

Capacity Markets in the U.S. Electric Industry, the Effects of Deregulation and the Push to Renewables

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Abstract

In response to the effects of deregulation and the emergence of renewable energy sources, capacity markets have emerged as a construct to ensure system reliability and adequate generation capacity. The capacity market is a market-wide and price-based approach to capacity remuneration mechanisms, in which a central regulator sets the price at which to procure generation capacity through a capacity auction. Price caps in the energy-only market prevent the sufficiency of scarcity pricing during blackouts to generate sufficient revenues to provide for investment of plant assets. In analyzing worldwide fuel diversity, we see that coal is the predominant energy source used worldwide in 2022. The U.S. has already begun the process to move away from coal, and sees natural gas as the primary energy source of its energy zones. Wind power has made more progress than solar power in the United States, and worldwide. Maybe China is correct that utilizing coal as a cheaper fossil fuel energy source than natural gas is a smarter idea than transitioning so quickly to clean energy and cleaner burning gas.

Keywords: capacity markets, electricity markets, deregulation, renewable energy sources

I. Introduction

Electricity market deregulation has captivated the world. However, questions arise, such as are investments in new generating capacity sufficiently incentivized in the restructured electricity markets, or are capacity remuneration mechanisms such as capacity markets necessary to ensure resource adequacy and capacity reserves? Defined, resource adequacy and capacity reserves refer to adequate investment of plant generation, fixed assets, and sunk costs. Since deregulation, or liberalization, the US electric grid has seen the emergence of Independent System Operators (ISO) and Regional Transmission Operators (RTO). Some of the US has maintained a traditional regulated electric industry with generation, transmission, and distribution of electricity being controlled by one electric utility, while some areas have transitioned to ISOs and RTOs where a central authority regulates prices. Further, some of the ISOs have created capacity markets to ensure resource adequacy, while some have continued to rely just on the energy-only market. Thus, it can be stated that the capacity market construct is a creation of deregulation.

The push to renewables in the electric industry has created changes in the markets, including for prices of electricity. Renewables such as wind and solar have zero marginal cost, or fuel cost, so they bring down spot prices in the energy-only market. Electric utilities must therefore find a way to effectively price renewables into the spot market. The futures market in electricity is typically used for risk hedging. Voluntary Renewable Energy Certificates (REC) prices in the

U.S. increased from \$0.31/MWh in August 2017 to \$0.70/MWh in August 2018.¹ Renewable energy purchases can either be voluntary or mandatory. Some states have mandatory requirements for percentage of energy used, and also impose penalties if the quotas are not met. In the energy only market, the merit order effect describes the lowering of prices on the electricity market due to an increased supply of renewable energies, with renewables contributing to the missing money problem of investment in fixed assets for power plants.

Liberalized electricity markets have been questioned due to reliability concerns resulting from increasing energy demands, the decommissioning of conventional power plants, and the steady growth of renewable energy sources (RES) (Gailani et al., 2020). It is thus a relevant question to ask whether in light of the increased use of RES, capacity markets can help to distribute revenue and avoid the missing money problem. Hach and Spinler, 2018 note two RES characteristics which pose problems to traditional electricity market design: 1) low marginal costs and 2) intermittency. One, low marginal costs, are the result of a marginal cost bidding structure in an energy-only market, where the merit order is pushed from the left by renewables and consequently high marginal cost thermals, such as peak-load gas-fired plants, are priced out of the market. Two, due to the intermittent nature of RES, and since there are neither grid-scale battery storage technologies nor large-scale demand response programs available, thermal generation capacity is still needed at the same level to ensure generation adequacy, with or without the RES feed-in.

The emergence of renewable energy sources has coincided with the development of capacity markets. Many of the new generators providing capacity market services use lithium-ion batteries (LIBs) to store the energy due to their high energy density and long life cycle (Lee et al., 2019). In fact, batteries can enhance new generators by providing capacity services ranging from 40% to 100% of their nameplate capacity, thus reducing the number of shortage events in the capacity market (Sioshansi et al., 2014). Stafell and Rustomji (2016) find that the revenue from energy storage devices can be tripled if LIBs are utilized to provide energy reserve services in the electricity markets. Teng and Strbac (2016) find that batteries participating in the capacity market can secure substantial upfront revenue, while only marginally reducing profits from other markets. However, lithium-ion batteries typically only have storage lives of 4 hours, and so new battery technologies are needed such as sodium and tin based batteries to increased grid-storage capacity.

