The Report committee for Kevin Thundiyil

Certifies that this is the approved version of the following thesis:

Analysis of Resource Adequacy Constructs in the US and Australia and Future Paths Forward

APPROVED BY

SUPERVISING COMMITTEE:

Supervisor:

Ross Baldick

Varun Rai

Analysis of Resource Adequacy Constructs in the US and Australia and Future Paths Forward

by

Kevin Thundiyil, B.S.E.E

Report

Presented to the Faculty of the Graduate School

of the University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Engineering

The University of Texas at Austin

May 2011

Acknowledgements

The author would like to acknowledge the assistance of Professors Ross Baldick and Varun Rai for their suggestions and edits to the report. The comments and feedback of the professors were essential to the development of the ideas presented in the report.

May 3, 2011

Abstract

Analysis of Resource Adequacy Constructs in the US and Australia and Future Paths Forward

Kevin Thundiyil, MSE

The University of Texas at Austin, 2011

SUPERVISOR: Ross Baldick

Deregulation of the electricity industry has altered the investment landscape for new resources. Multiple resource adequacy constructs are in use today around the world and represent diverging opinions of how much interaction regulators should have on the procurement of new resources. The report compares the resource adequacy constructs in Australia, Texas, California and the Northeast of the United States and discusses the future of resource adequacy. The report concludes that a hybridized construct that blends the high offer caps of energy-only markets, the prescriptive nature of resources in capacity markets and a strong price-responsive demand will likely be the future of resource adequacy.

Table of Contents

List of Tables viii

List of Figures ix

List of Acronyms x

Chapter 1: Introduction 1

Defining Resource Adequacy 1

Resource Definition 3

Chapter 2: The Need for Assuring Resource Adequacy 6

Retirements 6

Outages 6

Load growth 6

Investment risk 6

Chapter 3: The Constraints of an Imperfect World 8

Price Caps 8

Inelastic Demand 9

The Physical Nature of the Electric Grid: Resource Siting and Market Power 10

Chapter 4: Solutions to Resource Adequacy 12

Resource Adequacy for Bundled Utilities 12

Scarcity Pricing: If You Price It (High Enough) They Will Come? 13

Capacity Markets 15

SMD: Was its RAR Worse than its Bite? 15

Supply and Demand Curves 17

Chapter 5: Case Studies 19

Regions without Centrally-Organized Capacity Markets 19

ERCOT 19

Structure 20

Market Power Mitigation 21

Evaluation 22
CAISO....24
Structure....24
Evaluation 25
Australia....26
Structure....26
Evaluation 27
Regions with Centrally-Organized Capacity Markets 28
NYISO 29
Structure....29
Evaluation 30
ISO-NE 31
Structure....31
Evaluation 31
PJM 32
Structure....32
Evaluation 33
Chapter 6: Future of Resource Adequacy....36
Different Strokes for Different Folks....36
Price responsive loads....36
Changes in the Resource Mix 38
Chapter 7: Conclusions....39
Appendix....41
Bibliography 43

List of Tables

Table 1: Feasible resources within the resource adequacy context..................5

Table 2: Summary of Regions and Resources Adequacy Constructs 13

Table 3: Comparison of Estimated Costs and Revenues for a New Combustion Turbine in NYISO in 2009 30

Table 4: 2009 PJM Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed kW-year) 34

Table 5: Summary of Load Reductions through the PowerCentsDC Program41

Table 6: Summary of Savings Achieved by PowerCentsDC Customers........42

List of Figures

Figure 1: Timeline of Operations versus Planning 3

Figure 2: Generic Supply and Demand Curve for a Capacity Auction 18

Figure 3: Example of the Texas Net Peaker Margin concept, assuming $500/MWh is the lower offer cap...22

List of Acronyms

AEMC	Australian Electricity Market Commission
AEMO	Australia Electricity Market Operator AEMO
CAISO	California Independent System Operator
CONE	Cost of New Entry
CPT	Cumulative Price Threshold
CPUC	California Public Utility Commission
ERCOT	Electric Reliability Council of Texas
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
ISO/RTO	Independent System Operator/Regional Transmission Operator
ISO-NE	Independent System Operator of New England
LMP	Locational Marginal Pricing
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MMBTU	One million British Thermal Units
NPCC	Northeast Power Coordinating Council
NYCA	NYISO Control Area
NYISO	New York Independent System Operator
OECD	Organization of Economic Co-Operation and Development
PASA	Projected Assessment of System Adequacy
PJM	Pennsylvania-New Jersey-Maryland Independent System Operator
PUCT	Public Utility Commission of Texas
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RERT	Reliability and Emergency Reserve Trader
RFP	Request for Proposals
RO	Reliability Options
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard

Chapter 1: Introduction

Restructuring of the US electric industry has brought on a broad set of challenges for utilities, investors, and regulators. One of these challenges includes how and when new resources are brought online. The issue, typically referred to as resource adequacy, historically was (and in some areas is still) addressed through centralized resource planning. In contrast, centralized power markets lack such command and control mechanisms to develop new sources and have instead developed a variety of quasi-market-based tools over the last 10 years. This report will give an overview of these tools and provide analysis into what has been effective, why certain solutions have been effective and what the future of resource adequacy will bring.

DEFINING RESOURCE ADEQUACY

The term resource adequacy is a broad term that has multiple interpretations. Some states and regions use terms such as *planning margins*, *capacity margins* or *capacity requirements*; separately, the term *reserve margin* is also used but in the context of shorter operational timeframes. Thus, for the purposes of this report, a set of criteria will set bounds on the resource adequacy problem by limiting the definition based on a set of three criteria: what timeframe constitutes the resource adequacy problem, what resources can be included in addressing resource adequacy, and what is the actual measure of adequacy.

First, a timeframe must be selected that defines the point at which a need is determined and when the resource can reasonably be expected to be on-line. This determination will bind the problem to either short-term (2 to 5 years) or long-term (10 years) planning expectations. Generation planning typically takes place in the 2 to 5 year timeframe since siting, permitting and construction of power plants usually takes on that order of time. Shorter timeframes are possible for smaller power plants such as diesel or even possibly for natural-gas combustion turbine plants. Nonetheless, providing transmission access remains the primary concern despite the availability of a relative quick power plant construction process.

Generation planners thus have a general timeframe for when they should expect a resource to come on-line, but how do they exactly know when new resources are needed? In the operating time frame (hours to weeks to months ahead), utilities and system operators will assess whether there is enough generating capacity to meet load (see Figure 1); if not, resources will be called up out of maintenance, prevented from going into overhaul or even pulled out of mothball status if the situation is dire and foreseen early enough. In the US, load curtailment is only seen as a last-resort tool such as when sudden changes in system conditions require immediate action and more specifically, when available generation and load-based resources are exhausted. Thus, in the operating timeframe, the safety in which the system operates can be seen as how much available resources (generation and load-based) exceeds expected system load e.g. the greater the amount of resources, the greater the margin of operational reserves[1].

These operating measures are not sufficient indicators of reliability, however. All plants have a rate at which they trip off or fail. The data is reported to the North American Electric Reliability Corporation (NERC) which provides quadrennial updates. A variety of software tools used in the industry such as PROMOD and GE MAPS take this data along with load flow base case information and project the likelihood that generation does not meet load e.g. the likelihood that load will be lost since there is insufficient generation[2]. The results from these studies give generation planners an idea of how much additional resources are needed to keep reliability up to a certain level e.g. keep outages to at most 1 day in 10 years, which is the typical industry standard. Thus, to be in-line

[1] Federal reliability standards require a minimum amount of operating reserve to be on-line and ready to be dispatched at all times, equal to the largest unit in a balancing authority or reserve sharing group.

[2] The NERC data only includes power plant data and not load-side resources. As policy makers call for increased use of loads as resources and parity in treatment with traditional power plants, similar metrics for load will need to be tracked and reported. ISO-NE's Market Rule 1 §III.13.1.4.3. "Measurement and Verification Applicable to All Demand Resources" has a detailed set of criteria for demand resources that qualify as a capacity resource.

with the perspective of the generation planner, this report will use the LOLE or loss of load expectation as the measure of resource adequacy.

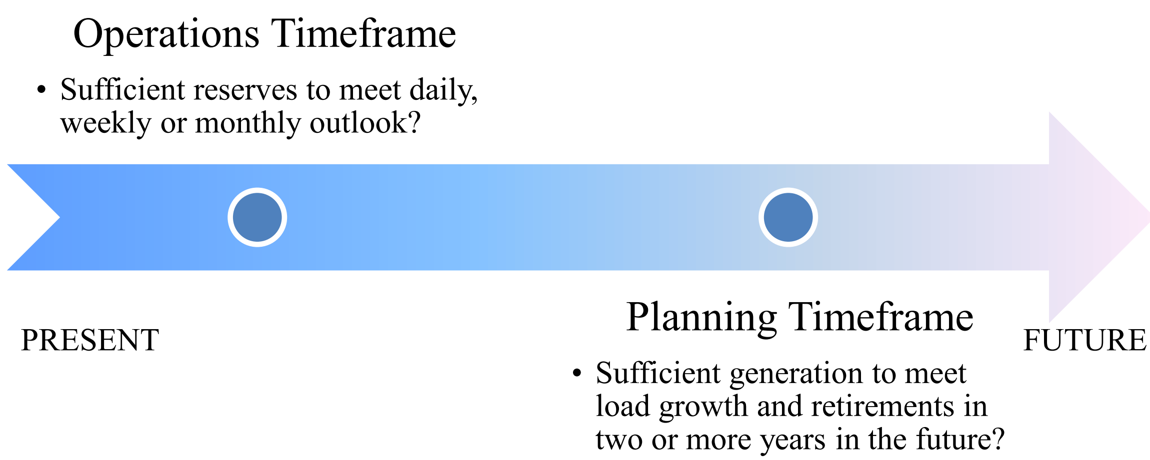

Figure 1: Timeline of Operations versus Planning

RESOURCE DEFINITION

One of the foremost peculiarities about the electric market, compared to markets in general, is the aspect of mostly inelastic demand. The power industry has been fostered by a regulatory sentiment that electricity is an essential resource and must be provided at all times. Modern economies are run on the availability of electricity and thus such perspectives are certainly founded.

