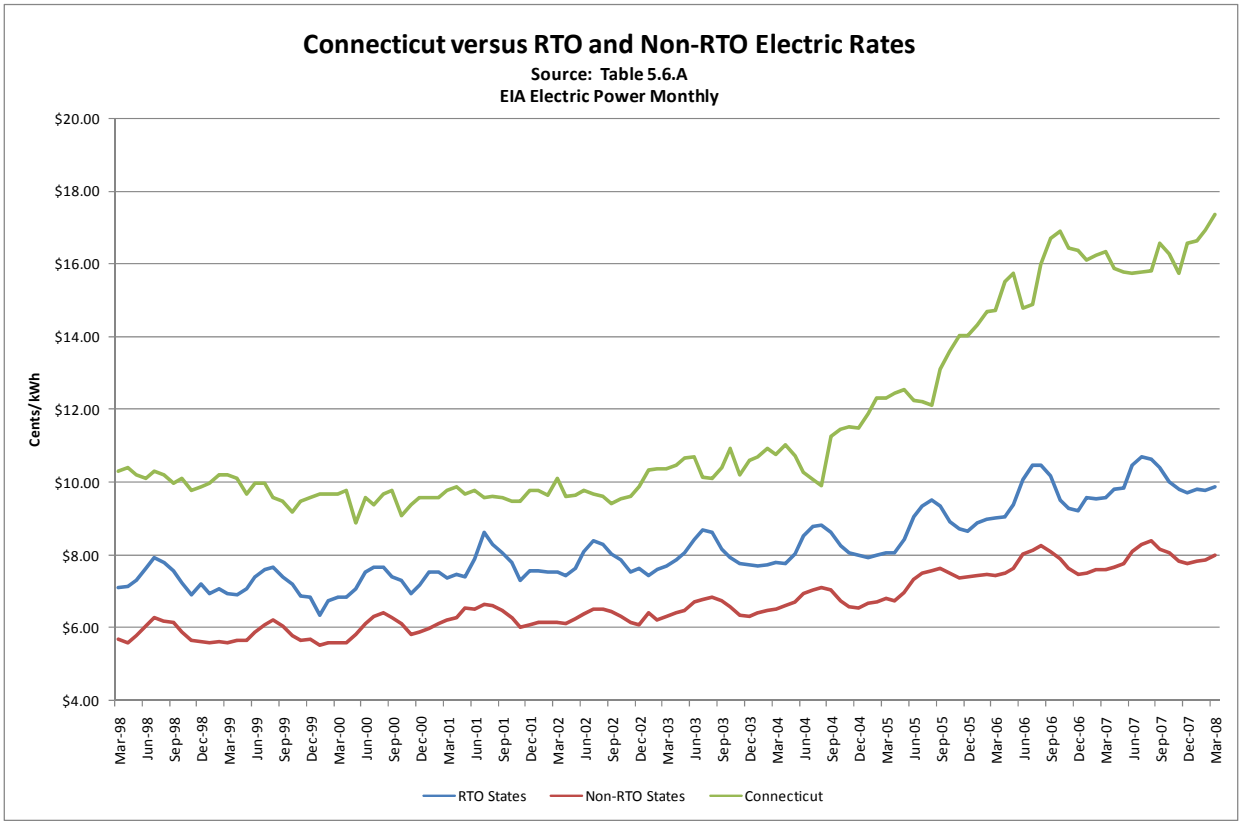
Restructuring simply means that the old way of providing electric power whereby each utility company generates (produces), transmits, and distributes electricity is replaced by companies that only transmit and distribute it. Much like any other commodity, electricity is now purchased in a wholesale market by companies that sell it at retail to their industrial, commercial and residential customers in Connecticut.

Ten years ago, Connecticut enacted Public Act 98-28 believing that electricity restructuring would bring lower prices for residential ratepayers and encourage investments in renewable energy resources. Unfortunately, Connecticut acted before California's restructuring model was fully tested. In 2000, California's experiment in restructuring collapsed catastrophically (popularly known as the California energy crisis or the California meltdown) and has not recovered even today.

Prices in Connecticut and throughout New England reflect the same harsh realities of the failed model in California. Nationwide, states that adopted the California model have fared worse than states that retained traditional structures. In reality, electricity restructuring has not resulted in competitive markets. The New England ISO's[1] own studies indicate that market abuse is

[1] The terms Independent System Operator (ISO) and Regional Transmission Organization (RTO) are often used interchangeably. Associated with the move to restructure the nation's electricity industry is Federal Energy Regulatory Commission Order 2000 that encouraged the formation of RTOs. In this region the non-profit organization is ISO New England, headquartered in Holyoke, Massachusetts. The states with ISO/RTOs are: California, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont, Virginia, West Virginia, and Wisconsin. The non-RTO states are: Alabama, Alaska, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Kansas, Kentucky,

widespread and very costly. Markets generally are not competitive unless they meet a number of conditions, including the existence of many small suppliers, market transparency and freedom of entry. New England's administered markets do not meet such conditions, thus contributing to the higher than reasonable costs experienced by consumers.



The experimental structure at ISO New England discourages investment in cost-effective resources by holding three-year electricity auctions only, too short a period to allow for new resources to be built. This has led to an increasing dependence upon the most expensive resource option, natural gas. In addition, reliability is an issue because existing and new generation resources must be balanced to avoid overloading Connecticut's transmission grid.

The transfer of responsibility for cost effectiveness and reliability from the local utility service area to a multi-state bureaucracy provides little recourse for consumers. Under traditional utility

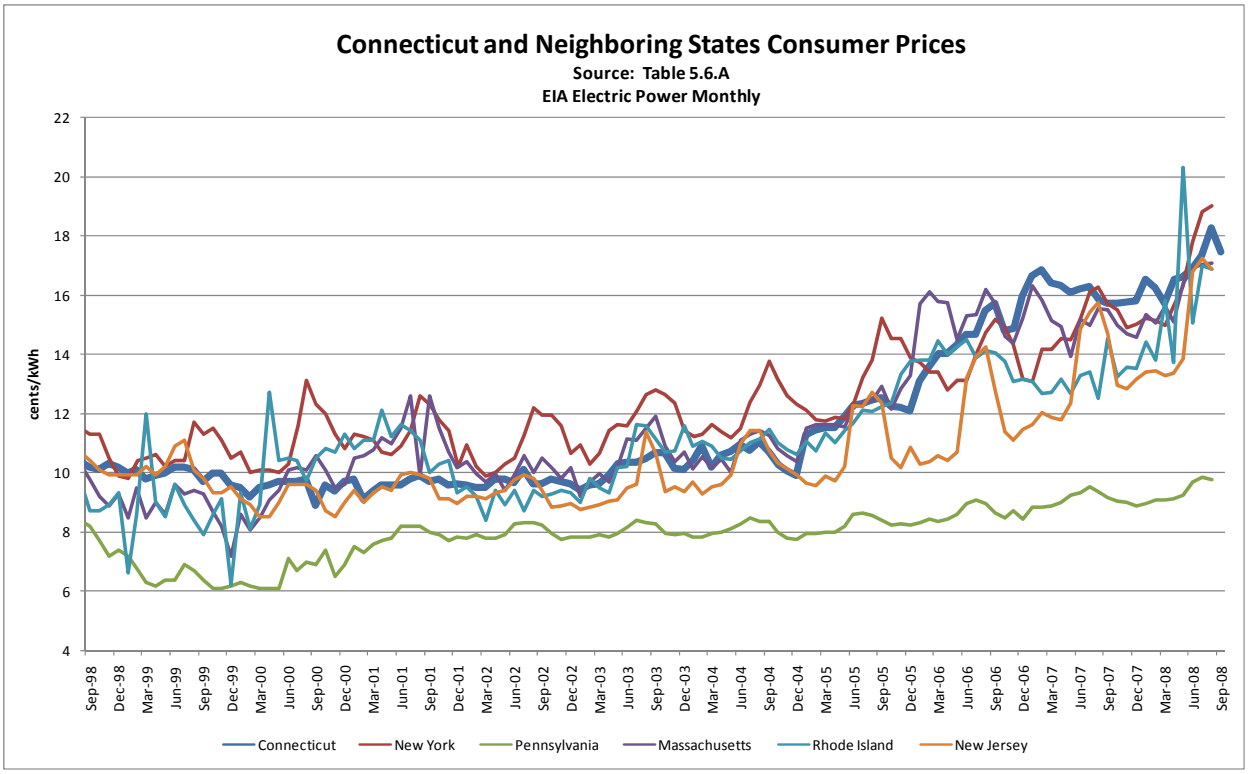
Louisiana, Mississippi, Montana, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, South Carolina, Tennessee, Utah, Washington, and Wyoming.

organization, failures in reliability and cost effectiveness were the provenance of the appropriate public officials and the CEO of the private utility. Under the ISO/RTO model, responsibility for the failures can be assigned to the market design and lack of regulatory oversight. .