In Europe, they have transmission system operators (TSO) and distribution system operators (DSO). In the United States, they have independent system operators (ISO) and regional transmission operators (RTO). The ISO and RTO are effectively the same thing in the United States. The TSO and DSO are different functions in Europe. Khajeh et al. (2019) provides a description of the differences between the TSO and DSO in Europe. TSOs utilize system-wide flexibility services to maintain system frequency, by following load and/or generation variations close to real-time. DSOs, conversely, utilize local flexibility services to maintain system

¹ US EPA, U.S. Renewable Electricity Market, Retrieved July 19, 2023.
<https://www.epa.gov/green-power-markets/us-renewable-electricity-market>

frequency, and can purchase flexible energy resources connected to these networks to regulate voltage and manage congestion.

Failures of Current Electricity Market Design (Komorowska, 2021)

- 1) Electricity supply and demand; can't store electricity without batteries
- 2) Low short-run price elasticity of demand; consumers can't respond to hourly fluctuations in price in real-time
- 3) Lower operating costs for renewable energy generators, resulting in lack of capacity payments to conventional generators for new investment
- 4) Price caps during periods of peak demand, which restricts market signals during these periods which could result in better capacity payments without price caps

In the United States, liberalized competitive markets serve 70% of electricity customers, with the Federal Energy Regulatory Commission (FERC) approving and regulating capacity markets via independent system operators and regional transmission operators. California, Texas, and New York are restructured competitive markets. The ISO includes the RTO. About half of the United States is still traditional regulated markets, where the electric utility controls the generation, transmission, and distribution of electricity. In the United States, there are three interconnections for the electric grid. The Eastern Interconnection comprises the area from the Great Plains states eastward to the Atlantic coast. The Western Interconnection comprises the area west of the Great Plains to the Pacific coast. The Electric Reliability Council of Texas (ERCOT) covers most of the state of Texas. Seven RTOs operate across the United States: the California Independent System Operator (CAISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO, PJM Interconnection, New York ISO (NYISO), and ISO New England (ISO-NE). These RTOs cover part or all of 38 states and the District of Columbia.

The Federal Energy Regulatory Commission (FERC) is responsible for overseeing regional transmission organizations' (RTOs) development and operation of capacity markets. The RTO has the authority and means to create a capacity market, which is a set of financial contracts from different regions and operators. Thus, a capacity market is wholly an RTO creation, as a regulated utility has neither the means nor the need to create a capacity market. The regulated utility lacks the means because it is not a grid operator for several different regions and zones, and lacks the need because its regulated rates already provide a return to ensure resource adequacy and capacity reserves.

Capacity markets are a reserve market, an economical construct, used in the electricity industry to ensure resource adequacy and capacity reserves. With increasing electricity demand and increased use of renewable energy sources, it is important to ensure adequate reserves of generation capacity. However, challenges arise with the electricity reserve market construct in terms of capacity markets' and capacity auctions' complexity and high cost relative to benefit (Rusco, 2017). The four RTOs with capacity markets which FERC has approved to maintain resource adequacy and capacity reserves are: ISO New England, Midcontinent ISO, New York ISO, and PJM. The three RTOs without capacity markets are: California ISO, Southwest Power

Pool, and Texas ERCOT. The two regions that are still regulated markets for electricity are the West and the Southeast. CAISO utilizes a resource adequacy requirement on load serving entities, but has not created a centrally coordinated capacity market. Bhagwat et al. (2016) suggests that characteristics of these U.S. capacity markets include the creation of separate markets for flexible capacity, geographical definition of market sub-regions, and modifications to market clearing mechanisms, such as use of demand curves.

Bhagwat et al. (2016) notes issues plaguing capacity market design in the United States, including: 1) the role of demand response 2) whether locational constraints should be imposed 3) how far forward capacity reserve markets should be run, and 4) whether separate markets should be created for flexible capacity to back up intermittent renewables. Another issue that arises with capacity markets, as seen in the European Union, is seams issues (US) or cross-border effects (EU). In terms of cross-border effects, inefficiencies might arise when wholesale electricity markets with different capacity markets are interconnected, or when regions with capacity markets are interconnected with energy-only markets. These cross-border spillover benefits or costs could lead to sub-optimal performance of the capacity markets.