Regulators are now more open to the possibility of exposing load to price signals, be they real-time wholesale prices, less dynamic proxies of such signals or even a pre-determined number of peak-time pricing events throughout the year[3]. The behavior of residential retail consumers in response to price signals, of any sort, is not known with full certainty, however. Thus, parity treatment of price-based demand-response with generation

[3] Time of use rates for industrial customers have been around for decades; however, pilot programs such as the PowerCentsDC program(see Appendix for more details) indicate state regulators are slowly opening up to the idea of dynamic pricing for consumers.

resources (with roughly known characteristic such as forced outage rates, bids, etc) is an argument that cannot be made with full certainty given current data and operational practices.

Price-sensitive residential loads, since they are dependent on the unpredictable behavior of end-users cannot feasibly be included as a resource since system operators cannot have certainty on their operation at any given time[4]. Utility load forecasting has relied on a variety of software models to predict system loads. As the amount of price responsive load grows, such loads will be another variable system operators and utilities will have to add to the software models. Fortunately, the uncertainty of price responsive load will typically be in the utility's favor in that demand will likely drop and not exceed the utility's generation portfolio, with the exception of extremely hot days when demand is likely not as elastic as the utility would have expected; those unexpected purchases of electricity would be made from the wholesale market, which would reflect the increased marginal cost of generation. Predicting the price-responsiveness of load will become an art itself much as determining load curves today based on the variables of weather, holidays, and other factors. With the advent of smart meters and the possibility of dynamic pricing and the subsequent utility experience with customer time-of-use data, utilities will be able to leverage such knowledge and tools as a resource. The future of dynamic pricing and smart meter issues are discussed later in the report.

Per usual utility practice and through regulatory mandate, demand-side projects including energy efficiency[5] are counted towards the resource portfolio in a utility's footprint[6];

[4] Large industrial users will typically participate in the market or have a contract to reduce loads during certain periods. Such options for incentivizing demand reduction are not usually available for residential customers.

[5] Energy-efficiency projects typically include state or municipally-approved projects to fund customer rebates on higher-efficiency appliance purchases. Such projects are common for vertically-integrated utilities. Utilities can estimate the amount of load reduction by the number of participants in the energy efficiency program.

[6] In the Hawaii State RPS mandate for years up to 2030, energy efficiency can be counted toward the state goal however, for years after 2030 energy efficiency cannot be counted.

however, these sorts of resources are netted against the total load and not with the generation portfolio. Thus, resource adequacy is a ***temporal measure*** that may include certain resources and exclude others depending on the timeframe in question. For instance, a planned generator that has signed interconnection agreements with the utility or system operator will not be counted towards any sort of near-term adequacy measure, but only towards a future scenario used in planning models.

For the purposes of this report and in-line with the bounds already outlined, the resources considered to be part of resource adequacy will include those resources expected to come on-line in the two to five year timeframe and may include resources such as conventional generation, renewable generation (discounted by an appropriate capacity factor) and load-side resources, a group that may include load aggregation programs that participate in peak shaving events (e.g. resources that have signed agreements with utilities).

Resource Type	**Description**
Conventional	Combustion or steam generation, hydroelectric plants
Intermittent	Wind and solar plants, discounted by a capacity factor
Load-side	Peak shaving loads, loads contracted with the utility to shut off or lower when needed, energy efficiency projects

Table 1: Feasible resources within the resource adequacy context

The preceding discussion has bound the resource adequacy definition to the following: generation and load resources that can be procured in the 2 to 5 year timeframe that limit the chance of an outage to less than one day in ten years (or some other reliability criteria).

Chapter 2: The Need for Assuring Resource Adequacy

A definition of resource adequacy presents only a partial view of the issue; however, the underlying conditions that drive the problem must also be described. Four primary drivers, discussed below, require pro-active planning and measures to ensure reliability.

RETIREMENTS

Since the 1970's and introduction of the Clean Air Act, coal-fired resources have been required to meet air quality restrictions on sulfur dioxide and other particulate emissions. These restrictions have required the addition of flue gas desulphurization technology to existing units; those units that have found the addition of such environmental upgrades too costly are forced to retire[7].

OUTAGES

The rate of unit outages is part of the generation planning study. These statistics include the outages that are caused by equipment failures and fuel interruptions.

LOAD GROWTH

The growth in electric demand is tightly correlated to economic factors such as GDP growth. Periods of slow economic growth imply low or less electric demand growth while strong periods of economic growth will imply high electric demand growth. On average, electric demand is assumed to grow at around 2% per year. As load is put on-line, additional resources are required to fill the gap between existing demand and future demand.

INVESTMENT RISK

This is not a resource adequacy issue per se, but a problem in generation investment which affects the development of resources e.g. are the market signals (be they in an

[7] More recently, recent USEPA regulations on mercury emissions from coal-fired power plants could force retirements of 50 GW of capacity (Credit Suisse, 2010).

energy-only market or capacity market) providing adequate signals to investors to indicate the relative need of resource development.

Chapter 3: The Constraints of an Imperfect World

The focus of this report is on those areas that participate in organized electric markets, but not only those areas that have a central resource adequacy planning mechanism. Independent of the market structure imposed, limitations exist that impose conditions that impede true market signals. As discussed below, some of these limitations are imposed as part of regulatory safety nets. Other limitations represent the problems in infrastructure expansion such as limitations in the physical network and certain solutions considered uneconomic for the time-being.

PRICE CAPS

In electricity markets, the price of electricity is based on the marginal offer price of each of the individual generators, whereby generators with the lowest offers are dispatched first and then the next highest are dispatched until total demand is met by the total number of on-line generators. The higher the demand, the higher the marginal cost and offers of electricity; thus peak load will be met by generators that are the least economic of all units[8]. Regulators have adopted price caps in electric markets to protect end-users from two things. The first is periods of extremely high prices. By limiting the height to which prices can rise, end-users are not exposed to the tremendous prices to which prices can rise to during shortages. The second reason is limiting the effects of market power; ideally, no generator can influence the movement of prices by deciding to raise or lower the plant's output, however when there is limited supply into an area, prices can be manipulated. Market power is discussed in further detail later in this section.

These caps range from $12,500 AUD/MWh[9] in AEMO to $1,000 US/MWh in the PJM ISO. (Joskow, 2007) provides a good discussion on how to set the appropriate price cap, most notably based on the concept of value of lost load (VOLL); such metrics are

[8] High costs could be attributed to limited number of run-time hours due to environmental restrictions, high marginal costs, as well as revenue models and bidding strategies of power plant investors, which set the price of peak generators high.
[9] Roughly $USD 12,500/MWh

difficult since it is difficult to gauge the exact value consumers have for load in real-time. However, while such a number may not be physically realizable, regulators can estimate what the value should be.

An artifact of a low price cap imposed on the electric market is that electric generators are prevented from recovering the full cost of their investment. (Adib, Schubert, & Oren, 2008) note that peaking generators only recover costs for capital investment during peak load periods, e.g. when the price of electricity reaches peak levels[10]. Thus, preventing the price from reaching the market-induced price restricts generators from recovering the full costs of their assets. Dr. Roy Shanker coined this lost revenue "missing money" since it is the money that generators are missing (Shanker, 2003).

INELASTIC DEMAND

Members of OECD countries can expect their electricity to be on for most of the time out of the year. Expectations have been built such that electric demands are met by the utility and that the utility's generators will work to meet those demands. Such expectations are plausible in perfect worlds; however there are many occasions even in developed countries where generation cannot always meet demand. Regulators have built a philosophy around this expectation and the concept of cost-of-service utility recovery follows directly from this philosophy e.g. the regulator approves whatever rate the utility needs to economically supply electricity to all its users at all times. Regulators will not expect demand to stop using electricity during electricity shortages and thus typically do not have a credit mechanism for such behavior[11]. While regulators may be somewhat skittish to the concept of dynamic pricing, perhaps more significantly, the infrastructure

[10] Baseload generators can typically recover some costs during periods when they are fully dispatched.

[11] However, demand response and energy efficiency programs are ways to reduce loads. Demand response will be discussed further in the paper.

and technology that takes advantage of lower cost, for example, off-peak electricity is not widely available commercially[12].

The Physical Nature of the Electric Grid: Resource Siting and Market Power

Ideally, transmission lines and generators could be built at any location to provide enough transmission access and generation such that flows between generators and loads are never constrained. Unfortunately, transmission is difficult to build and generation also suffers from siting restrictions. These physical constraints on siting result in several things: load pockets, deliverability issues and market power.