Four reasons why Connecticut pays the highest electric rates in the continental United States

1. ISO New England wholesale electricity markets do not work well for consumers

While experts have conducted arcane debates concerning the benefits of the wholesale markets administered by ISO New England, the simplest test is whether Connecticut's electric rates have outpaced its neighbors:



ISO New England is neither competitive nor transparent, as two recent documents reveal. First, the 2007 Assessment of the Electricity Markets in New England by an independent market monitor[2] shown below gives thirteen recommendations for a range of improvements, while indicating that not all are feasible in the short term. The recommendations are indicative of the complexity and expense of the current market design.

[2] 2007 Assessment of the Electricity Markets in New England, Potomac Economics, June 2008, page 17; http://www.iso-ne.com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf

POTOMAC ECONOMICS

Executive Summary

I. Table of Recommendations

Recommendation	Section	High Benefit	Feasible in ST[9]
Energy Pricing and Market Design			
1. Evaluate potential pricing changes that would allow costs of fast-start units to be more fully reflected in real-time prices.	VII.B	✓	
2. Develop rules to allow demand response resources to set prices when they are needed to avoid a shortage.	VII.D	✓	
3. Consider replacing the current ex post pricing process with one that uses ex ante prices for settlement.	VII.E		
4. Consider providing suppliers with flexibility to modify their offers closer to real-time to reflect changes in marginal costs.	VIII.E		
Ancillary Services Markets			
5. Set the local RCPFs at levels that are more consistent with the costs incurred to meet the local-area reserve requirements.	V.B	✓	✓
6. Create additional local reserve zones in the real-time market to satisfy the local reliability requirements more efficiently.	V.C		✓
7. Consider whether the "Rest of System" TMOR requirement is necessary in the forward reserve market.	V.D		✓
8. Consider replacing the forward reserve market's price cap with a tiered cap to recognize higher-value reserves.	V.D		✓
9. Evaluate the benefits of moving to a regulation market that is co-optimized with the energy and ancillary services markets.	VI.D		
System Operations			
10. Consider changes in rules or cost allocation to discourage inefficient self-commitments after the RAA process.	VIII.B		✓
11. Develop provisions to coordinate the physical interchange between New York and New England in real-time.	III.C	✓	
12. Discontinue relaxation of violated transmission constraints -- set penalty factors that reflect the value of constraints and allow them to determine LMPs when a constraint is violated.	VII.C		✓
Market Power Mitigation			
13. Modify the mitigation criteria to address inflated NCPC payments to suppliers whose units are frequently needed for local reliability.	VIII.B		✓

9 *Feasible in Short-Term*: indicated if the recommendation is likely to be feasible within one to two years at a reasonable cost. Others likely require study of costs and benefits, or research to identify a feasible approach. *High Benefit*: Indicated for recommendations that will likely produce considerable efficiency benefits.

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Second, Connecticut's attorney general and consumer counsel filed a motion with federal regulators to intervene and protest because ISO New England's 2009 administrative cost proposal contains no evidence that the estimated expenses for executive and total employee compensation, staffing levels, depreciation and amortization, and external

affairs activities are just and reasonable.[3] There is little reason to assume that New England's non-profit energy administrator values transparency and clear explanations of its operating costs.

When New England left the traditional regulatory formula in favor of the complex and opaque ISO market structure, it fundamentally changed the method by which consumer rates were calculated. Under the traditional regulatory formula, average generation costs are paid by consumers. Under ISO New England, consumers now, theoretically, pay the marginal cost of the least-efficient unit dispatched. (This report will address how competition has failed to deliver marginal cost under the ISO in the next section.)

The difference between average cost and marginal cost is called "producers' surplus" by economists. The change from traditional regulation to ISO New England's structure conferred an enormous one-time windfall on the region's electric generators. As discussed below, the windfall conferred on electricity producers has been greatly increased by failures in the ISO's administered markets.

2. The competition envisioned when Connecticut's restructuring bill passed in 1998 has failed to develop

After a transition period, it was expected that residential ratepayers would be able to pick and choose providers based upon their preferences for lowest rate, percentage of renewable generation, etc., from a variety of electricity service providers. However, a competitive selection of generating alternatives for residential ratepayers has failed to develop in Connecticut and New England.

Commodity markets in general are characterized by published prices; bidders that can shop openly among suppliers; and non-economic outcomes that are not shielded from public/regulatory scrutiny. The issue for Connecticut is that New England's market

[3] Motion to Intervene and Protest of New England Advocates, FERC Docket No. ER09-197-000, November 21, 2008.

structure fails to meet the definition of perfect competition. Economist Paul Samuelson has identified five conditions for perfect competition (many buyers, many sellers, transparency, freedom of entry, freedom of exit); below are the related problems.

Many buyers: As a general rule, only the ISO/RTO itself is the buyer. This would naturally allow it to exercise monopsonistic purchasing power, but the RTO is limited to accepting the supply curve regardless of distortion. The problem is accentuated by the enormous cost of disruption should the RTO be unable to buy additional energy, for example, to offset a power outage.

Many sellers: Also as a general rule, the number of sellers is small and is able to exercise substantial market power. Each represents a minor part of the market. Hence, it is optimal for the seller to price the electricity for sale at marginal cost. In practice, prices vary greatly from marginal cost. In different RTOs, market manipulation gambits have led to oddities in pricing. In fact, in every American RTO, at least some non-economic bidding occurs daily.[4]

Transparency: To varying degrees, characteristics of transparency are largely missing from the nation's electricity markets, but this has not stopped the supporters of ISO/RTOs from hypocritically proclaiming that transparency makes the manipulation of the electricity market easier to identify and monitor. If the major bidders have substantially more information at hand than many of their competitors (true of nearly all U.S. restructured electric power environments), then the large bidders can use the information to their advantage. This advantage is further strengthened by the ability of the bidders to manipulate the demand curve for balancing energy in many cases.

Freedom of entry: In electricity markets that operate in real time, there is effectively no freedom of entry. When the bid stack is exhausted, additional supplies can only be procured by calling upon the Reliability Must Run (RMR) generation units available to

[4] For a quick survey of bidding and pricing anomalies, see Analysis of the Balancing Energy Market, McCullough Research, February 20, 2009.

the ISO's dispatchers. The rules concerning such arrangements have been a significant causation of the high costs to consumers throughout New England.

Freedom of exit: By definition, an ISO/RTO cannot leave the market. Individual suppliers are able to exit the market, but as with entry, the ability to change participation in the short-term is limited. The effort by one market participant to exit PJM has taken years and millions of dollars in litigation costs.[5]

The result of the lack of competition has created wholesale prices considerably above marginal cost. In 2006 and 2007 bulk power prices in New England were always greater than normal efficiencies of power plants, even on an average monthly basis. In a competitive market, prices should reflect underlying economics and heat rates of 7,000 for base load and 10,000 for peak load would be expected. In New England, even low load months experience high prices.

Figure 2 from the 2007 Assessment of the Electricity Markets in New England shows that the prices in New England never approximate plant efficiencies. During relatively low load winter months, ISO New England averages 8,000 mmbtu per kilowatt-hour – over ten percent higher than we would expect in a competitive market. For instance, in August 2007, the heat rate for the entire month averaged that of a peaker, even including nights and weekends when lower-cost units would have been used. In August, the price of natural gas for electricity generation was $6.87/mmbtu.[6] Overall, these high heat rates represent bids that are higher than marginal cost – a frequent occurrence when pivotal suppliers can exert market power.

[5] See for example, "PJM wants Duquesne to pay if it leaves power grid," Reuters, December 5, 2007, and "Duquesne Light wins approval to leave PJM," Reuters, January 17, 2008. The issue also raises questions about "whether a utility can be a member of two RTOs at once, whether FERC can authorize the breach of a bilateral contract and whether FERC should determine Duquesne's financial liabilities" should a settlement pending at FERC be approved ("MISO asks FERC to make Duquesne pay exit fees, costs," *Restructuring Today*, December 18, 2008).
[6] Price = natural gas price x heat rate/1000.