RTOs Facilitate Integration of New Technologies and Market Participants

-Yoo and Blumsack (2018)

- 1) Renewable power generation
- 2) Energy storage
- 3) Demand response

II. Capacity Remuneration Mechanisms (CRMs)

A capacity remuneration mechanism is implemented to ensure that there is adequate generation capacity to meet the reliability standard, and to increase the level of security of supply in the electric grid. A CRM scheme works by providing financial compensation to the operators of capacity resources in return for keeping their generation units available. Certified capacity is the capacity to be available during crucial hours, and is determined by calculating the de-rating factors, which differ within different capacity mechanisms (Pugl-Pichler et al., 2020). CRMs provide an incentive for new entrants to locate in regions where there is a need for additional resources (Miller et al., 2012). CRMs help to maintain existing capacity or invest in new installations, and address generation capacity and flexibility adequacy concerns (Leiren et al., 2019).

Image 1. Capacity Remuneration Mechanisms

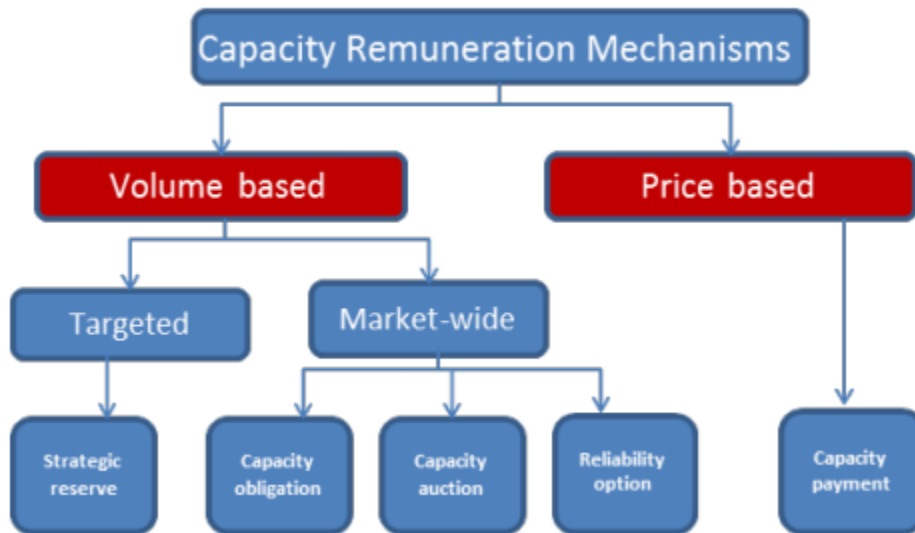


Image 1: Taxonomy of CRMs, Published in 2017, THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS reports on: CAPACITY REMUNERATION MECHANISMS AND THE INTERNAL MARKET FOR ELECTRICITY.

There are two categories of CRMs: (1) price-based capacity mechanisms: capacity payments and (2) volume-based capacity mechanisms: strategic reserve, reliability options, capacity obligations, and capacity auctions. Targeted capacity remuneration mechanisms address only a part of the market, whereas market-wide approaches target the entire market. Price-based capacity mechanisms utilize capacity payments set by the regulator, and set the price first before determining volume. Value of Lost Load (VoLL) is the willingness of consumers to pay to avoid a supply disruption, and the set capacity remuneration of a price-based mechanism should not exceed the (VoLL) reduced by the revenues from the energy market (Cramton et al., 2013). Volume-based capacity mechanisms involve the regulator stipulating the required capacity, or volume first, then setting the price of this capacity through auctions or contracts. In volume-based structures, the capacity price paid to all generators is the last bid accepted to cover the required capacity.

CRMs

(1) tender for new capacity; (2) strategic reserve; (3) reliability options; (4) targeted capacity payment; (5) market-wide capacity payment; (6) central buyer capacity market; (7) decentral demand driven capacity market.

A tender for new capacity is a targeted and volume-based mechanism. In a tender, the required additional capacity is ensured through financial support granted to capacity providers. Financing the construction of new capacity or long-term power purchase agreements could be the form of the tender.

Strategic reserves are targeted and quantity-based mechanisms. In a strategic reserve system, a capacity reserve, which is formed outside the energy markets, is only activated if the supply on the wholesale market is not able to meet the demand, or if no market clearing takes place (Pugl-Pichler et al., 2020). Strategic reserves is a construct consisting of generators with high operating costs and/or demand-side resources that are contracted by the TSO or RTO and are dispatched when the market does not provide sufficient generation capacity (Bhagwat et al., 2016). In a strategic reserve system, control of some power stations is transferred to the TSO or RTO, and the strategic reserve is dispatched at a price above the variable costs of the generation units when more generation capacity is needed. Dispatching the strategic reserves causes the price of electricity to increase, thus stimulating investment in generation resources. Strategic reserves may be dispatched in case of shortage of supply in the spot market or a price settlement above a certain electricity price (Söder et al., 2020).