Load pockets are areas that are limited in how much power they can import from outside areas. For example, imagine an area that is surrounded by mountains with the exception of one main corridor; the area has only one feasible transmission route since building transmission over the mountains may have been found to be uneconomic[13]. The situation presents multiple problems. First, due to air quality restrictions (lack of free movement of air), the area presents severe air quality restrictions to power plants, thus construction of power plants and operating power plants will be limited. Second, the electric reliability of the area is at risk due to the single transmission corridor; in addition, import capability into the area is limited e.g. lack of multiple transmission paths restrict the total amount of power available.

While the earlier example may be in the extreme, cases of market power are much more difficult to prevent and mitigate. Measures such as the Herfindahl-Hirschman Index

[12] Infrastructure e.g. smart meters are becoming more popular but loads that capitalize on lower cost electricity such as ice storage air-conditioning, electric vehicles, “smart” appliances and other “storage”-type technology has not been widely adopted.

[13] Generators that attempt to sell into such load pocket areas are typically not allowed to use market-based prices and instead must abide by cost-of-service rates.

(HHI) and pivotal supplier tests are used in the electricity industry to understand when a producer has the ability to exert market power.

Market power is the ability of a generator to influence prices. Sufficient amount of generators in a single area would guarantee no generator can withhold supply and raise prices. (Wen, Wu, & Ni, 2004) argue that electricity markets rarely exhibit pure competition and more often resemble oligopolies. Coupled with the barriers to entry (such as those mentioned above) and despite the potential for high-prices that would lure investment, the amount of supply is below the social optimum level of demand.

Together, these physical limitations prevent the ideal and thus stop-gap measures are required. Possible measures include price caps and restrictions on who are qualified to receive market-based rates.

Chapter 4: Solutions to Resource Adequacy

The previous sections attempted to lay out an understanding of why there is a resource adequacy issue. The next section of the report will focus on the solutions to the problem. As will be seen, different histories and philosophies led to different solutions. Tightly integrated areas will see strong central planning methods while areas with political constituencies that look more favorably on market forces and less command-and-control will see corresponding methods.

RESOURCE ADEQUACY FOR BUNDLED UTILITIES

Vertically-integrated or bundled utilities have typically planned for future resources (demand-side as well as supply-side) through the Integrated Resource Planning (IRP) approach (Lesh, 2009). A utility would present to the regulator an expectation of loads and a variety of generation plans, ranked by economics, to meet it. The multiple scenarios presented by the utility would consider different environmental policies that are approaching as well as fuel price expectations and a range of demand response resources. A utility will put forward a capital expansion proposal based on the study and the regulator would approve the rates that fund the proposal. A public version of the IRP would be published, thus allowing the public to comment on the approach and question any assumptions. Any costs that the regulator did not believe were justifiable were removed and the proposed electric rate was subsequently lowered. Such cost of service regulation is still the norm in municipally-run electric utilities throughout the US and in regulated states throughout the Northwest, Southeast of the United States and the Midwest, e.g. those utilities that are still vertically integrated and regulated by the local or state jurisdiction entity.

The Energy Policy Act of 1992 first mandated the use of IRP; however, with the emergence of deregulated utilities, the IRP is relied on less while planning coordination has moved to the ISO/RTO for the most part. Transmission expansion is typically coordinated by the ISO/RTO or regionally amongst the ISO/RTOs. Generation planning in ISO/RTOs is for the most part handled by the market, but as will be seen below the investment signals provided to the market differ amongst the ISOs/RTOs.

Non-IRP Mechanisms for Resource Adequacy

The section below summarizes the resource adequacy measures in use today. Some such as the scarcity pricing mechanism are not direct RA measures but rather a system that ensures market signals are sent to investors with the net result being, in theory, that new resources are developed when needed. Table 2 below summarizes the regions studies in the report.

Region	RA Construct	Price Cap	Experience Summary
ERCOT	Energy-only	$US 3000/MWh	No current issues with capacity
Australia	Energy-only	$AUD 12500/MWh	No current issues with capacity
CAISO	Bilateral contracts	$US 500 /MWh	No current issues with capacity
NYISO	Capacity Market	$US 1000 /MWh	No current issues with capacity
ISO-NE	Capacity Market	$US 1000 /MWh	No current issues with capacity
PJM	Capacity Market	$US 1000 /MWh	No current issues with capacity

Table 2: Summary of Regions and Resources Adequacy Constructs

SCARCITY PRICING: IF YOU PRICE IT (HIGH ENOUGH) THEY WILL COME?

In so-called "energy only" markets, there are no mechanisms to determine the appropriate amount or level of resource adequacy. Neither regulators nor system operators determine the appropriate level of reserves since the price from the energy market is a direct translation of the relative need of additional resources as well as the appropriate indicator of incentives available to investors. When a resource shortage occurs (e.g. available reserves have declined), prices should rise to a point that reflects the value of lost load (VOLL). Cramton & Stoft provides a range of VOLL from literature from $2000 to

$50,000 to a staggering $266,666/MWh[14]. Kirschen notes that surveys are performed to determine what an average consumer would pay to forgo an outage. Several problems from the survey approach arise including exaggeration of values as well as applying a value to a wide group of users that may not share similar preferences. The temporal significance of VOLL e.g. one's value of electricity today may be marginal compared to getting ready for an important job interview in the morning[15]. In addition, the concept of VOLL is somewhat tenuous when load cannot respond to price.

System operators may intervene and imbue certain characteristics to the level of demand, e.g. voltage reductions or activation of voluntary load shedding programs[16]; however those are not the genuine actions of demand (e.g. in response to a price spike) as they are based on the preservation of grid reliability by the system operator.

Energy-only markets require certain assumptions. First, it requires there are generators uncommitted and willing to sit out for most of the year and be available during scarce conditions—very likely rare considering financing such a project would be difficult. Second, resources (as well transmission access) cannot and will not appear instantaneously when system conditions push prices reflective of the scarcity conditions. Ideally, demand would respond when scarcity conditions occur, however there are few situations where such opportunities currently exist due to that lack of dynamic pricing.

---

[14] Cramton and Stoft refer to the latter value as the interpretation of "engineers." It is not clear who the paper is exactly referring to in this instance. However, the significance of an arbitrary number is certainly problematic.

[15] Proper hygiene requires sufficient amounts of lighting and heating; most will likely pay a huge sum to keep electricity on for such purposes. Value of lost load becomes value of lost income.

[16] There are possibly perverse incentives for load to raise its load profile during the load data collection period and resume normal (lower) usage outside of that period. System operators would be rewarding users for such perverse behavior—and more importantly get drastically less reductions in load than it expected. Real-time metering would reduce such uncertainties [See Appendix on how the PowerCentsDC program dealt with the problem]. (Wolak et al, When It Comes to Demand Response, Is FERC its Own Worst Enemy?, 2009)

If market monitoring is not adept at detecting oligopolistic behavior then excessive costs will be borne by consumers over some prolonged period of time.

Effective energy-only electricity markets require a functioning demand response. The high prices that occur on the spot market during scarcity are likely rare instances, but are still borne by consumers that have no option but to pay whatever the wholesale market reflects[17].

CAPACITY MARKETS

Before discussing capacity markets in detail, this report will look briefly at FERC or the Federal Energy Regulatory Commission's opinions and decisions on resource adequacy in organized markets. The Commission must approve any proposal on resource adequacy in an organized market, thus the history of FERC thought on the issue represents the balance of ideas[18] in the debate to find resource adequacy solutions over the past decade.

SMD: Was its RAR Worse than its Bite?

Towards the beginning of the 21st century, FERC envisioned a massive plan to coat the entire US in organized electric market sauce. The plan, officially called Standard Market Design or SMD[19], proposed several requirements[20], however the one of pertinent interest is the requirement to establish long-term resource adequacy measures or RAR (Resource Adequacy Requirement).

---

[17] An hour of high prices out of the whole year will not represent a major increase in bills for most consumers, prolonged periods of high prices will however be reflected.

[18] FERC's overriding mission is to approve proposals that are just, reasonable and not unduly discriminatory. When FERC actions fall short of this, the circuit courts ensure such treatment is made.

[19] Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 100 FERC ¶ 61,138 (2002).

[20] SMD was received by certain utilities as being too prescriptive and polarized the political will. Strong political voices from the Southern states railroaded the proposal and SMD was never heard from again, with the exception of the organized markets in the East and California, which already incorporated nearly all of the SMD concepts.

At the heart of the SMD RAR was a belief that energy-only markets do not effectively develop new resources. LSEs become dependent on the investment decisions of others and such behavior thus cultures a trend of underinvestment and high prices. SMD proposed placing capacity purchase obligations on LSEs. Additionally, penalties would be imposed on LSEs for not making capacity purchases or not curtailing load during emergencies. While curtailing load during shortage periods appears to be a good idea, there currently is no means for an LSE to shut-off individual retail customers[21].

It could be interpreted that SMD was agnostic towards the specific resource adequacy measure an ITP implemented[22]. FERC likely understood that each area had legacies that supported specific mechanisms. However, if stakeholders presented an argument that positioned the incumbent system as being unjust and unreasonable, then FERC has an obligation to order a new system be developed.