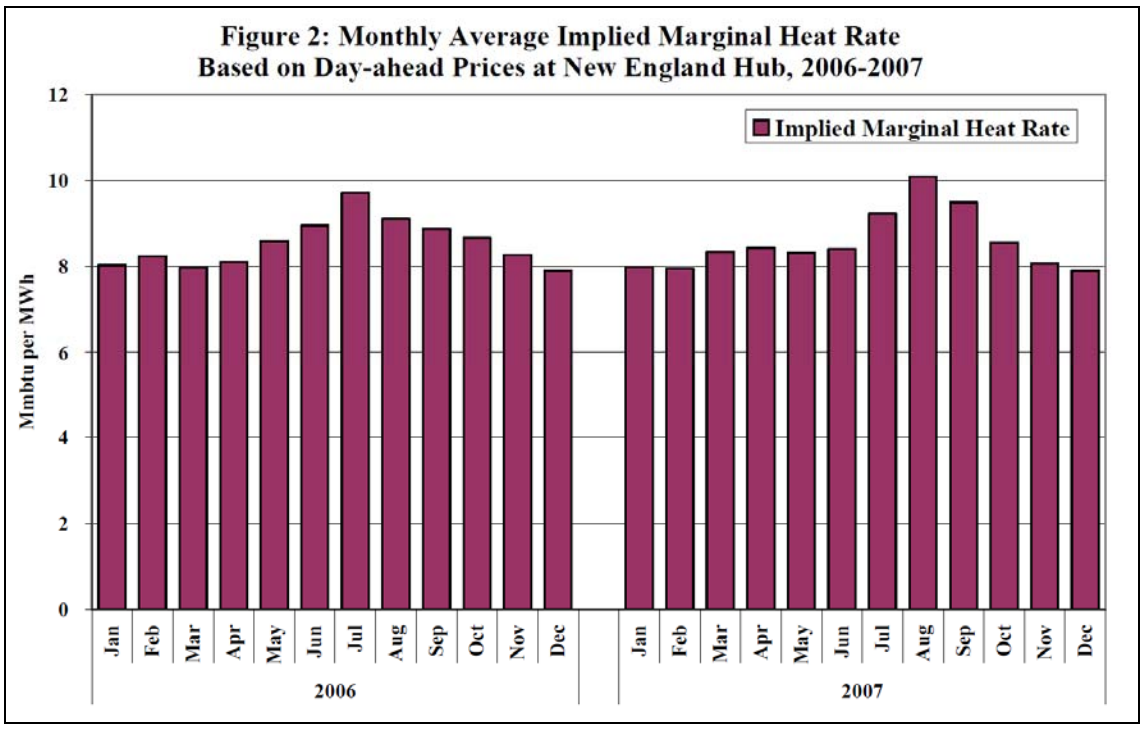
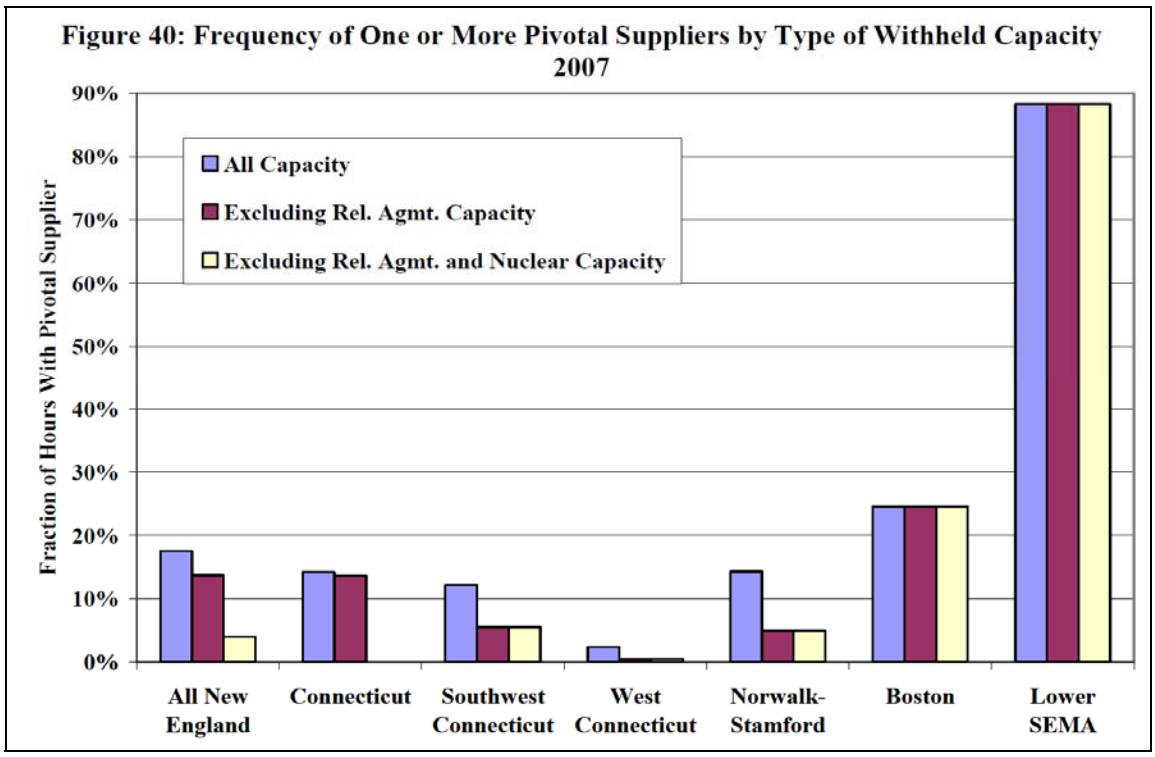


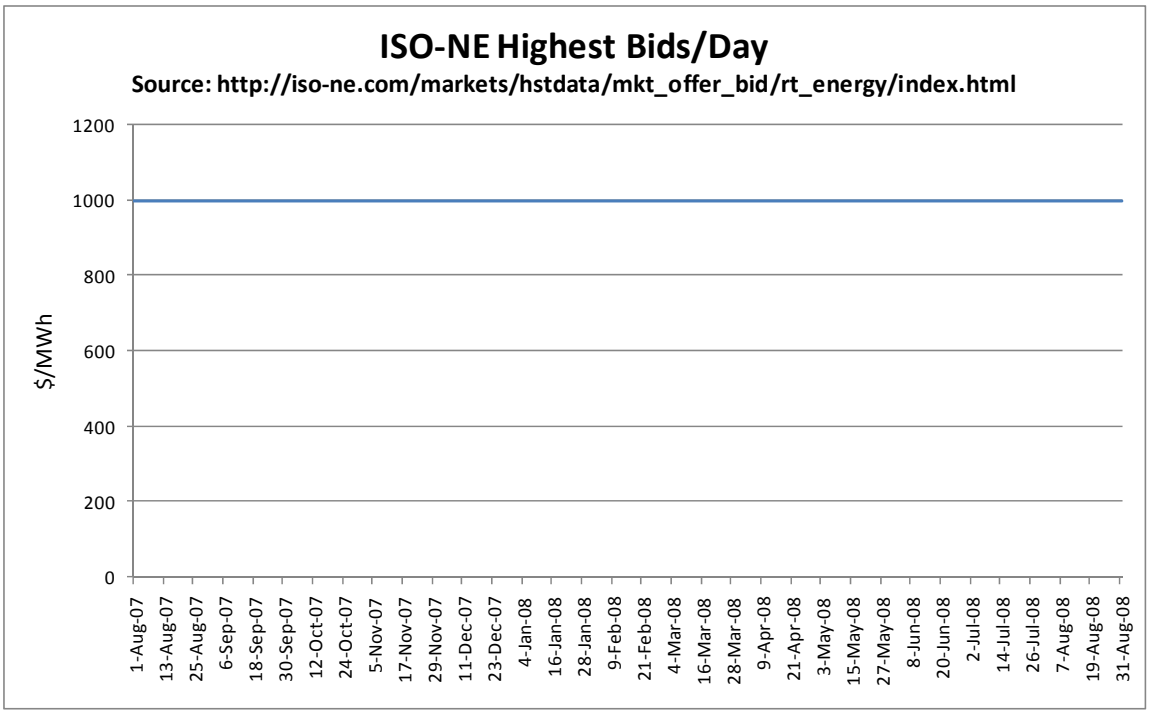
Figure 40 from the 2007 Assessment of the Electricity Markets in New England indicates that pivotal suppliers (suppliers whose generation cannot be replaced by competing supplies) occur frequently.[7]

[7] Figures 2 and 40 appear in the 2007 Assessment of the Electricity Markets in New England, Potomac Economics, June 2008, pages 20 and 152; http://www.iso-ne.com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf



This chart indicates the percentage of the time where pivotal suppliers (market participants capable of exerting market power) are suspected of withholding capacity from the market. In some regions of New England this occurs almost 90% of the time, Connecticut's experience is only a bit above 10% of the time. Unfortunately, it is clear why prices in New England are so high relative to fuel costs and plant technology.

Although ISO New England's market surveillance reports do not address the actual bidding behavior in the administered markets, a cursory review shows that the bids provided by the market participants often depart markedly from those we would expect in normal markets. Economic theory predicts that in competitive markets the supply curve should reflect the marginal costs of the bidding units. In New England, very high bids are commonplace. In fact, bids at $999.99/MWh or higher occur every hour:



Since no plant in New England has marginal costs that remotely approach $1,000/MWh, the continuous submission of non-economic bids is a symptom of market manipulation. Marginal costs above $100/MWh are unusual given current fuel costs, let alone when fuel is ten times as high. If a new grocery store opened in the neighborhood with prices of $1,000 per head of lettuce, even the most committed advocate of grocery stores would quickly deduce that something irregular was taking place.