When discussing the value of strategic reserves versus capacity markets, Lambin and Léautier (2019) find that the direct, upfront cost of capacity support is greater when the security of supply (SoS) standards are met with capacity markets instead of a strategic reserve, although the energy prices are a little higher with a strategic reserve. A central body performs the procurement and compensation of capacities in both a strategic reserve scheme and a central capacity market. A difference between these two is that strategic reserves only come into play in emergency situations, and are not entitled to participate in the energy-only market or the balancing energy market (Monjoie, 2021).

Reliability options are a market-wide and volume-based mechanism. A reliability option is a CRM where the market prices capacity from the bids of competitive new entry in an auction, and physical capacity is bundled with a financial option to supply energy at spot prices above a strike price. Cramton et al. (2013) identifies two major advantages of reliability options, in that the capacity payment: 1) hedges load from high spot prices and 2) reduces supplier risk by replacing peak energy rents (the rents derived from selling energy at high spot prices during periods of scarcity) with a constant capacity payment.

Administrative capacity payments are where a central authority determines the price of the capacity, and can be either targeted or market-wide payments. Targeted payments are where specific plants receive capacity payments, a targeted and price-based mechanism, such as operators of a certain generation technology, such as flexible peak load power plants (Pugl-Pichler et al., 2020). Market-based capacity payments constitute a market-wide and price-based scheme, whereby all generators and demand response providers receive a predetermined price, which is set by a central regulator.

The centralized capacity market, or single buyer model, is a market-wide and volume-based approach, where all market participants, except those already receiving state aid, are allowed to participate and guarantee capacity in the capacity market. The operator (TSO or RTO) of the capacity market determines the required volume in advance, and the clearing price in the capacity auction is determined by the market. Decentralized capacity obligations also represent

a market-wide and volume-based approach, however, there is no centralized bidding process to determine the compensation for generators, with suppliers instead being obliged to contract sufficient capacity to meet consumption demand (Pugl-Pichler et al., 2020).

A capacity market is a type of capacity remuneration mechanism. Capacity markets can be either centralized, regulated by the government, or decentralized, demand-driven. A centralized design determines how the cost is allocated to final consumers, whereas a decentralized design determines how retailers value a marginal capacity. Centrally regulated capacity markets can be either: 1) comprehensive, or market-wide, where all plant operators can participate, or 2) targeted, where only specific institutions can participate. Decentralized demand-driven capacity markets utilize balance group managers, who determine the pricing of capacity, the capacity of which is determined by the demand side. Monjoie (2021) suggests that the demand-driven model must be both the creation of products such as the “provision of reliable capacity” and “backup capacity,” and also of sufficient demand for capacity products. Retailers must buy the capacities directly in the capacity market to cover their contracts in a decentralized demand model, with the penalty system used to enforce the obligation.

Capacity markets maintain adequate capacity reserves to improve the resource adequacy of the system, with the capacity reserves calculated from the loss of load expectation (LOLE) requirement of the ISO. The expected number of hours during which resources are insufficient to meet the demand needs in a given zone during a given time period is LOLE. Cramton and Stoft (2005) suggest that capacity markets are needed because only the supply side and not the demand side actively participate in the electricity market, so there will always be imperfections such as exercise of market power or regulatory interventions in an energy-only market. Further, a second argument for capacity markets is that an increasing share of renewables aggravates the resource adequacy problem due to fluctuations in prices and demand for thermal conventional generation, and RES thus provide price-inelastic supply due to the low marginal costs. Cramton et al (2013) notes that due to decreasing load factors, the attractiveness of conventional generation investments decreases with rising RES use.

In a capacity market, the market establishes the price through an auction after the government regulator determines the required capacity. Capacity markets have gained increased prominence over strategic reserves and capacity payments. All capacity markets include capacity payments as remuneration, though not all capacity payment mechanisms are capacity markets. The capacity payment construct can be defined as separate from the capacity market construct. One major difference in capacity markets is the timing of when they procure capacity. Some obtain commitments from plant owners 3 years before electricity is needed (ISO New England and PJM Interconnection), while some obtain commitments closer to when electricity is needed (NYISO and Midcontinent ISO). Level of resource adequacy refers to the availability of adequate power plants and other resources to meet customers' electricity needs. Reasons for the need of a capacity market for electricity include: fixed costs, uncertainty, technical constraints, political intervention, and unpriced externalities. Drom (2014) suggests that there is little empirical evidence that capacity markets result in lower electricity costs for consumers, such as by expanding the number of available generators.