In the capacity markets, the system operator determines the amount of reserves individual LSEs must carry based on a reserve requirement above the peak load the LSE is forecasted to serve at some point in the future e.g. the *obligation* period. The obligation period is defined as some point in the future at which the LSE must cover its capacity obligation; for instance, an LSE may be required to purchase capacity based on its load three years from now. The *procurement* period is defined as the months leading up to the obligation period; this is the time that the LSE must enter into contracts or arrange for purchases from the centrally-administered auctions; from the preceding example, this would be the time leading up to that three year point.

---

[21] In states with competitive retail access, customers on a single distribution feeder could be contracted with different LSEs, some of who have sufficiently purchased capacity and others who have not. Actions to curtail load by disconnecting the entire feeder would be unfair to those who have contracted with a compliant LSE. Smart meters may provide such capability in the future.
[22] "…through self-supply, contracts to purchase generation, biddable demand or other demand response program." See id.

The load ratio share of reserve allocation is a problem since many unbundled areas allow retail choice; consumers can switch LSEs at any time[23], thus the required reserve that a LSE must carry may fluctuate over time. Changes in a LSE's obligation can be handled in auctions or adjustment periods that are closer to the obligation period.

Centrally-organized markets such as those in the Eastern part of the US, will define a certain amount of additional capacity needed in the obligation period which is typically the next three years. The process to determine the needed amount of capacity is somewhat similar to the method a traditional generation planner in a vertically integrated utility would follow. Armed with a load forecast for three years in the future as well as a criterion to determine how much additional generation (if any) is needed to maintain reliability e.g. LOLE[24], planners in centrally-organized markets such as NYISO or PJM will run models in production cost simulation software and determine the needed amount of capacity for the obligation period. Due to transmission constraints within an ISO/RTO, the central planner will often determine how much capacity will need to be procured within a specific transmission zone; these zones are typically drawn based upon the physical footprints of member utilities. LSEs will need to procure a certain amount of capacity within their zone and may cover the rest from resources outside of their zone.

Supply and Demand Curves

To determine the market clearing prices for capacity, market administrators need to create demand and supply curves. Separate curves can be defined for load zones, so as to require certain amounts of locally-procured resources. The intersection of the supply and demand curves determines the market clearing price for capacity, see Figure 2.

---

[23] Like mobile phone contracts, there may be a penalty for exiting a contract before the term has expired.
[24] A typical LOLE criterion is 1 outage in 10 years.

To procure the right amount of capacity, demand curves must be downward sloping since additional capacity beyond the desired point should not be incented. The slope of the demand curve is based on three points: first, the curve is typically capped at a point equal to one and one-half times CONE or cost of new entry; second, the needed amount of reserves (the administratively-determined installed reserve margin or IRM) is set to equal CONE and finally, for a large amount of capacity above the desired level (e.g. 120% above IRM) has a zero dollar value.

Supply curves are created based on the offers made by resources. The definition of a resource depends on the regional criteria for resource adequacy, but will typically include generation or load-side resources. In the figure below, the clearing price of capacity is below CONE indicating the amount of resources available has pushed the cost of capacity below the cost of a building a new combustion turbine, which is typically the basis for CONE.

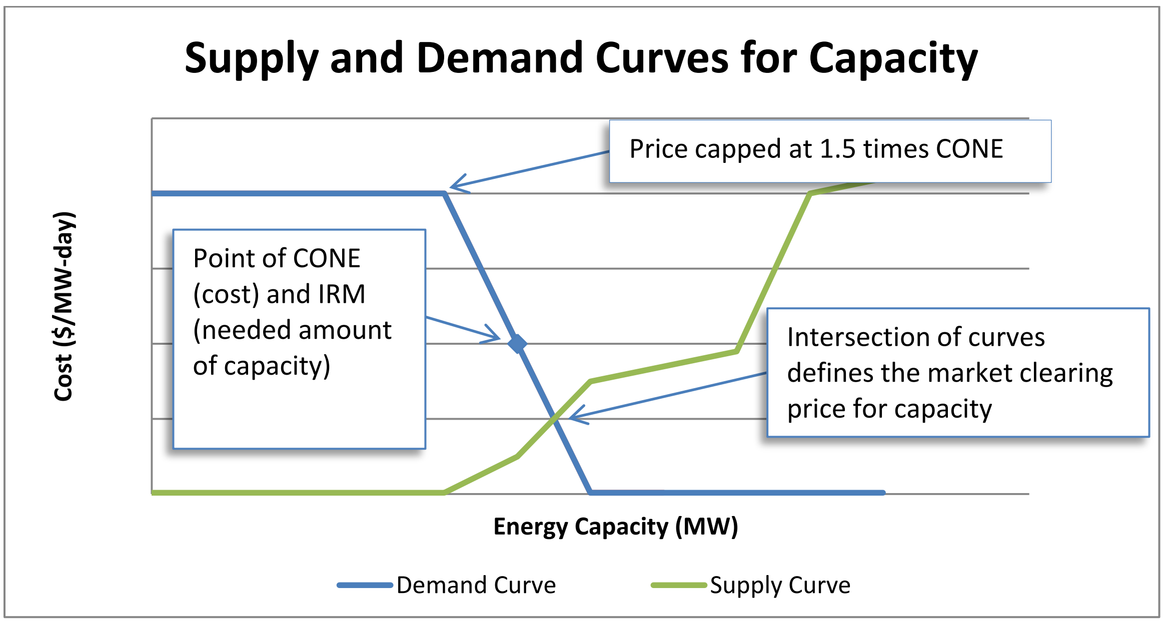

Figure 2: Generic Supply and Demand Curve for a Capacity Auction

Chapter 5: Case Studies

We know turn our attention to how resource adequacy is treated in physical power systems. The case studies below are divided into regions with and without formal capacity markets. A brief introduction to each region is given and an evaluation of the capacity construct is then provided. The primary means to evaluate the individual resource adequacy constructs is the concept of net revenue. Investors would presumably only pursue investments for which they would get remunerated (energy sales minus variable production costs). For the most part, market monitors in each region provide a net revenue analysis for new generators[25]. The cost of new generation (typically a combustion turbine) varies across the US, so net revenues should only be seen in the context of the region in question. Excessive or severely low revenues may indicate problems with market rules (Potomac Economics, 2010). While one would always hope that prudent investments are remunerated, excess capacity or low loads may contribute to depressed revenue. Such market signals are appropriate as it indicates the relative need (or in the case of low revenues, lack of need) for capacity. However, when the market does not indicate the need for additional capacity when the system is actually in need, then that indicates a problem.

REGIONS WITHOUT CENTRALLY-ORGANIZED CAPACITY MARKETS

ERCOT

Through a series of regulatory proceedings and court settlements as well as a curious interpretation of interstate commerce, Texas and its electric utilities have been largely outside the purview of FERC[26]. The introduction of the Energy Policy Act of 2005 however brought ERCOT and its member utilities under FERC jurisdiction with respect

[25] Several ISO/RTOs have contracted the services of Potomac Economics, Ltd to provide independent evaluation of the market. The set of analysis that Potomac Economics provides is consistent over the set of ISO/RTO clients.

[26] For an expanded discussion on the jurisdictional history of ERCOT, see (Fleisher, 2008)

to Section 215 of the Federal Power Act[27]. While FERC regulates the transactions across the DC ties between ERCOT and its neighbors, FERC has no authority on the workings of the ERCOT market and remains completely under the jurisdiction of the Public Utility Commission of Texas (PUCT).

Structure

ERCOT currently operates a day-ahead market and real-time market with locational marginal pricing (LMP)[28]. The ISO also operates a simultaneous clearing auction for ancillary services[29].

With regards to capacity, there is no formal purchase obligation placed on the retail entities. ERCOT stakeholders decided to remove the mandatory minimum reserve margin requirement in 2000, thus formalizing ERCOT's declaration as an energy-only market (Siddiqi, 2007). ERCOT does however calculate a target planning reserve and raised the target to 13.5% in November 2010. The ISO also publishes several reports that give investors a perspective on the need for additional resources. The Statement of Opportunities (SOO) is published annually and provides investors and market participants a long-term (5 to 10 year) projection of resources and loads. A Projected Assessment of System Adequacy (PASA) is also published that gives investors and market participants a short-term (one week) and medium-term (three year) outlook as well[30]. The shorter-term reports provide greater insight into the ancillary service requirements, projection of zonal loads as well as transmission constraints. (Siddiqi,

[27] Mandatory electric reliability standards.

[28] LMP is a pricing concept that establishes specific pricing levels for individual nodes on a power system. LMP prices reflect the marginal costs of generation at different points on the system as well as the transmission constraints that limit the flow of power between different nodes. One of the strengths of LMP is that it directly indicates where new resources should be built as higher prices indicate a need for new resources.

[29] Ancillary services include reserves that are needed in the operations timeframe, see Figure 1. For example, if a generating unit trips off line, reserves procured under the ancillary services market fill in the gap caused by the loss of the unit.

[30] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 25.505 (Vernon 1998 & Supp. 2005) (PURA).

2007) notes that the Texas energy-only market reduces any benefits a free-rider[31] may observe during scarcity; the high-prices from the spot market such an entity is exposed to during scarcity will induce investment and forward-contracting[32].