3. The costs of environmental compliance increase electricity prices

In addition to reducing mercury and the other noxious by-products of electricity generation, An Act Concerning Connecticut Global Warming Solutions passed by the General Assembly in 2008 sets as a target greenhouse gas emissions (GHG) reductions of at least 10 percent below 1990 levels by the year 2020 and at least 80 percent below 2001 levels by the year 2050.[8]

[8] http://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm

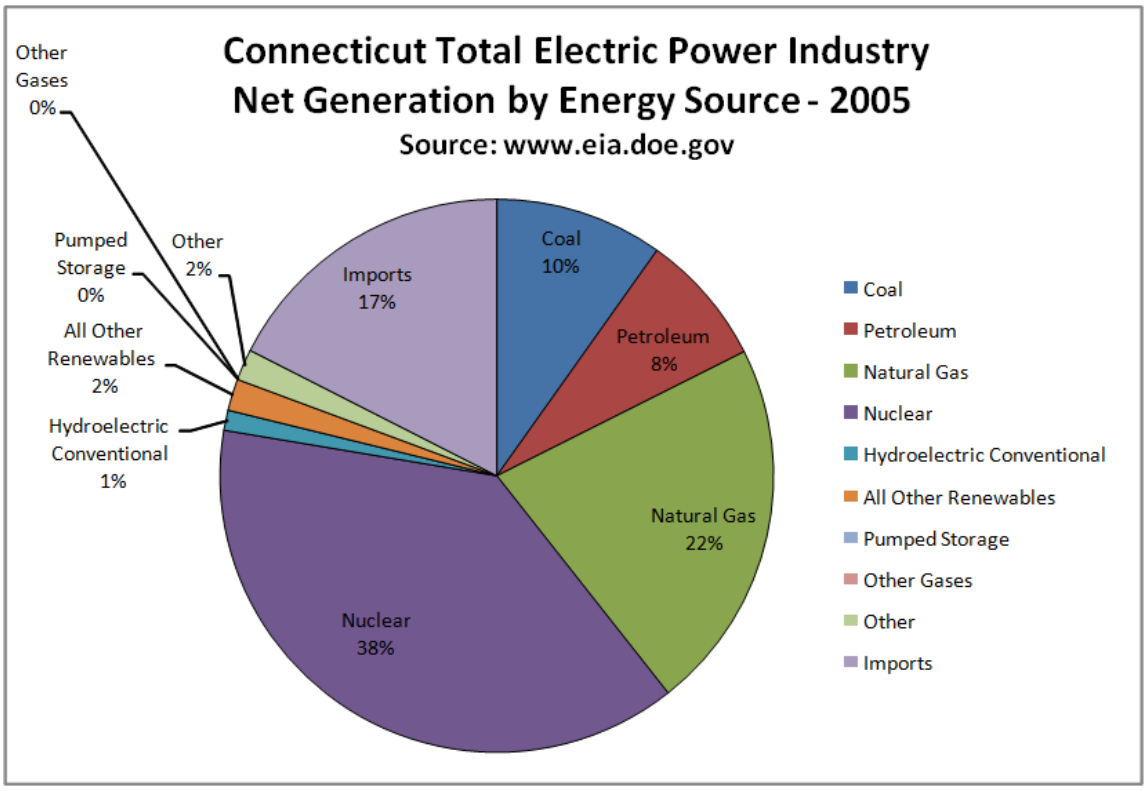
To this end, Connecticut is a participant in the Regional Greenhouse Gas Initiative (RGGI), "a cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States….These ten states will cap CO_2 emissions from the power sector, and then require a 10 percent reduction in these emissions by 2018."[9]

The first auction of carbon-offset allowances under RGGI was held on September 25; the second was held on December 17, and the third will be held on March 18, 2009. Most states, including Connecticut, will use the proceeds from these auctions to "augment the existing funding by electricity ratepayers of the states' energy-efficiency programs."[10] A regional model rule is being adapted "to state-specific formatting, and state-specific policies are being developed," including "the size of the consumer benefit set-aside," "uses for the revenues derived from the consumer benefit set-aside (e.g., what types of projects might be supported)," and "allowance allocation methodologies."[11]

4. Connecticut's fuel mix

As shown in this pie chart, about half of the electricity used in Connecticut is generated by the two nuclear reactors at the Millstone facility in Waterford owned by Dominion Resources.

[9] http://rggi.org/about
[10] 2008 Regional System Plan, ISO New England Inc., October 16, 2008, page 83; http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf
[11] For Connecticut developments see http://www.ct.gov/dep/cwp/view.asp?a=2684&q=332278&depNav_GID=1619



One of the promises of ISO New England was that it would facilitate diversity in the resource mix.

ISO New England's stated responsibilities are:

- Reliable day-to-day operation of New England's bulk power generation and transmission system
- Oversight and administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process[12]

Besides setting the wholesale price of electricity, the ISO is now implementing a new Forward Capacity market with an annual auction mechanism to identify and procure "the required amount of capacity at the least cost to preserve reliability in New England."[13]

[12] 2008 Regional System Plan, ISO New England Inc., October 16, 2008, page 7; http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf

[13] Ibid, page 109; page 40 provides detail: "The FCM's Forward Capacity Auctions are designed to procure capacity roughly three years (40 months) in advance of when the commitment period begins. This lead time allows capacity suppliers to develop new capacity resources and enables the ISO to plan for these new resources. However, to limit

The transition period before the new regime is fully operational started in December 2006 and will last through May 2010; the first Forward Capacity market auction was held February 4-8, 2008, the second on December 8, and a third will be held on October 5, 2009.

ISO New England also issues state and regional forecasts. The most recent plan (October 16, 2008) reports:

> Capacity Market—The first FCM auction successfully cleared 1,800 MW of new demand and supply resources. Assuming that these new resources and existing ones meet their capacity obligations, the region will not need additional resources until 2015. Because over 12,000 MW of resources are seeking qualification for the ISO's second FCM auction, this new capacity market appears highly successful.[14]

After the December 8 auction, the ISO declared:

> Bidding among the 42,777 megawatts (MW) of eligible resources began at $12.00 per kilowatt-month (kW-month) and systematically decreased throughout eight consecutive auction rounds. The final round's price fell to $3.60 per kW-month, the floor price established for this auction. The auction secured the 32,528 MW needed for reliability in 2011 to 2012 at that floor price, along with an excess of 4,360 MW. Notable in the second auction's results is the continued growth of demand-side resources within the region. More than 2,900 MW of demand-side resources cleared in FCA-2, up from the 2,500 MW of this resource type secured in February's FCA-1. Supply-side resources selected in FCA-2 totaled 33,988 MW.[15]

Restructuring was supposed to encourage diversity of the fuels used to produce electricity, especially renewables. Most newly built plants use natural gas, considered the most environmentally benign fossil fuel, since lower emissions are produced in making electric power. The increased use of natural gas to produce electricity adds to the cost of

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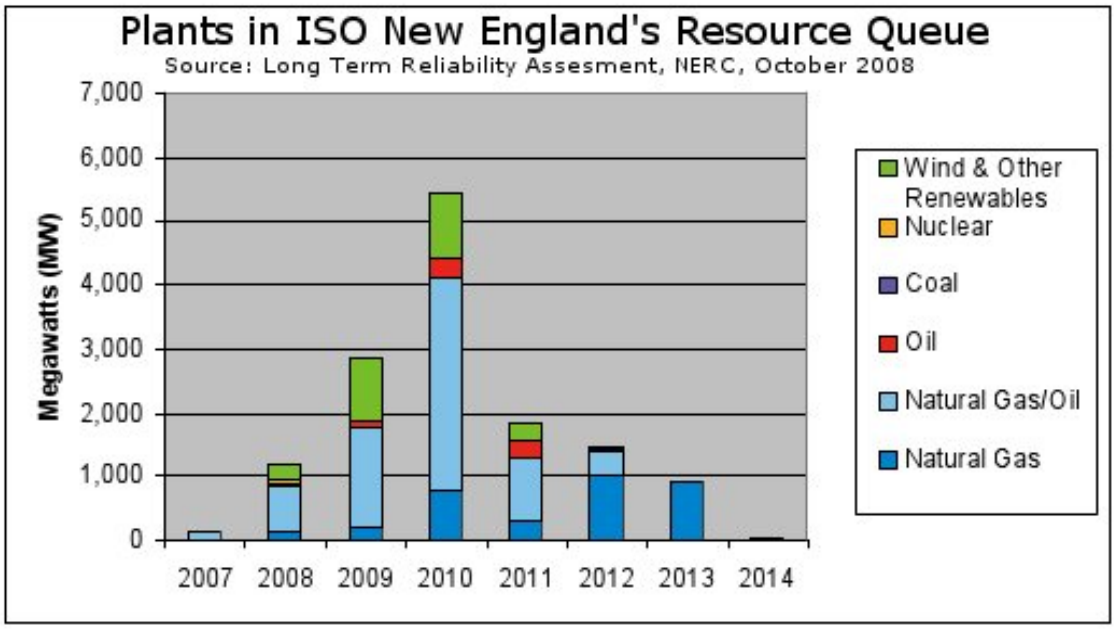
the length of the transition period, the first auction, for delivery in June 2010, is allowing only about 28 months for the development of resources. The lead time to develop resources for future capacity commitment periods will gradually increase in subsequent auctions to reach the 40-month advance period."