The PJM and NYISO use a demand curve capacity auction, where an administratively or centrally set demand curve is established. With a demand curve capacity auction, the price of capacity increases as the demand for such capacity increases, with the price that load serving entities (LSE) will pay for various quantities of capacity being established, with the final price that LSEs pay in this type of auction being the clearing price (Miller et al., 2012). The author defines buyer-side mitigation as offer floors that have been put in place by the FERC to deter large net buyers and local governments from subsidizing new entry and artificially depressing capacity market prices. Morrison (2016) writes that buyer-side market power mitigation has been implemented by FERC to improve capacity markets' long-term performance by meeting load-serving entities' needs for diverse resource portfolios, enabling states' efforts to pursue policy goals, satisfying generators' need for stable revenues, and ensuring resource adequacy. However, the author continues that buyer-side mitigation cannot serve the FERC's goals because the centralized capacity constructs to which they have been appended are inherently incapable of doing all that the FERC asks of them. Bilateral capacity markets and LSEs' self-build options must be included in centralized capacity schemes.

In terms of improving capacity markets, in order to better reflect transmission constraints, RTOs in the U.S. have periodically changed the boundaries of capacity zones in their regions. The design of the auction can also be changed; in 2014 and 2015, ISO New England and PJM received approval from FERC to modify their capacity markets to better ensure that power plants with capacity commitments were available to generate electricity when they agreed to be. Reasons for differences in capacity auction prices include: differences in the availability and type of resources across regions, differences in regional energy market and fuel prices, and differences in overall market design (US GAO, 2017).

Interaction of Inaccurate Capacity Credits

- A) Energy Price Caps
 - B) Renewable Portfolio Standards
 - C) Renewable Energy Tax Credits
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- 1) Generation Mixes
 - 2) Efficiency Losses
 - 3) Distortions among Competing Wind and Solar Developments

Inaccurate or lower capacity credits can result because energy price caps distort the true cost of electricity, and thus create a missing money problem by diverting resources away from the energy generation source. Renewable Portfolio Standards (RPS) require that a specified percentage of the electricity utilities sell comes from renewable resources. Renewable energy tax credits are a variety of indirect federal subsidies to finance the investment and production of renewable energy. The generation mix is the combination of thermal and renewable generators, while efficiency losses result from using thermal over renewable sources. Waste heat that diverts most of the energy creates efficiency losses in electricity generation from burning fuel to generate electricity. Around two-thirds of the original energy is lost in the process for thermal

generation. Renewables like wind, solar, and hydroelectricity don't lose energy because they don't need to convert heat into motion.

Capacity factors are typically 15-25% for solar, 25-35% for wind, and 100% for thermal generators. Lower values can be used for intermittent and hydro renewable power plants reflecting their lower average availability, with thermal plants at 100%. Overinvestment may result from too much capacity credit, which is an implicit subsidy, while investment could be diverted away from a resource with a low capacity credit. Bothwell and Hobbs (2017) suggest that inaccurate capacity credits can subsidize or penalize different resources, and consequently distort investment between renewables and non-renewables, and also among different types and locations of renewables. Endogenous capacity additions determine the amount of capacity credit, with the capacity value defined as the fraction of the rated capacity considered firm for the purposes of calculating the module reserve margin. Imported electricity may have no firm capacity, so some plants assumed to have no firm capacity can even have zero values.²

Affect Capacity Auctions

- 1) Increasing share of renewable energy
- 2) Varying carbon emission costs
- 3) Existing capacity mix

The increasing share of renewable energy is affecting capacity auctions for capacity markets because they are \$0 bids, which exacerbates the issue of long-term investment for generators. These \$0 bids drive down prices, which results in less money available for investment, or missing money. Varying carbon emission costs are affected by carbon emissions caps set by the government, and result in higher prices at auction. The existing capacity mix between renewables and thermal, base-load and peak-load, can also affect prices at capacity auctions.