Market Power Mitigation

Since the Texas electricity market relies on energy prices to induce behavior on the part of investors and market participants, addressing the potential for market power and scarcity pricing must be addressed. Unmitigated market power indicates a lack of new market entrants and results in higher energy prices. The PUCT designed market rules to work with the energy-only concept. Termed the Scarcity Pricing Mechanism, the PUCT uses two methods to mitigate prices: a dollar cap on the price of energy offers and a cap on the annual "peaker net margin." In addition, the PUCT does not actively monitor entities that control less than 5% of the installed capacity in Texas[33]; this exemption, known colloquially as "small fish swim free" assumes small entities cannot exert ERCOT-wide market power, but does not rule out the possibility of local market power.

Price caps, as discussed earlier, are a basic tool to limit market power. If the spot price of energy is limited to a certain level then resources are prevented from capturing unlimited profits. In Texas, the offer cap on energy is set at $3000/MWh. Such a cap is high when compared to other ISO/RTOs around the US; however, the Eastern US markets have capacity markets that are designed to capture the "missing money" created from a low price cap.

---

[31] In this context, a free-rider would be a load-serving entity that benefits from the investment decisions of others and does not actively engage in forward-based contracts or other hedging instruments.

[32] Retail entities can certainly declare bankruptcy and avoid the costs of paying such obligations. Texas electric retailer, Texas Competitive Energy chose to not be covered with forward contracts and bought all its energy from the ERCOT spot market. After one year, the organization sought bankruptcy protection (Dallas Business Journal, 2003).

[33] Texas Senate Bill 7 also limited the amount of installed capacity that any single entity can own to 20%.

The second part of Texas' market power mitigation involves calculating the revenues of a dummy peaking generator. If the annual revenues of the generator exceed $175,000[34] then the offer cap in ERCOT is reset to the low system offer cap, see Figure 3. The low system offer cap is the higher of $500/MWh or 50 times the price of natural gas at the Houston Ship Channel. The peaker net margin should reflect the annual fixed costs of a marginal generator (natural gas peaker).

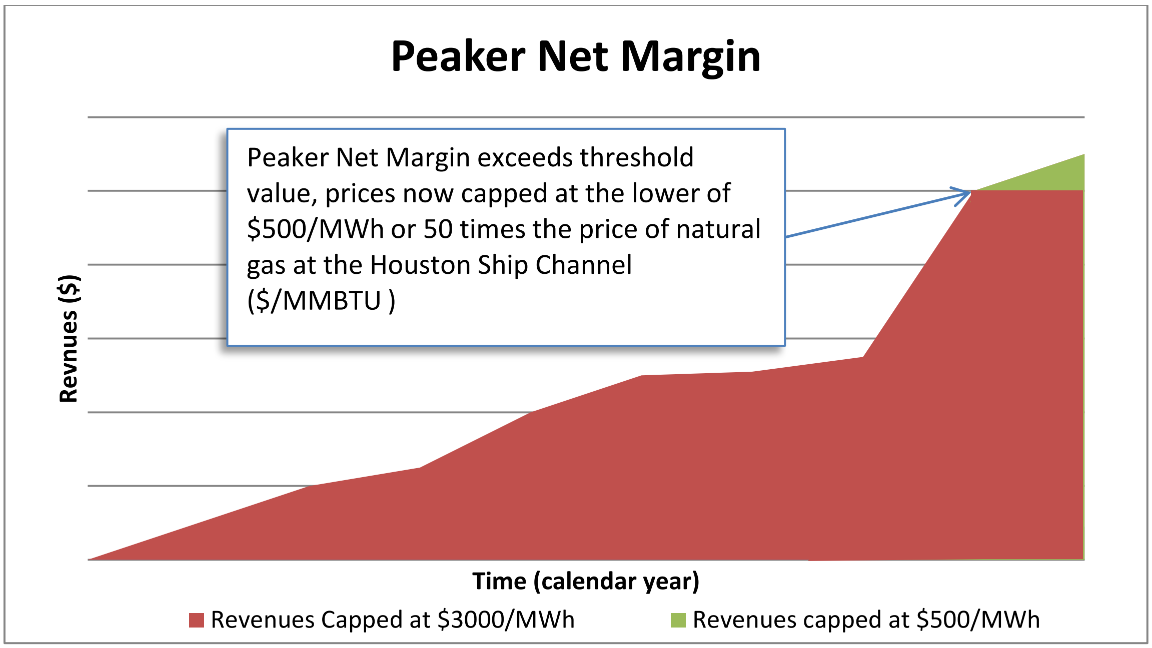

Figure 3: Example of the Texas Net Peaker Margin concept, assuming $500/MWh is the lower offer cap

Evaluation

Outside the purview of national regulation and bucking the trend of a capacity market, ERCOT is truly a lone star. Let us look deeper into the issues mentioned earlier and assess the rules that govern the ERCOT market.

[34] Revenues are calculated as the difference between the ERCOT average LMP price and 10 times the price in $/MMBTU of natural gas at the Houston Ship Channel. The 10x factor is the equivalent of a 10,000 BTU/kWhr electric generator.

The 2009 ERCOT State of the Market Report[35] estimated that the annual fixed costs of a natural gas peaker were in the range of $70 to $95 per kW-year or $70,000 to $95,000 per MW-year (Potomac Economics, 2010). The 2009 report notes that sufficient revenues to support the costs of a new peaker were only achieved once in the last four years (e.g. pricing providing sufficient remuneration of investment costs); unfortunately, those higher costs were attributed to transmission congestion and inefficient pricing.

ERCOT recently transitioned to a nodal or LMP market along with a day-ahead market. The addition of the day-ahead market should provide a more efficient means to determine which generators and resources will be needed to meet the needs of the system on the next day; thus, less over-commitment of resources should produce prices that are more reflective of the actual system needs.

The market monitor however points out that the nodal market rules still do not adequately handle pricing of situations when ERCOT dips into its operating reserves[36]. When system operators are working to maintain reliability (typically through non-market mechanisms such as public appeals and voluntary load curtailments) market prices for energy should rise to at least the offer cap.

In the long-term, the growth of shale gas in Texas will likely push prices of natural gas lower, thus making remuneration of new generator assets problematic. Resources continue to be built, despite the less than rosy outlook for revenues. When price-responsive loads enter the ERCOT market en masse, the revenue projections will likely

[35] Wholesale market reports for most ISO/RTOS are published in spring or summer for the previous calendar year, thus the 2009 report is the most recent publication available at the time of writing.

[36] Balancing authorities, groups such as ISO/RTOs, have the responsibility to dispatch generation to meet load; these entities must maintain a certain amount of operating reserve at all times to cover the loss of any unit. Use of these reserves to cover energy needs (versus a unit trip) puts the system in an unsafe operating point.

be pushed lower due to the reduced peak prices; however, the possibility of raising the offer cap may be a course of action at that point.

CAISO

California has had a turbulent history with respect to its electric market. Few can forget the rolling blackouts that were instituted during the 2000-2001 energy crisis. While many books and articles have been written that explain the why the crisis occurred[37], the main culprit can be simmered down to one major flaw: lack of hedging. California utilities chose to purchase the majority of their energy from the volatile and poorly managed spot market. With no proper hedging actions taken (forward contracting, for example), the load serving entities were bamboozled by malicious energy traders who inflated prices and manipulated resources statuses to raise spot prices of energy.

Structure

Much was learned during the crisis and today the California ISO (CAISO) operates a well-functioning and highly-competitive market[38]. CAISO operates a nodal market with day ahead, real-time and ancillary service markets. Like Texas, it has no formal capacity market; however, LSEs in CAISO are required to purchase capacity to cover 115% of their share of the projected peak load for each month. The capacity obligation is based on a 1-in-2 year forecast, in other words, the amount of procured capacity is designed to keep involuntary curtailments to at least every other year. The obligation can be met through self-supply, as in LSE-owned resources or through bilateral contracts.

The CPUC evaluated the possibility of a forward capacity market and a host of other resource adequacy measures in 2010. CAISO itself was a strong proponent of a

[37] See (Wolak, 2003) for a good expanded discussion of the California crisis.
[38] Opinion of CAISO's Department of Market Monitoring (CAISO, 2010).

centralized capacity market; however the CPUC decided to continue with the bilateral obligation with a few updates[39], which are discussed below.

Evaluation

California's previous experience with centralized markets colored its perspective on the decision to stick with bilateral capacity obligations. A bilateral arrangement is the least complicated, however unlike centralized markets, there is no price visibility, e.g. an LSE cannot determine whether the price it contracted with a generator is reasonable since there is no means to see what other LSEs are paying. The price opacity was pointed out in the CPUC's decision and suggested that prices be posted to an electronic bulletin board.

While strongly supporting the incumbent system, the CPUC is open to the possibility of multi-year forward procurement in the context of bilateral contracts.

Since capacity is procured on a monthly basis, capacity obligations are not based on the typical 1-in-10 year criteria, but on a 1-in-2 year forecast. If and when California moves to a multi-year forward procurement, CAISO will need to switch to the 1-in-10 year criteria. The CPUC notes that the current system has procured sufficient amounts of new resources to maintain reliability.

In the June 3, 2010 decision, Commissioner Dian M. Grueneich noted in a concurrence statement the benefits of avoiding FERC jurisdiction and the dangers of a complete overhaul of an electricity market. By sticking with a bilateral arrangement, California avoids the need for oversight from FERC, which the Commissioner attributes some blame for the 2000-2001 energy crisis.