[14] Ibid, page 160.

[15] "New England's Second Power Resource Auction Produces Positive Outcomes for the Region," ISO New England, December 10, 2008, http://www.iso-ne.com/nwsiss/pr/2008/final_fca2_results_121008.pdf

monthly bills and makes New England vulnerable to spikes in the fuel's cost. Plants in ISO New England's new resource queue are overwhelmingly natural gas–fueled:[16]



Plants in ISO New England's queue are primarily natural gas, ranging from a low of 60% in 2009 to 100% after 2011. The end result of the ISO's programs is to expand – not reduce – dependence on fossil fuels over time.

It is unlikely that ISO New England will be able to deliver competitive, cost-effective resources to Connecticut in the future.

While there are positive signs in certain areas, both the structure of administered markets and the choice of resources do not support optimism. Many entities are lobbying FERC to adjust the administered markets in a manner that would produce higher prices. The logic is that even the current, very high prices are unable to provide sufficient incentives for market participants to invest in new generation and transmission resources. While the debate lies beyond the scope of this report, it is important to note that there is no electricity market in the ordinary sense of the

[16] 2008 Long Term Reliability Assessment, NERC, October 2008, page 135; http://www.nerc.com/files/LTRA2008.pdf

term (someone with a product to sell can negotiate the price with any consumer). If the lobbying efforts at FERC succeed, prices will simply be set higher by administrative action.

As mentioned above, ISO New England's resource queue is overwhelmingly dominated by natural gas units, now the most expensive options available in the resource mix. As is common with administered markets, the rules adopted by the ISO virtually direct the outcome of the bidding process. Since the ISO's Forward Capacity auction is for three years, it means that the only viable plants are those that can be built quickly and have a chance to capture higher than normal market returns.

In the case of New England, none of the more cost-effective options are among the winners of the first Forward Capacity auction: clean coal, nuclear, and other innovative options simply are not being considered. While this report does not advocate specific fuel choices, it does advocate creating mechanisms where the full range of options is available to Connecticut businesses and consumers.

Recent developments, such as cost of service natural gas peakers and the additional generation coming online are helpful, but do not fully address the fundamental market problems.

In 2007, the General Assembly passed Public Act 07-242, An Act Concerning Electricity and Energy Efficiency. Section 51 of the new law requires that "electric distribution companies[17], in consultation with the Connecticut Energy Advisory Board…shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources…." The law states that each company's procurement plan must include:

> "(1) the total amount of energy and capacity resources needed to meet the requirements of all customers,
> (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs,

[17] The two are Connecticut Light & Power Company (CL&P) and United Illuminating Company (UI).

> (3) needs for generating capacity and transmission and distribution improvements,
> (4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and
> (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources."

The Connecticut Energy Advisory Board's (CEAB) first plan[18] under the new law was submitted to the Department of Public Utility Control (DPUC), the state regulatory agency that ultimately approves the plan and oversees the procurement process. The CEAB views its new plan as a "mechanism through which the state can weigh environmental decisions and data in electric planning and conversely, inform the state's environmental decisions about their potential affect on electric service and costs."[19] It has recommended to the DPUC that future plans "should specifically analyze the cost and potential benefits" of resource options including:

1. Import of renewables and nuclear power from Canada, including transmission requirements and costs.
2. Combined heat and power potential – small scale and grid-connected projects.
3. Connecticut and domestic sited additional nuclear capacity.
4. Connecticut and regional potential for advanced or clean coal generation with or without carbon sequestration.[20]

The DPUC is expected to issue a draft ruling in December.

Section 50 of the same 2007 legislation asks the DPUC to evaluate the need for more peaking generation. Peaking plants "generally run on diesel fuel or natural gas and are uniquely equipped to start up quickly and provide energy on short notice, usually on hot summer days when air conditioning use spikes."[21] On June 25 the DPUC awarded contracts for 678 MW of new natural gas peaking generation[22] to Bridgeport Energy II in Bridgeport, PSEG in New Haven, and

[18] Also known as an Integrated Resources Plan (IRP).
[19] Connecticut Energy Advisory Board Brief, Docket 08=07-01, Submitted October 10, 2008, page 8; http://www.dpuc.state.ct.us/dockcurr.nsf/f7de85eded62752a8525655d005653b8/831cfb4380ecc347852574de00690cce/$FILE/10-10-08%20CEAB%20IRP%20BRIEF.pdf
[20] Ibid, page 9.
[21] http://www.ct.gov/csc/lib/csc/publications/state_of_energy_july_2008.pdf
[22] DPUC Review of Peaking Generation Projects, Docket No. 08-01-01, Final Decision, June 25, 2008.

GenConn in Milford. At the time Mary Healey, Consumer Counsel, explained, "The three approved peaking plants will be paid for by regulated prices according to their costs of service, and not based on what the ISO New England markets provide. This benefits the ratepayers by providing a hedge against unreasonable market outcomes, while also ensuring the plant owner of a stable income stream for financing. The new peaking plants should thus be a 'win-win' for both the ratepayers and the project developers."[23] The plants will begin operating in 2010 and 2012. The same model will work for less expensive plants than those fueled by natural gas.

ISO New England forecasts the requirement to build more peaking plants:

> **Energy and Load Growth—**By the end of the 10-year planning period, the region can expect lower growth in the use of electric energy than the RSP07 forecast: 0.8% per year compared with 1.2% per year. Summer peak loads also will grow at a lower rate—1.2% per year compared with 1.7% per year. The system load factor will continue to decline, which will lead to the need for more peaking resources.[24]

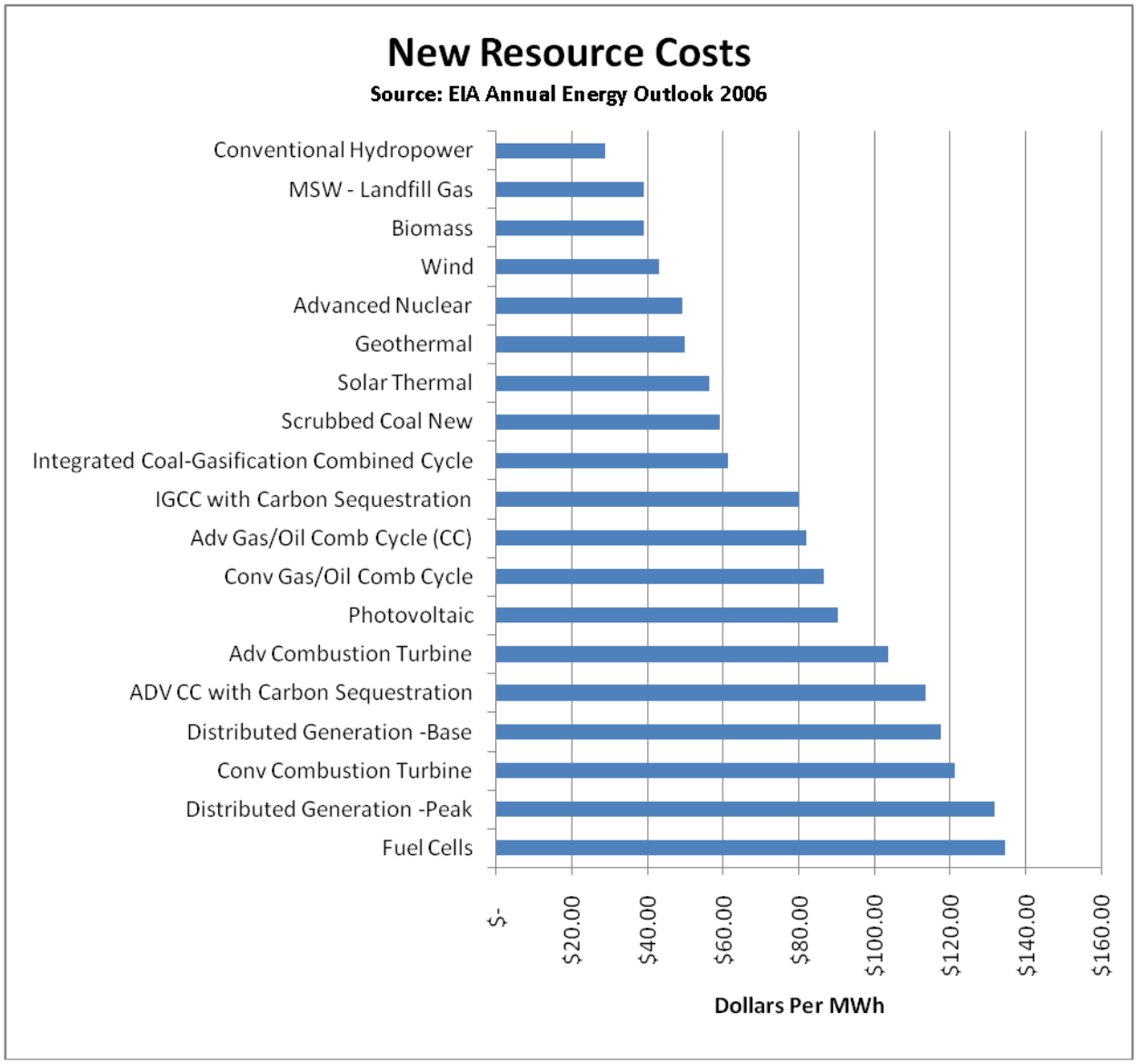
The U.S. Energy Information Administration uses the following resource costs in its annual planning:[25]

[23] http://www.americantowns.com/ct/hartford/news/office-of-consumer-counsel-applauds-dpuc-s-final-decision-in-peaking-generation-docket-108581
[24] 2008 Regional System Plan, ISO New England Inc., October 16, 2008, page 160.
[25] Electricity Market Module, Energy Information Administration, June 2008, page 3.