Four Functions of Capacity Markets

- 1) Provide capacity payments as reservation payments to ensure that a generator will be able to provide energy over a specified period of time, to meet peak load plus a reserve margin
- 2) Missing money from capacity market; capacity revenues can provide generators with the missing money when they do not receive enough money to cover fixed and variable costs from selling energy and ancillary services; aggravated by the introduction of renewable energy generators
- 3) Capacity payments provide an incentive for new entrants to locate in regions where there is a need for additional resources
- 4) Price signals to build new power plants or reduce demand

Functions of Capacity Markets

- 1) Maintain reliability
- 2) Encourage the economic development of new capacity resources
- 3) Moderate electricity price swings

² Leap Help, retrieved May 7, 2023, https://leap.sei.org/help/Transformation/Capacity_Value.htm

- A) Meet peak load demand
- B) Provide adequate reserve margins

Capacity Market Design Issues

- 1) The role of demand response
- 2) Whether locational constraints should be imposed
- 3) How far forward such markets should be run
- 4) Whether separate markets should be created for flexible capacity to back up intermittent renewables

Ways to Improve Capacity Reserves

- 1) Energy storage
- 2) Improving market design
- 3) Enhancing system operation

There are three ways to improve capacity reserves: energy storage, improving market design, and enhancing system operation. Energy storage can be facilitated through the use of renewable resources and batteries to store their power, like wind and solar. Market design can be improved by focusing on demand side and supply side characteristics. For example, the demand side in the PJM is characterized by energy efficiency resources and demand resources. Energy efficiency (EE) resources are load resources which are designed to achieve a continuous reduction in electric energy consumption during peak periods, and receive the clearing price in an Reliability Pricing Model (RPM) auction as generation capacity. Demand resources (DRs) are interruptible load resources that receive the clearing price in an RPM auction as generation capacity.³ The NYISO identifies the supply side of capacity markets into three categories: 1) installed capacity suppliers (ICAP Suppliers) 2) capacity suppliers with duration limitations, and 3) other capacity suppliers.⁴ Power plants must find the resources to upgrade the electric grid periodically, and thus system operation can be enhanced with new and improved electrical resources, often financed via capacity payments.

Goals of Capacity Markets

- 1) Remunerate new electrical generators
- 2) Reduce investment risks
- 3) Avoid electricity blackouts

Capacity markets have three primary goals: 1) remunerate new electrical generators 2) reduce investment risks, and 3) avoid electricity blackouts. They remunerate new electrical generators by ensuring a capacity payment to ensure new investment in future plant assets. New investment from capacity payments serves to reduce investment risks, because instead of

³ Bowring, J. (2013) The Evolution of the PJM Capacity Market, *Evolution of Global Electricity Markets*

⁴ Lavillotti, M. and Smith, Z. (2019). DER Energy & Capacity Market Design, <https://www.nyiso.com/documents/20142/6128534/04%20DER%20Market%20Design%20Presentation.pdf/f457a835-9a6c-5281-fa1f-35683282f5df>

having to rely on internally generated funds, the electric utility is getting an external payment for its investments. Avoiding electricity blackouts is another function of capacity markets, in that the capacity market prevents power outages when demand for electricity is high by determining how much power is needed and where it should be located. A region's peak total energy usage for the year, plus a reserve, is predicted with formulas. Expensive, fossil-fueled power plants provide the reserve, and thus electric customers often end up paying too much for thermal power they don't need. A 2020 Sierra Club study found consumers are paying \$4.4 billion in over-procurement costs to keep 77 gas and coal plants online in PJM territory.⁵

Design Elements of a Capacity Remuneration Mechanism

-Ilak et al. (2021)

- 1) Market orientation
- 2) Insurance of long-term power system adequacy
- 3) Optimal cross-border generation capacity utilization

Market orientation refers to the supply and demand of electricity. The objective of a capacity remuneration mechanism is to propose a financially fair pricing mechanism that will guarantee enough new capacity and not present state aid (Ilak et al., 2021). The author continues that generation adequacy means ensuring that in the medium and long term the power system can supply the aggregate electricity demand at all times while accounting for scheduled and reasonably expected unscheduled outages of power system elements. Cross-border effects must be managed to ensure that capacity markets do not increase electricity prices in neighboring regions that lack capacity markets. Lambin and Léautier (2019) find that capacity markets may spread due to their negative cross-border effect on investment incentives, and that a capacity market is ineffective unless transmission capacity is small, if TSOs and RTOs can't reduce export capacity and neighbors stay energy-only. Further, If TSOs and RTOs can reduce export capacity, the capacity market attracts investments and security of supply (SoS) of non-domestic markets shrink. Thus, a neighboring energy-only or strategic reserve market will be influenced in the long-run and may have to implement a capacity market in order to meet its SoS standard.