---

[39] CPUC Rulemaking 05-12-013, Decision on Phase 2 - Track 2 Issues: Adoption of a Preferred Policy for Resource Adequacy, CPUC Decision 10-06-018 (June 3, 2010)

The CAISO market monitor estimates the fixed costs of a new peaker at $212 per KW-year[40] (CAISO, 2010). The hypothetical generator is not integrated into any sort of market power mitigation feature like in Texas, but gives an idea to what level new CAISO generators require remuneration. The market monitor estimated the annual revenues of a generator in Southern California to be $57.82 per KW-year in 2009. The delta between generator fixed costs and revenue should be made up by forward contracting for capacity as well as energy; however, the report does not provide any insight into whether the current resource adequacy mechanism provides the missing revenue. The omission is likely due to the fact that the terms of capacity contracts are not made public or reported to CAISO.

Australia

The Australia Electricity Market Operator (AEMO) has been operating a liberalized electricity market since December 1998 (AEMO, 2010).

Structure

While the Australian electricity market does not support a centralized capacity market, the AEMO does publish its annual "Electricity Statement of Opportunities." ERCOT took many cues from the Australian market and the ERCOT SOO and PASA reports are modeled on the Australian model. AEMO freely publishes these reports but caveats that any investor must evaluate the presented data independently. Though the published report is not exactly an IRP, in effect, the report projects the effects of different scenarios including carbon legislation.

[40] Capital and financing costs make up nearly 70% of the estimated costs of the new combustion turbine unit in CAISO. Land purchase, permitting and environmental controls are included in these costs.

In the event of a period where reserves fall short of reliability requirements, AEMO will intervene and contract out reserves[41]. The system operator is extremely wary of interfering with any market signal distortion this action may cause:

> *When exercising the RERT* [Reliability and Emergency Reserve Trader]*, actions should be taken which AEMO reasonably expects to have the least distortionary effect on the operation of the market, both in relation to the short term impact on the spot prices and the long term impact on investment signals. In determining the action to take, AEMO must consider:*
> *how it tenders and contracts for reserves; and*
> *in relation to scheduled reserve contracts and subject to clauses 3.9.3(c) and (d) of the Rules, setting the dispatch price and ancillary service prices for an intervention price dispatch interval at a value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred.*
>
> *The considerations above aim to reduce the distortionary impacts from AEMO intervening in the market to respond to a projected shortfall in reserves, and preserve market signals to foster a market response to those projected shortfalls. It provides an appropriate balance between allowing market responses to projected shortfalls to develop and providing a temporary mechanism to maintain the reliability of supply and where practicable, power system security.* (AEMO, 2010)

The above excerpt clearly shows that AEMO has no intention to affect the market for capacity. Long-term intervention is clearly prohibited but short-run procurement to protect reliability is within the AEMO's rules. The principled approach is important in the context of an energy-only market.

Evaluation

Unlike its American counterparts, AEMO does not have a market monitor that evaluates market performance or projected remuneration. The Australian Electricity Market

[41] CAISO will perform similar actions when it determines that the capacity acquired by the LSEs does not meet system's reliability needs or there is a major transmission constraint or system event that is not reflected in the capacity obligation of LSEs.

Commission (AEMC) does evaluate AEMO's operations for reliability purposes but does not make assessments about competition and market power. As stated earlier, Texas took many cues on its energy-only design from AEMO. Similar to the Texas peaker net margin, AEMO calculates a Cumulative Price Threshold (CPT)[42]; however, the Australian measure is measured over a period of seven days instead of a year. The shorter period and higher offer cap diverge from the Texan approach; the shorter periods and rather high threshold imply that the CPT would rarely be triggered[43]. A higher offer cap promotes investment (AEMC Reliability Panel, 2010) but the relatively high short-term cap on revenues may not be as effective in mitigating excessive wealth transfers[44]. Like in Texas, the CPT is designed to limit the amount of revenue generators earn; a limitation on revenues is important so that generators are not excessively remunerated or rewarded for withholding capacity.

REGIONS WITH CENTRALLY-ORGANIZED CAPACITY MARKETS

The Northeast regions discussed below all share several characteristics in common. First, all are operated as nodal markets that incorporate day-ahead and ancillary service markets. Second, with the exception of NYISO, all the Northeast markets include multiple states; even though NYISO covers only one state, the New York region is tightly integrated with its neighbors through several tie lines. Third, all the Northeast markets have offers capped at \$1000/MWh. Fourthly, the regions, again with the exception of NYISO, have a multi-year forward procurement of capacity. Finally, the regions consider the unforced capacity or UCAP of resources and determine the amount of

[42] AEMO has set the CPT to 15 times VOLL or \$AUD 187,500 over the course of one week. Compare this to the Texas threshold of \$175,000 over the course of a year.

[43] The CPT was triggered for the first time on March 17, 2008 in South Australia after 15 days of extremely hot weather.

[44] A euphemism for periods when loads are exposed to high prices for energy.

UCAP needed to meet reliability. UCAP is the physical capability of a resource reduced by the forced outage rate of the resource[45].

The basic tenets of capacity markets were discussed earlier in the report. The sections below go into detail about each region's specific approach to resource adequacy.

NYISO

Like California, NYISO covers only one state but has extensive ties to its neighbors. NYISO currently requires an annual procurement of capacity.

Structure

LSEs in NYISO can either self-supply, contract or purchase capacity through one of the three NYISO-administered auctions. The first auction, called a "strip auction", provides 6-month blocks of capacity for a given capability period[46]. The second monthly auction covers the remainder of a given capability period e.g. the August monthly auction can cover the obligations for August as well as the rest of the summer season (up to October). The third auction is a monthly spot market auction that covers the needs for a given month e.g. the August spot market covers the obligations for the month of August; all capacity purchase obligations must be met by the third auction.

Demand curves are defined for three zones in the NYISO: New York City, Long Island and NYCA (NYISO Control Area), or areas outside of New York City and Long Island. The Installed Reserve Margin (IRM) for May 2009 to April 2010 was 16.5%. Capacity beyond 15% and 18% for NYCA and New York City/Long Island is valued at $0 (Potomac Economics, 2010). As discussed earlier, the IRM and zero-crossing points define the slope of the demand curve.

---

[45] For instance, a 100 MW generator with a 1% forced outage rate would have a UCAP value of 99 MW.

[46] Capability periods are defined as 6-month blocks of time, based on the winter (November to March) and summer (May to October) seasons.

Capacity resources can be conventional generation, intermittent resources, distributed generation as well as demand-side and external resources outside of the NYISO footprint.

Evaluation

New York's electricity market was restructured in 1998 (FERC, 2008). Consolidated Edison (ConEd) previously held all the generating assets in New York City. Since 1998, different investors have purchased ConEd's assets and ConEd became an LSE.

In 1999, NYISO became operational and setup annual capacity auctions. (Chao & Lawrence, 2009) note that the NYISO annual capacity market exceeds $1.5 billion with the annual action clearing 50% of the total UCAP procured.

Table 3 below compares the estimated costs for a new combustion turbine and the estimated revenue of a combustion turbine in three different zones of NYISO. 2009 did not present extremely high loads, thus the estimated revenues fell short of CONE.

Area of NYISO	**Estimated Costs of New CT [$/KW-year]**	**Estimated Revenues for a new Combined Cycle** [$/KW-year]	**Estimated Revenues for a new Combustion Turbine** [$/KW-year]
New York City	203	160	80
Long Island	180	165	75
Upstate New York	109	115	40

Table 3: Comparison of Estimated Costs and Revenues for a New Combustion Turbine in NYISO in 2009 (Potomac Economics, 2010)[47]

[47] Values for estimated costs are based on Figure 9 and 10 from (Potomac Economics, 2010).

ISO-NE

As a result of a series of FERC proceedings and administrative law hearings, ISO-NE began a forward capacity market (FCM) in 2006[48] and has successfully administered four capacity auctions.

Structure

The ISO-NE FCM auction is based on a "descending clock" auction. Suppliers offer in their capacity based on the price they are willing to accept. The ISO announces a starting price and reduces the prices until the amount of capacity offers equals the amount of capacity to meet the needs of the ISO. In the last three auctions conducted by the ISO, the prices hit the floor price for capacity, or the minimum price for capacity in the ISO-NE market[49]. Like in other capacity market auctions, the demand curve is determined by the target IRM and the administratively determined CONE. In the case of ISO-NE, the intersection of the supply and demand curves has not determined the market clearing price for capacity, but rather has been set by the minimum floor prices.

Evaluation

New resource capacity entered the capacity market even though the market clearing price was far below CONE. The odd behavior was due in part to the State of Connecticut's RFP for new capacity. The Connecticut RFP was a result of Connecticut HB 7432, which directed the Connecticut PUC to develop peaking generation resources. The RFP essentially promoted the use of cost-of-service generation, but as these generators could bid into the capacity market, the new resources could receive an additional—and unnecessary—revenue stream. Based on the external market monitor report for 2009, no party or stakeholder found this to be problematic, however. The Connecticut bill did incent higher amount of energy efficiency, but how the addition of peaker generation

[48] *ISO New England, Inc.*, 119 FERC ¶ 61,045 (2007).