Technology	Online Year[1]	Size (mW)	Leadtime (Years)	Base Overnight Cost in 2007 ($2006/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2007[4] (2006 $/kW)	Variable O&M[5] ($2006 mills/kWh)	Fixed O&M[5] ($2006/kW)	Heatrate[6] in 2007 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2011	600	4	1,434	1.07	1.00	1,534	4.46	26.79	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2011	550	4	1,657	1.07	1.00	1,773	2.84	37.62	8,765	7,450
IGCC with Carbon Sequestration	2011	380	4	2,302	1.07	1.03	2,537	4.32	44.27	10,781	8,307
Conv Gas/Oil Comb Cycle	2010	250	3	683	1.05	1.00	717	2.01	12.14	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2010	400	3	654	1.08	1.00	706	1.95	11.38	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,254	1.08	1.04	1,409	2.86	19.36	8,613	7,493
Conv Combustion Turbine[8]	2009	160	2	476	1.05	1.00	500	3.47	11.78	10,833	10,450
Adv Combustion Turbine	2009	230	2	450	1.05	1.00	473	3.08	10.24	9,289	8,550
Fuel Cells	2010	10	3	4,653	1.05	1.10	5,374	46.62	5.50	7,930	6,960
Advanced Nuclear	2016	1350	6	2,143	1.10	1.05	2,475	0.48	66.05	10,400	10,400
Distributed Generation -Base	2009	5	2	972	1.05	1.00	1,021	6.93	15.59	9,200	8,900
Distributed Generation -Peak	2010	2	3	1,168	1.05	1.00	1,227	6.93	15.59	10,257	9,880
Biomass	2011	80	4	2,490	1.07	1.05	2,809	6.53	62.70	8,911	8,911
MSW - Landfill Gas	2010	30	3	1,773	1.07	1.00	1,897	0.01	111.15	13,648	13,648
Geothermal [7,9]	2011	50	4	1,057	1.05	1.00	1,110	0.00	160.18	35,376	33,729
Conventional Hydropower[9]	2011	500	4	1,410	1.10	1.00	1,551	3.41	13.59	10,022	10,022
Wind	2010	50	3	1,340	1.07	1.00	1,434	0.00	29.48	10,022	10,022
Wind Offshore	2011	100	4	2,547	1.10	1.03	2,872	0.00	87.05	10,022	10,022
Solar Thermal[7]	2010	100	3	3,499	1.07	1.00	3,744	0.00	55.24	10,022	10,022
Photovoltaic[7]	2009	5	2	5,380	1.05	1.00	5,649	0.00	11.37	10,022	10,022

To supply electricity to the consumer, a power plant must be built (financing the bricks and mortar cost of the unit), and then operated (paying for the fuel and maintenance of the plant). The values in the table above are the Energy Information Administration's best estimates of these costs. Some plants like wind require little in the way of fuel. Natural gas units, however, have most of their cost in fuel.

Based on the costs above, the baseload costs of the major options are:



The chart readily shows that New England's current plans are not even remotely cost-effective. The reason why natural gas is such a costly option is that it is a close substitute for imported foreign oil. Moreover, much of the supply targeted for New England is also imported. Again, while this report need not argue for one fuel choice over another, it is important to note that longer lead time projects with lower overall costs are not being selected by the ISO's three-year bidding process in the Forward Capacity auction.

Reliability is a Concern in Connecticut

Reliability is a particularly difficult problem for several reasons. First, since storage of electricity is a challenge in many areas of North America, it is critical to have more capacity on line every minute of every day than the requirements of consumers. Second, when reliability problems develop, it is important that the response of the system operator be quick and sure. A debate exists in the U.S. and Canada about how to achieve these goals. One theory is that the system is best managed by additional levels of bureaucracy to enact and enforce reliability rules. An opposing theory is that keeping responsibility close to the ultimate consumer will avoid "the tragedy of the commons". Advocates of both theories have used the vast blackout of 2005 as evidence to back their arguments.

In 2005, Congress established a new set of rules to assure the reliability of the nation's electric grid. Under the new law, the mission of the North American Electric Reliability Corporation (NERC) "is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC assesses adequacy annually via a 10-year forecast and winter and summer forecasts; develops and enforces reliability standards; monitors the bulk power system; audits owners, operators, and users for preparedness; and educates, trains and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada."[26] NERC works closely with the Northeast Power Coordinating Council, whose geographic area includes New England.

Connecticut usually appears on NERC's Summer Watch List, although a transmission line between Bethel and Norwalk built in 2006 has made the state's transmission grid more reliable, and a second new line will begin operating in 2009.[27] For a state that depends upon imported power, an extended period of hot, humid weather (i.e. heavy use of air conditioning) is a serious issue. New, more efficient natural gas peaking plants and voluntary reductions in energy use by

[26] http://www.nerc.com/news_pr.php?npr=13
[27] The two construction phases are known as the Southwest Connecticut Reliability projects.

industry, businesses, and homes reduce stress on grid, but even so, Connecticut's energy agencies have recommended more connections to New York and Rhode Island (the New England East-West Solution project) to ensure reliability.[28]

ISO New England's 2008 plan states: "For the Greater Southwest Connecticut load pocket, the 301 MW of fast-start resources offered in the summer 2008 FRM auction will not be sufficient to meet that area's summer operating-reserve requirement until Phase 2 of the Southwest Connecticut Reliability Project is implemented, which is expected in 2009. This project will reduce the need for operating reserves by approximately 500 MW in Southwest Connecticut. The Greater Connecticut load pocket appears to need an additional 225 to 325 MW of fast-start resources from summer 2008 through 2012, a period preceding the expected addition of the NEEWS project."[29]

In addition, NERC's "Special Report: Electricity Industry Concerns on the Reliability Impacts of Climate Change Initiatives" released on November 10, 2008 highlights reasons "to review the collective impact of" initiatives such as RGGI in the northeast "on the bulk power system and identify effective means to help the electric industry meet these climate change initiatives without degrading system reliability."[30]

Solutions

FERC has effectively pre-empted wholesale market issues in its hands-off regulation of ISO New England. While it is possible that the Obama administration will attempt to return FERC to a consumer protection role, FERC's current stance is effectively caveat emptor – let the buyer beware. In order to lower wholesale power costs, Connecticut needs to assure a supply of cost-effective and environmentally friendly resources.

[28] This is the New England East-West Solution project.
[29] 2008 Regional System Plan, ISO New England Inc., October 16, 2008, page 7; http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf
[30] http://www.nerc.com/files/2008-Climate-Initiatives-Report.pdf

The Illinois experience and the creation of a state power authority

Facing similar pressures, the state of Illinois with bipartisan support passed Illinois Public Act 095-0481 in 2007, that established a new Illinois Power Agency as a fee-based agency.[31] Section 1-5 of the law defines the new agency's four goals and objectives:

> "(A) Develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois. The procurement plan shall be updated on an annual basis and shall include renewable energy resources sufficient to achieve the standards specified in this Act.
> (B) Conduct competitive procurement processes to procure the supply resources identified in the procurement plan.
> (C) Develop electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.
> (D) Supply electricity from the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois."