Ilak et al. (2021) Design Elements

- 1) Security of supply
 - 2) Different amounts of newly installed firm capacity
 - 3) Different short-run marginal costs of newly installed firm capacity
 - 4) Different capacity factors of newly installed firm capacity
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- A) Electricity prices
 - B) Electricity load

⁵Citizens Utility Board. (2022). CUB explainer: What are Capacity Markets?
<https://www.citizensutilityboard.org/blog/2022/07/22/cub-explainer-what-are-capacity-markets/>

Capacity factor is the measure of how often a power plant runs for a specific period of time, which is expressed as a percentage and calculated by dividing the actual unit electricity output by the maximum possible output, and indicates how fully a generator's capacity is used.

Regulatory Designs

-Le Coq et al. (2017)

- 1) A baseline price cap system that restricts scarcity rents
 - 2) A price spike regime that effectively lifts these restrictions
 - 3) A capacity market that directly rewards the provision of capacity
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- A) Market design
 - B) Capacity provision
 - C) Pricing in electricity markets.

Le Coq et al. (2017) defines three available regulatory designs for an electricity market to price its electricity. One, a baseline price cap system that restricts scarcity rents. Scarcity rents represent the market mechanism needed to signal resource shortages and provide incentives for new investment in resources. Two, a price spike regime that effectively lifts these restrictions, which allows for higher prices to provide for investment funds. Three, a capacity market that directly rewards the provision of capacity. The author notes that capacity markets often aim at capacity levels of around 115% of peak load.

Calculations Taken into Account in Reserve Margins

- 1) Normal maintenance problems
- 2) Extreme acts of nature (hurricanes and ice storms)
- 3) Unanticipated losses of fuel (delivery limitations)
- 4) Any variable that may prevent generation assets from being fully available during peak demand periods

The reserve margin is calculated at peak load for a power plant as a percentage of total capability, as the amount of unused available capability of an electric power system. There has to be adequate reserve capacity to meet demand when normal maintenance problems cause the generator to be down, until the generator is fixed.

III. Economics of Electricity

There are two markets for electricity. One, the wholesale energy-only market where electricity is sold on the spot, intraday, and future markets. Two, the capacity market, where capacity auctions are the equalizing market which ensures short-run security of supply and long-run investment of resources. In the energy-only market, there are problems of long lead times for generation investments, and also market equilibrium cannot be reached due to the absence of demand response. As a consumer good, due to the costly nature of power interruptions, there are high requirements for security of supply for electricity, which can be considered in the context of The value of lost load (VoLL), which expresses a consumer's willingness to pay for an uninterrupted supply of electricity (Pugl-Pichler et al., 2020). Different ways to consider energy

security and the security of electricity supply, all with the ultimate goal of uninterrupted, stable supply at the lowest cost, are: fuel adequacy, generation capacity adequacy, balancing and flexibility, and network adequacy (Cherp and Jewell, 2014). Leiren et al. (2019) suggests that resource adequacy in electricity markets can emphasize supply-side elements such as generation infrastructure, transmission interconnectors, and demand-side responses and energy efficiency.

In the energy-only market, in order to finance the operational and fixed costs by stimulating adequate investment on the supply side, market prices must be high enough. Bublitz et al. (2019) state several market-related and physical barriers to generation adequacy in the energy-only market. Market-related barriers in the energy-only market include: price caps, the inelasticity of demand for electricity, and supply side balancing of the electricity market. Physical barriers to generation adequacy include: balancing of consumption and generation, battery storage, the free-rider problem and reliability contracts, and spot market clearing process and fulfillment for short-term trading. In the energy-only market, other issues affecting generation adequacy include: the merit order effect of renewables and the resulting missing money problem, and the phase out of certain fuel types and technologies.

Cepeda and Finon (2011) write that the energy-only market is sufficient to meet generation adequacy demands if three economic conditions are met: (1) the market is perfectly competitive, (2) market participants have rational expectations, and (3) follow a risk-neutral strategy. Schwenen (2014) suggests, however, that since electricity markets are oligopolies, these three assumptions usually do not hold. Investment cycles of over- or under-investment may also result because investors do not have rational expectations (Ford, 2002). Another problem with the energy-only market is that investors build less capacity than is needed, because they are risk-averse (Neuhoff and de Vries, 2004). Gailani et al. (2020) notes that the energy-only market assumes that energy demand and supply are always balanced, and thus it neglects the energy adequacy problem. This means that the demand response and market clearance must be considered, though since demand is inelastic they cannot be guaranteed in the energy-only market when the supply side becomes scarce, and there is a need for a load reduction from the demand side to ensure market clearance. Another problem with energy-only markets is that due to price caps, generators do not earn money in blackout events, despite the scarce capacity and peak demand. Pugl-Pichler et al. (2020) notes the energy policy objective triangle of affordability, sustainability and security of supply, which is espoused in the European Union, to provide customers with a secure, clean, and affordable supply of electricity.