[49] As stated earlier, ISO-NE will lower the market price until the amount of capacity willing to sell at the given price equals the IRM. When the price hits the minimum or floor price, an amount of capacity above the IRM may be procured.

through cost-of-service agreements could provide Connecticut consumers with energy savings is not clear.

The 2009 market monitor report indicated that 1223 MW of new resources (out of a total of 2007 MW of new resources) were due to the 2009 RFP and previous agreements. The remaining 773 MW of new capacity were mainly renewable resources or uprates to existing generators, which have lower costs compared to a new combustion turbine e.g. resources that are likely far below CONE levels.

Unfortunately, neither the ISO-NE internal market monitor nor the independent market monitor tracks the estimated revenues and costs of new resources. Despite the lack of data, it is unlikely that an investor can recover the costs of a new combustion turbine since the market clearing price in the capacity auction was so far below CONE.

PJM

Like ISO-NE, PJM too operates a forward capacity market, which it calls the Reliability Pricing Model or RPM.

Structure

Based on a three-year forward procurement of capacity, the basic function of RPM is similar to FCM. A demand curve or Variable Resource Requirement curve (VRR) is based on the target level of capacity for each load deliverability zone in PJM; per the usual convention, the curve slopes downward with the target capacity level intersecting at CONE. The upper level of the curve is not based solely on 1.5 times CONE; PJM determines the "cap" at a level based on CONE less revenue earned in the energy and ancillary services market times 1.5.

The VRR is used in the first auction that PJM administers (called the Base Residual Auction), subsequent auctions (called incremental auction) are based on demand curves based on the buy bids submitted by market participants. The three incremental auctions, which take place a year, 10 months and three months before the procurement period, respectively, allow changes in the offers from suppliers to reflect changes in actual resources (PJM Interconnection, LLC, 2010).

A variety of resources can participate in the capacity market including:

- Generation
- Load management products
- Energy efficiency resources
- Qualified transmission upgrades
- Bilateral transactions outside of the RPM auction

To address a declining amount of quick-start and load-following resources, PJM requires that resources procured under RPM have quick-start and load-following capability. PJM argued that such treatment is necessary since energy and ancillary service markets do not provide such valuation[50] .

Evaluation

The PJM market monitor estimated that 20-year levelized costs for a new combustion turbine were $128.71 per installed kW-year in 2009 (Monitoring Analytics, LLC, 2011). The market monitor also estimated the net revenues for a CT in each of the 17 load deliverability zones in PJM, see Table 4. Like in the other ISO/RTOs, in no zone did the net revenues exceed the costs for a new CT. While there is significant difference across the various load zones in PJM, net revenues were too low to support new entry.

[50] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006)

PJM Zone	2009
AECO	$70.29
AEP	$42.85
AP	$67.39
BGE	$99.89
ComEd	$43.51
DAY	$44.10
DLCO	$45.83
Dominion	$55.44
DPL	$79.21
JCPL	$77.42
Met-Ed	$70.28
PECO	$75.31
PENELEC	$66.25
Pepco	$108.26
PPL	$69.19
PSEG	$74.95
RECO	$73.64
PJM (Average)	$55.94

Table 4: 2009 PJM Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed kW-year) (Monitoring Analytics, LLC, 2011)

The integration of a quick-start and load-following requirement in the PJM capacity market is an interesting means to acquire resources that meet a desired profile. As more coal-fired capacity is retired, generating resources that traditionally provided load-following capability are disappearing. Requirements on new resources ensure that PJM will maintain a proper mix of resources to ensure reliability.

Perhaps the most interesting comment made during RPM's deliberations at FERC was PJM's note that:

> *[C]apacity markets should diminish in importance to the extent energy markets in the future prove capable, standing alone, of offering adequate assurance of reliability. Accordingly, the RPM proposal . . . includes provisions that will*

> *automatically de-emphasize the capacity market as the energy market proves more effective at incenting capacity resources*[51].

PJM points out that the upper cap of the VRR curve in effect limits the amount of revenue earned from the capacity market and as revenue from the energy and ancillary service market exceed capacity revenue, the effect of RPM will diminish. RPM is however not a temporary measure and no transition measures towards an energy-market are being put in place. Most importantly, there is no current means to raise the $1000/MWh offer cap in PJM.

---

[51] *Id.*

Chapter 6: Future of Resource Adequacy

DIFFERENT STROKES FOR DIFFERENT FOLKS

Evolutions to any RA solution must be tailored to fit the risk-profile and incumbent regulatory framework. Prescribing solutions without full understanding of the local issues and political economic relationships makes little sense. For instance, a legislative mandate to shift from one construct to another could put reliability at risk. A regulatory staff that is unprepared for the potential of market manipulation could expose the public to high prices and/or rolling blackouts. Consider also the vast changes that must occur for market rules and software updates. Hence, if a switch from one RA construct to another is desired, then a gradual set of incremental changes are best.

The incumbent system however does not leave out the possibility for improvement. The section below looks at changes that could be made that improve the efficiency of procuring capacity and improving the reliability with regards to higher penetrations of renewable resources.

PRICE RESPONSIVE LOADS

Regardless of the type or even lack of RA measures, price-responsive demands must be encouraged. There cannot be a more cost-effective way to achieve capacity requirements other than having load respond to price signals. The key is to switch loads from peak to off-peak periods.

Delaying or waiting to use loads during other parts of the day (by manual or automatic means) is one way to utilize off-peak power. The operation of many of the appliances in the residential load class can be shifted in time including washing machines, dryers and dishwashers. Significant loads such as air conditioners are not capable of time shifting, since the cool air produced at night would be lost later in the day. Ice storage air conditioning systems are a growing alternative to traditional air conditioning systems, however a large rooftop-mounted unit is required and not practical for residential installations.

The next wave of technology that can capture the benefits of off-peak power is the ability of appliances to communicate directly with the utility, the electric meter and other appliances. This level of integration requires the most sophistication because it not only requires significant infrastructure such as wireless communications and completely new appliances and loads but also standard protocols for relaying information.

The primary piece of information that the “smart appliances” would need is the price signal. Price signals from the day-ahead electric market would be sent to the smart appliances and would determine the mode of operation for the next 24 hours. For example, if high prices were expected tomorrow, the air conditioner would determine when the best time to cool the house would be, leveraging the lower prices leading up to the peak and scaling back electric demand (in this case, raising the thermostat). Similarly, refrigerators could make a similar determination and lower the temperature ahead of the peak (but not too low that foods become frozen!) and skip cycling the refrigerant compressor during the peak periods.

The smart meter would be at the heart of the appliances and utility grid ecosystem. Through the smart meter, all pricing information from the grid would be relayed. The smart meter could also send back to the utility the relative price sensitivity the user has programmed into the various household appliances; the utility could gauge the expected response of loads out on the grid. Such sophistication will take significant work since there is currently a lack of two way communications between the user and grid (smart metering is currently a one-way street with data being sent directly to the utility) and residential appliances currently lack the programming sophistication to communicate and describe the expected load pattern. Utilities can easily pull data from meters, but they lack the ability to crunch pricing, demand and time of day data into the current load forecasting infrastructure[52].

The road to dynamic pricing will not be a simple task. Dynamic pricing or its other variants such as critical peak pricing require shifts in the perception on the regulator's side as well as overcoming significant technology hurdles.

CHANGES IN THE RESOURCE MIX

As more and more states adopt renewable portfolio standards (RPS) and a national RPS mandate gains traction, system operators will need additional tools to manage the intermittency of variable resources. Traditional generation planning uses hourly load and resource profiles. However, higher-penetration scenarios push the time-frame of interest to *inter-hour* periods. System operators procure the amount of ancillary services they expect to cover variability in intermittent resources. Such measures are acceptable when seen in the context of low-renewable penetrations. If aggressive targets for renewables are agreed to and met, then the short-term planning for resources will be inadequate for meeting the goals of reliability.

The ERCOT and Australian PASA provide the shorter-term outlooks for ancillary services. For markets that have capacity markets, an equivalent to the IRM that indicates the target level of responsive reserve needed to maintain reliability is needed. While the majority of new capacity is gas-fired, the ability of the generator to provide responsive reserve is not guaranteed. Those areas that have capacity markets could also incent low-carbon or energy storage resources through adders on the auction clearing price. PJM's RPM requirement for quick-start and load-following resources is also one approach currently in practice today.

---

[52] Utilities currently have no need for such tools because demand is price insensitive. Once smart meters and dynamic pricing are widely available, utility-side software tools could be developed that can provide insight into how load would react to a set of weather and price conditions at a given point in the day. One should not neglect the privacy concerns associated with sharing usage and pricing data with utilities.

Chapter 7: Conclusions

The benefits of each of the resource adequacy constructs discussed above each have certain benefits and drawbacks.

Energy markets must set a relatively high offer cap, which also caps revenues earned by resources. High energy prices can be scary and the political backlash can mean regulators and policymakers avoid effective policies. The SOOs and PASAs in ERCOT and Australia are the indicators of future needs in the short and long-term but like an IRM developed in capacity markets, are dependent on system operator projections. Despite the lack of an additional revenue stream or RFPs from state governments, investors in energy-only markets are building new resources. The price signals alone delivered by the markets are incenting new entry.