The law is the direct result of a wholesale electricity auction held in the fall of 2006 that determined the retail price to be paid by business and residential consumers beginning in January 2007. Shortly after New Year's Day, consumer complaints began to pour in to state legislators and the Illinois Commerce Commission as the size of monthly utility bills almost doubled. In the ensuing months, the Attorney General of Illinois began an investigation of the auction's operation and filed several federal and state actions, and elected officials debated legislative solutions to the failed procurement process. Finally, on August 30 a bill was signed into law. Moreover, the state attorney general was able to successfully conclude negotiations with the utilities to refund more than a billion dollars to consumers. While the new agency was being set up, the Illinois Commerce Commission conducted an interim procurement plan during the spring

[31] http://www.ilga.gov/legislation/publicacts/95/PDF/095-0481.pdf

of 2008 following the new procurement model. On September 3, 2008 the new Illinois agency[32] submitted its first procurement plan to the ICC for review and public comment. On January 7, 2009, the ICC approved the plan; upon hiring a procurement administrator, the procurement process will be undertaken in spring 2009.[33]

Benefits of a Connecticut Power Authority (CPA)

Establishing a state power authority has great potential to help Connecticut mitigate high electricity prices. The possibility exists to provide power and realize savings in an efficient manner. Several key benefits associated with the formation of a state power authority in Connecticut are outlined below.

A CPA could have the ability to finance new plants either by outright ownership or by long-term contracts. Since renewable resources are likely to be high capital cost options, this may be the only short-term solution for adding these options to the resource mix in Connecticut. It is also possible that a state power authority whose sole mandate is planning/procurement could receive better terms and more benefits because of "clout".

By signing long-term contracts with resource developers, the CPA could beat New England ISO's wholesale price. The CPA could provide power at fully allocated cost to Connecticut consumers and businesses and be able to choose from a broader portfolio of plants than those currently selected in the Forward Capacity market including those that are significantly more cost effective. In other words, it could buy power more cheaply because there is no longer an auction process, and because long-term bilateral contracts should result in lower prices.

A Connecticut Power Authority could be similarly constituted on the model of the new Illinois Power Agency which is tax exempt by statute and has the authority to issue both taxable and tax-

[32] http://www.ibhe.org/FridayMemo/misc/080418_Pruitt.pdf and http://www.icc.illinois.gov/e-Docket/reports/browse/docket_detail.asp?id=9040&no=08-0519
[33] ICC Approves Illinois Power Agency Electricity Procurement Plan, press release, January 7, 2009; http://www.icc.illinois.gov

free revenue bonds to build in-state generation plants.[34] The use of tax-free bonds would usually lower the overall financing costs for new generation. This would allow the CPA to compete with the market to push the price of electricity closer to cost-of-service. Tax-free bonds offer lower interest rates than other types of bonds. Therefore, a CPA would have advantages in financing over investor-owned utilities.

A CPA could extend financing to a non–state-owned plant in exchange for traditional regulatory treatment. The CPA could function as either a financing entity or a guarantor for developer-built power plants. The model for this is the "acquisition" and "net billing" techniques used by the Bonneville Power Administration to facilitate resource development in the Pacific Northwest. It is a step below outright plant construction, even on a turnkey basis, since the developer would need to agree to the CPA's terms and conditions. The CPA could require that a proposed plant is either priced at fully allocated cost or that the differential between market prices and fully allocated cost is returned to ratepayers.

A CPA could help streamline Connecticut's complex energy planning/procurement. Presently, the DPUC receives input from the utilities, Consumer Counsel, State Attorney General, Siting Council, etc. Yet in addition to handling rate cases and consumer complaints for natural gas and electricity, it regulates telcom, CATV and water and handles their associated rate cases and consumer complaints. It is possible that Connecticut's ratepayers could be better served if the existing structure reflected the energy agencies' strengths, i.e. rate issues (DPUC), siting (Siting Council) and plan/procure (CPA).[35]

It is desirable for a CPA to administer the procurement process. To avoid repeating the mistakes of the secret auction that led to record-high utility bills in 2007, the Illinois legislation provides a blueprint for the new agency (from Section 1-5: "Develop electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority"; "Supply electricity from the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric

[34] (20 ILCS 3855/) Illinois Power Agency Act, Section 1-57.
[35] See the state's existing energy matrices at http://www.ctenergy.org/pdf/MatricesPh1Apr08.pdf; this is the first phase of the study now underway by CAEB to look at various energy issues as mandated by the General Assembly.

cooperatives in Illinois."). Like Illinois, a Connecticut authority could be required to "Develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability" (Section 1-5) and other factors the public deems important. To the extent feasible the procurement plan could be submitted to both the DPUC and the public for review, and the procurement process monitored after the Illinois model.

A CPA could call upon the expertise of similar organizations. Staffing for the Connecticut Power Authority could draw from the state's existing energy agencies. Another domestic source of qualified individuals could be the Connecticut Municipal Electric Energy Cooperative (CMEEC), "a publicly directed joint action supply agency formed by the state's municipal electric utilities in 1976 under authority of the state's General Statutes."[36] The new Connecticut authority could also be encouraged to apply the best practices of established authorities such as NYPA, Connecticut's neighbor, and relevant federal agencies.

A CPA could be funded efficiently. Fears that a new agency might exhaust allotted start-up costs (estimated at $2 million in the State Attorney General's proposed legislation; see Appendix) could be allayed by studying the recent enabling legislation in Illinois. Unlike an ISO/RTO, a state power authority needs no outsized budget and vast bureaucracy. The Illinois Power Agency Act, for example, specifies that $25 million be paid into a trust fund and that the interest be used to cover the agency's administrative costs to the extent that the monies are not recovered through planning, procurement, and project development fees that are required by law. The new agency at present has one employee (the executive director) and an annual budget of slightly over $1.2 million (an "upfront" appropriation from general revenue funds – a loan to be repaid from investment proceeds in the trust fund).[37] Its major task is an RFP for new resources to be paid at fully embedded cost; such an RFP does not even remotely cost $1 million.

[36] "CMEEC is owned by the municipal utilities in the cities of Groton and Norwich, the Borough of Jewett City, and the Second (South Norwalk) and Third (East Norwalk) Taxing Districts of the City of Norwalk, Connecticut. CMEEC also provides all the power required by other utilities participating in CMEEC including the Town of Wallingford Department of Public Utilities, the Bozrah Light and Power Company, and the Mohegan Tribal Utility Authority." See http://www.cmeec.com/WHOISCMEEC.htm

[37] The goal was to avoid any costs being imposed on taxpayers; Connecticut could consider a similar vehicle – a user fee–funded state agency.

A systems benefits charge (SBC) on ratepayers' monthly utility bills could help to finance the CPA. Connecticut ratepayers already pay SBCs in the form of small amounts that benefit all classes of customers. SBCs pay "for programs in consumer education, worker protection, hardship cases, and nuclear decommissioning",[38] payments in lieu of property taxes, integrated resource planning expenses, etc.[39]

General principles to be considered in drafting Connecticut power authority legislation

Appendix A compares the 2007 law enacted in Illinois and the 2008 legislation proposed for Connecticut by Attorney General Richard Blumenthal.[40] Two principles stand out clearly.

The famous Illinois architect, Ludwig Mies van der Rohe, used to say, "God is in the details." The Illinois Power Agency Act is *quite specific about the agency's formation, operations, oversight, planning/procurement, and accountability.* To give one example, Section 5-122 states that the "Director of the Illinois Power Agency must have at least 15 years of combined experience in the electric industry, electricity policy, or electricity markets and must possess: (i) general knowledge of the responsibilities of being a director, (ii) managerial experience, and (iii) an advanced degree in economics, risk management, law, business, engineering, or a related field." The director is appointed by the governor and confirmed by the Illinois senate.

From the outset, *transparency is paramount*. The new agency is an arm of state government subject to open document and meeting rules, and as such is fully transparent. It reports annually to both the Illinois legislature and the governor, and its procurement plans are submitted for review and approval to the Illinois Commerce Commission. There is also provision for public review and comment. The competitive procurement process itself (Section 16-111.5) is

[38] http://www.uinet.com/uinet/connect/UINet/Top+Navigator/About+UI/Doing+Business+With+UI/Suppliers+-+Aggregators/CT+Code+of+Conduct/Suppliers+and+Aggregators+-+CT+Code+of+Conduct+-+Restructuring
[39] In 2007, CL&P's SBC was spread across approximately 1.3 million customers and UI's across approximately 300,000 customers.
[40] The Illinois Power Agency Act is far longer in content; Connecticut, however, does not require the level of financial detail in bills filed for consideration in other states.

"administered by a procurement administrator and monitored by a procurement monitor." The state treasurer oversees the agency's various funding mechanisms.

Conclusion

Today's high fuel costs have shifted the cost-effective choice in electric generating units from those with low capital costs to those with high capital costs. The traditional regulatory model used the broad base of ratepayer credit to allow cost-effective funding of high capital projects. Under electricity restructuring, this is not a viable option since ratepayers may change suppliers at will, or would be able to do so if a competitive retail electricity market existed. Connecticut unwittingly has become part of the failing experiment in administered markets. Existing costs to consumers are already significantly above marginal costs, and future costs are likely to continue to spiral out of control as New England's ISO promotes dependence on imported fossil fuels.