Capacity markets may incent more resources than necessary and negatively affect projected revenue streams; situations like in Connecticut where additional capacity was brought on-line outside of market measures, are unlikely to reap significant savings to all consumers.

The markets of Australia and PJM have many forward thinking approaches. Perhaps PJM's comment that capacity markets are bridges to fully-functioning energy-only markets is true. However, the broad range of resources incented in capacity markets provide additional options for LSEs to acquire capacity and can even specify the characteristics of future resources. While energy-only markets may be the eventual outcome of all electricity markets (see PJM's comment on RPM), current implementations should be modified to learn from the best-practices from capacity markets.

While each of the regions studied appears to have successfully met the needs for capacity expansion, the resource adequacy constructs themselves may not be responsible for such experience. The studied regions may have an oversupply of capacity and thus no matter the construct, projections for resources to meet load have been adequate. An oversupply of capacity may also explain the lackluster results in terms of remuneration as well. However, to argue that a region has an oversupply of capacity is dangerous since reliability is jeopardized when capacity shrinks. No region (nor would any regulator) allow their portion of the grid to remain stagnant in terms of resource development.

Sufficient remuneration of investments will be a problem no matter what the resource adequacy construct. There is no clear winner between the current crop of energy-only, capacity markets and bilateral contract mechanisms. Markets must be liquid (competitive), allow demand to participate (the cheapest resource that can respond) and provide some indication to investors and the public about the future need (amount) and type of resources. Such communication can be a capacity obligation placed on LSEs or a forward-looking statement like the Australian SOO. Future iterations of resource adequacy constructs will likely blur the line between energy-only and capacity markets. Such a hybrid construct would require a large and active amount of price responsive demand as well as a high offer cap. In addition, future constructs will need to solicit appropriate resources to accommodate high penetration scenarios of wind and other intermittent resources; different sets of analyses will need look at the inter-hour fluctuations produced by intermittent resources. Finally, pilot dynamic pricing programs like the PowerCentsDC program have proved successful, thus the hurdles to achieve adoption of achieving an active price responsive demand are diminishing.

Appendix

Summary of the PowerCentsDC program

During the summer of 2008 and winter period of 2008-2009 a pilot program was put in place in the District of Colombia that provided selected electric customers with dynamic pricing (eMeter Strategic Consulting, 2010).

PEPCO[53] customers were divided into three different pricing groups, Critical Peak Pricing (CPP), Critical Peak Rebate (CPR) and Hourly Pricing (HP). CPP customers were given a slight discount for most hours of the year, but were exposed to very high prices during peak periods (limited to 60 "critical peak hours" and 15 "critical peak days"); customers were notified of peak events via phone, email or text message. CPR customers established a baseline consumption and were asked to reduce consumption during peak periods; reductions in usage below the baseline were returned as rebates. PowerCentsDC staff were aware of problems with establishing baseline usage[54] and did not notify customers of when baseline measurements were taken. HP customers were exposed to hourly prices from the PJM day-ahead market and could see the prices on the PowerCentsDC website or in real-time on smart thermostats provided to HP customers.

Price Plan	Peak Reduction - Summer	Peak Reduction - Winter
CPP	34%	13%
CPR	13%	5%
HP	4%	2%

Table 5: Summary of Load Reductions through the PowerCentsDC Program

[53] The electric utility in the District of Colombia.

[54] Inflated baselines induce lower reductions and less overall system benefit.

Program designers selected critical peak periods based on the temperature triggers. Based on historical data from the previous 5 years, a temperature threshold of 90° in summer and 18° in winter was selected. The thresholds were selected based on the number of days the temperature was exceeded in summer (or below for winter) since critical peak events were limited throughout the year. Critical peak days were limited to four hours in a given day.

Program participants consisted of residents throughout the District, with particular emphasis on income-limited households. Experience from the program showed that limited income participants signed up in higher numbers relative to other participants but did not achieve as high reductions; limited income participants were only CPR participants, however.

Table 6 below summarizes the monetary savings achieved by each of the three PowerCentsDC groups. The HP customers greatly benefited from falling wholesale prices on the PJM market during the program period; certainly, the amount of reduction (see Table 5) is not consistent with the savings achieved; it is likely that the reduced prices on the PJM market did not incentivize the participants to aggressively reduce loads. However, overall all customers achieved some level of savings and load reduction.

Price Plan	**Average Bill SOS**[55]	**Average Bill PowerCentsDC**	**Dollar Savings**	**Percent Savings**
CPP	$101.26	$99.70	$1.56	2%
CPR	$99.66	$95.07	$4.59	5%
HP	$110.44	$77.42	$43.02	39%

Table 6: Summary of Savings Achieved by PowerCentsDC Customers

[55] Standard Offer of Service, the normal rate customers pay.

Bibliography

Adib, P., Schubert, E., & Oren, S. (2008). Resource Adequacy: Alternate Perspectives and Divergent Paths. In F. P. Sioshansi, *Competitive Electricity Markets* (pp. 327-362). Elsevier Global Energy Policy and Economics Series .

AEMC Reliability Panel. (2010). *Final Report, Reliability Standard and Reliability Settings Review.* Australian Electricity Market Commission.

AEMO. (2010). *Introduction to Australia's National Electricity Market.* Australian Electricity Market Operator.

AEMO. (2010). *Procedure for the Excercise of Reliability and Emergency Reserve Trader.* Australian Electricity Market Operator.

Bidwell, M. (2005). Reliability Options A Market-Oriented Approach to Long-Term Adequacy. *The Electricity Journal*, 11-25.

Bushnell, J. (2005). Electricity Resource Adequacy: Matching Policies and Goals. *The Electricity Journal*, 11-21.

CAISO. (2010). *2009 Annual Report on Market Issues and Performance.* California Independent System Operator.

Chao, H., & Lawrence, D. J. (2009). How Capacity Markets Address Resource Adequacy. *Power & Energy Society General Meeting, 2009. PES '09. IEEE* (pp. 1-4). IEEE.

Cramton, P., & Stoft, S. (2006). The Convergence of Market Designs for Adequate Generating Capacity. *Report for the California Electricity Oversight Board*.

Cramton, P., & Stoft, S. (2008). Forward reliability markets: Less risk, less market power, more efficiency. *Utilities Policy, 16*, 194-201.

Credit Suisse. (2010). *Growth From Subtraction.* Available at http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19.

Dallas Business Journal. (2003, March 7). *Texas Commercial Energy files for bankruptcy.* Retrieved April 19, 2011, from Dallas Business Journal: http://www.bizjournals.com/dallas/stories/2003/03/03/daily50.html

eMeter Strategic Consulting. (2010). *PowerCentsDC Program Final Report.* Smart Meter Pilot Program, Inc.

FERC. (2008). *Enforcement Staff Report, Findings of a Non-Public Investigation of Potential Market Manipulation by Suppliers in the New York City Capacity Market.* Federal Energy Regulatory Commission.

Fleisher, J. M. (2008). ERCOT's Jurisdictional Status: A Legal History and Contemporary Appraisal. *Texas Journal of Oil, Gas and Energy*, 4-20.

Fraser, H. (2003). A Critique of the Resource Adequacy Requirement Proposed in FERC's SMD NOPR. *The Electricity Journal*, 23-28.

Joskow, P. (2007). Capacity Payments in Imperfect Electricity Markets: Need and Design. *Utilities Policy*, 159-170.

Kirschen, D. (2004). *Fundamentals of Power System Economics.* John Wiley and Sons, Ltd.

Lesh, P. (2009). Planning for the Future. *The Electricity Journal*, 45-53.

Monitoring Analytics, LLC. (2011). *2010 State of the Market Report for PJM.* Monitoring Analytics, LLC.

Oren, S. S. (2005). Generation Adequacy via Call Options Obligations: Safe Passage to the Promised Land. *The Electricity Journal*, 28-42.

PJM Interconnection, LLC. (2010, June 1). Manual 18: PJM Capacity Market.

Potomac Economics. (2010). *2009 State of the Market Report for the ERCOT Wholesale Electricity Markets.* Public Utility Commission of Texas.

Potomac Economics. (2010). *2009 State of the Market Report, New York ISO.* New York ISO.

Reeder, M. (2006). Want to Put an End to Capacity Markets? Think Real-Time Pricing. *The Electricity Journal*, 38-48.

Regulatory Assistance Project. (2010). *Clean First: Aligning Power Sector Regulation with Environmental and Climate Goals.*

Rochlin, C. (2004). Resource Adequacy Requirement, Reserve Margin, and the Public Goods Argument. *The Electricity Journal*, 52-59.

Shanker, R. J. (2003). Comments on Standard Market Design, Resource Adequacy Requirement, FERC Docket No. RM01-12-000.

Siddiqi, S. N. (2007). Resource Adequacy in the “Energy-Only” ERCOT Market. *Power Engineering Society General Meeting, 2007. IEEE*, (pp. 1-3).

Wen, F., Wu, F. F., & Ni, Y. (2004). Generation capacity adequacy in the competitive electricity market environment. *Electrical Power and Energy Systems*, 365–372.

Wolak, F. A. (2003). Diagnosing the California Electricity Crisis. *The Electricity Journal*, 11-37.

Zhao, F., & Litvinov, E. (2010). Defining and Pricing Capacity Product in Capacity Markets. *Power and Energy Society General Meeting, 2010 IEEE*, (pp. 1-6).