In designing a Connecticut-specific power authority, policy-makers might adapt the best practices of existing regional and state level power authorities in the U.S. that successfully compete with dysfunctional markets. The federal entities Bonneville Power Administration in the Pacific Northwest and the Tennessee Valley Administration in the Tennessee River area were established to take advantage of abundant waterpower and later, nuclear generation. The California Department of Water Resources, the outcome of historical efforts to control flooding in northern California, sells its excess power generation to reduce the cost of water deliveries to its customers. Closer to home, the Power Authority of the State of New York, the legal title of the New York Power Authority, serves rural electric cooperatives, investor-owned utilities, municipal electric utilities, governmental entities (e.g., the New York City Housing Authority and Metropolitan Transportation Authority), non-profit health-care, educational and cultural institutions and more than 700 businesses and industrial customers.

The IPA is the outcome of a process by which ratepayers, small towns and larger cities, state legislators, agencies, and the utilities themselves pledged to find a solution to an untenable situation. Connecticut should take heart from Illinois's successful end result, for here, too, a similar institution could provide energy at fully allocated cost rather than inflated prices from non-competitive markets, and allow the selection of more energy-independent, cost-effective and environmental options.

Appendix A: Comparison of Legislation Enacted by Illinois and Legislation Proposed for Connecticut

Subject	Legislation Enacted by Illinois	Legislation Proposed for Connecticut
Title	Public Act 09-0481 SB1592 Enrolled: AN ACT concerning regulation (also known as Illinois Power Agency Act)	Raised Bill No. 5819: AN ACT CONCERNING ENERGY RELIEF AND ASSISTANCE
Status	Signed into law August 30, 2007	2008 session introduced in February; March 11, Energy and Technology Committee issued joint favorable report; for 2009, anticipation of similar legislation submitted, depending on market prices
Name	Illinois Power Agency (IPA)	Connecticut Energy Authority (CEA)
Type	non-profit	quasi-public
Relationship to state utility regulators	"Nothing in this Act infringes upon the authority grated to the [Illinois Commerce] Commission."	Relationship to Department of Public Utility Control (DPUC) not specified
Goals and objectives	"(A) Develop electricity procurement plans to ensure 'adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for electric utilities that on December 31, 2005 provided electric service to at least 100,00 customers in Illinois. The procurement plan shall be updated on an annual basis and shall include renewable energy resources sufficient to achieve the standards specified in this Act.	"(1) procure least-cost supply-side and demand-side resources through competitive procurement processes to meet the electricity needs of all retail customers who elect service by said authority;
	(B) Conduct competitive procurement processes to procure the supply resources identified in the procurement plan.	(2) construct and operate generation facilities;
	(C) Develop electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.	(3) sell electricity at cost to distribution companies and to municipal electric utilities and cooperatives."
	(D) Supply electricity from the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois."	
Funding/Appropriations	"(a) The Illinois Power Agency Operations Fund is created as a special fund in the State treasury.	Funding is not included in state legislation; anticipation that initial appropriation from the general fund would be approximately $1 million; "the administrative costs of the contracts will be charged to ratepayers on nonbypassable charges"; CEA can "Charge reasonable fees for the services it performs and waive, suspend, reduce or otherwise modify such fees, in accordance with criteria established by the authority."
	(b) The Illinois Power Agency Operations Fund shall be administered by the Agency for the Agency's operations as specified in this Section.	
	(c) All moneys used by the Agency from the Illinois Power Agency Operations Fund are subject to appropriation by the General Assembly.	
	(d) All disbursements from the Illinois Power Agency Operations Fund shall be made only upon warrants of the State Comptroller drawn upon the State Treasurer as custodian of the Fund upon vouchers signed by the Director or by the person or persons designated by the Director for that purpose. The Comptroller is authorized to draw the warrant upon vouchers so signed and shall be released from liability for all payments made on those warrants."	
Other Funding	Illinois Power Agency Trust Fund ("the General Assembly may annually appropriate from the Illinois Power Agency Trust Fund to the Illinois Power Agency Operations Fund an amount not to exceed 90% of the annual investment income earned by the Fund to the Illinois Power Agency."); Illinois State Treasurer is custodian.	
	Illinois Power Agency Facilities Fund ("administered by the Agency for costs incurred in connection with the development and construction of a facility by the Agency as well as costs incurred in connection with the operation and maintenance of an Agency facility.")	
	Illinois Power Agency Debt Service Fund ("administered by the Agency for retirement of revenue bonds issued for any Agency facility.")	
	to cover the costs of developing/administering the procurement plan, fees are assessed on the "affected utilties" and bidders; fees to cover feasibility plans are assessed on the requesting local government, electric cooperative, etc.; fees assessed on development co-partners of Agency.	
Administration	"(a) The Agency shall have a Director who meets the qualifications specified in Section 5-222 of the Civil Adminstrative Code of Illinois (20 ILCS 5/5-222).	board of seven directors: (1) a representative of the environmental community, (2) the Secretary of the Office of Policy and Management, (3) the Commissioner of Environmental Protection, (4) the Consumer Counsel, (5) a director appointed by the Governor, (6) a director appointed by the president pro tempore of the Senate, (7) a director appointed by the speaker of the House of Representatives; no director may be a member of the General Assembly; "chairperson shall, with the approval of the directors, appoint a president of the authority who shall be an employee of the authority and paid a salary prescribed by the directors. The president shall supervise the administrative affairs and technical activities of the authority in accordance with the directives of the board."
	(b) Within the Illinois Power Agency, the Agency shall establish a Planning and Procurement Bureau and a Resource Development Bureau. Each Bureau shall report to the Director. (c) The Chief of the Planning and Procurement Bureau shall be appointed by the Director and (i) shall have at least 10 years of direct experience in electricity supply planning and procurement and (ii) shall also hold an advanced degree in risk management, law, business, or a related field. (d) The Chief of the Resource Development Bureau shall be appointed by the Director and (i) shall have at least 10 years of direct experience in electric generating project development and (ii) shall also hold an advanced degree in economics, engineering, law, business, or a related field.	

Other administration	Planning and Procurement Bureau: annually issues a request for proposals for an expert/firm to develop procurement plans and an expert/firm to serve as procurement administrator; both conduct the competitive procurement process	
	Resource Development Bureau: "conducts feasibility studies on the construction of any facility"; "for projects costing the Agency $1,000,000,000 or more, the Agency shall enter into management and operating agreements for the relevant facility or facilities."	
Benchmarks	Market-based pricing benchmarks	DPUC to "determine a price…that reflects the full cost of providing the electricity on a monthly basis and that is consistent with the approved procurement and employment plan pursuant to this section or, on an alternative basis as determined pursuant to subdivision (3) of this subsection."
Components of procurement plan	To be prepared annually by August 15 and subject to public comment before being approved by the ICC; legislation includes process, bidding procedure, contract length, filing complaints, timeline, cost recovery, etc.:	legislation includes process, bidding procedure, cost recovery, etc.
	(1) Hourly load analysis. This analysis shall include: '(i) multi-year historical analysis of hourly loads; (ii) switching trends and competitive retail market analysis; (iii) known or projected changes to future loads; and (iv) growth forecasts by customer class.'	Each distribution company must procure "electric generation services contracts in the manner prescribed in a plan approved by the department. Such plan shall require the procurement of a portfolio of service contracts sufficient to meet the projected load of the electric distribution company. Such plan shall require that the portfolio of service contracts be procured in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time. The portfolio of contracts shall be assembled in such manner as to invite competition; guard against favoritism, improvidence, extravagance, fraud and corruption; and secure a reliable electricity supply while avoiding unusual, anomalous or excessive pricing."
	(2) Analysis of the impact of any demand side and renewable energy initiatives. This analysis shall include:	Third-party analysis of contacts required
	(i) the impact of demand response programs, both current and projected;	
	(ii) supply side needs that are projected to be offset by purchases of renewable energy resources, if any; and	
	(iii) the impact of energy efficiency programs, both current and projected.	
	(3) A plan for meeting the expected load requirements that will not be met through preexisting contracts. This plan shall include:	
	(i) definitions of the different retail customer classes for which supply is being purchased;	
	(ii) monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period;	
	contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts, including but not limited to monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services; (iv) proposed term structures for each wholesale product type included in the proposed procurement plan portfolio of products; and (v) an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.	
	(4) Proposed procedures for balancing loads. The procurement plan shall include, for load requirements included in the procurement plan, the process for (i) hourly balancing of supply and demand and (ii) the criteria for portfolio re-balancing in the event of significant shifts in load.	
	(c) The procurement process set forth in Section 1-75 of the Illinois Power Agency Act and subsection (e) of this Section shall be administered by a procurement administrator and monitored by a procurement monitor"; the Act spells out the responsibilities of the administrator and monitor.	
Reporting requirements	reports annually to the Governor and the General Assembly; also ICC annually on June 15 "shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change."	reports annually to the Governor and the General Assembly; also "Not later than October 1, 2009, and biennially thereafter, the department shall conduct a contested case proceeding in accordance with chapter 54 to review the efficacy of the process of procuring contracts pursuant to this subsection including as assessment of the extent to which the standards set forth in this section are met."