Söder et al. (2020) discuss the different factors to consider to evaluate capacity reserves and system reliability, in an adequacy assessment performed by the RTO or TSO, including: for 1) different time horizons (week-ahead, seasonal, mid-term, years-ahead) 2) scenarios (normal conditions, rare extreme weather conditions, different forecasts of load growth, political agendas), and 3) approaches (hourly, stochastic, probabilistic). Reliability standards include the Loss of Load Probability (LOLP) (0.1) or the Loss of Load Expectation (LOLE) (1 day in 10 years). The Expected Energy Not Served (EENS) is an energy-related reliability factor which captures the severity of the outages in terms of the energy that is shed. The Loss of Load

Frequency (LOLF) and the Loss of Load Duration (LOLD) are time-dependent reliability factors which capture the expected frequency and duration of outage events. A “loss of load event” is defined as: “an event where the system requires import, if available, from outside the area/country in question to serve the demand.”

Value of Lost Load (VoLL) is a cost-benefit analysis which can be applied to derive some of the reliability standards based on adding more capacity beyond a certain level of reliability and the resulting observations of the decreasing marginal value. Value of Lost Load (VoLL) as a metric represents the direct monetary value of customer damage from an outage event. Söder et al. (2020) suggests that VoLL is hard to estimate, because it is highly dependent on the timing, the frequency, and duration of an outage, and varies from customer to customer. The author continues that the implementation of the different reliability standards by the local regulators can vary with several factors, including: 1) subjective input assumptions 2) modeling methods, and 3) choice of sensitivity analyses. Reliability standards can also differ between jurisdictions for issues such as: 1) which units are included in the adequacy evaluation 2) whether the demand is considered to be price sensitive, and 3) whether the reserves are included. Reliability standards are often not seen as a legally binding target, rather as a worst-case lower bound.

Characteristics of Electricity

-Bernstein (n.d.)

- 1) Consumers require electric power on demand in volumes that fluctuate over the course of the day, week and year.
- 2) Electricity, because it cannot be stored economically, must be generated simultaneously with its consumption; supply and demand must thus be maintained in instantaneous and continuous balance.
- 3) The balance of supply and demand is maintained across a common power grid; generators of electricity supply the common grid, and consumers of electricity draw their power from it.
- 4) An imbalance between supply and demand on the grid of even a few minutes' duration can cause a system blackout. The actions of individual generators and consumers to supply or withdraw power from the grid can thus affect the reliability of supply to all consumers.

Electricity Markets, Homogenous Good Auction Types

-Vasin et al., (2013)

- 1) Uniform price auction; Producers submit their supply functions that determine the amount of supplied good depending on the market price. These bids are typically sealed, in that they are not revealed to the other agents until the auction closes. The cut-off price balances the total supply and demand, and each agent sells or buys at this price according to their bid.
- 2) Pay-as-bid auction; Differs in that each producer gets payment according to their bid while consumers pay the average price of the good.

Wholesale Electricity Market Principles

-Panfil and Zakaria (2020) discuss wholesale electricity market principles.

- 1) Wholesale market revenues should predominantly flow from well-designed energy and ancillary services markets.
- 2) When altering market design, FERC and ISOs should focus on only those services that are clearly needed and ensure that any market design change does not unduly discriminate between resources.
- 3) Minimize interventions that distort transparent and accurate pricing.
- 4) The just and reasonable standard strongly favors rate decreasing outcomes.
- 5) FERC and ISOs should facilitate and not undermine state public policy preferences.

As a commodity, electricity is the only commodity which can be delivered to customers with a separate capacity payment in the presence of a capacity market. Electricity supply has to be stored to be released when demand arises, which makes electricity different from other market goods. The infrastructure to create and store electricity, as well as market mechanisms to regulate its price such as price caps, have to be considered. Electricity is like healthcare in that it has inelastic demand, which means that demand is not dependent on price, and people will pay more money for electricity if they have to.

A reserve market is a market for consumer goods where we need to have sufficient investment resources to produce them when needed and during peak demand. In a reserve market the producer sells the availability of its generation capacity in return for payment. The capacity market in which electricity producers offer their power plant availability is a reserve market. The electricity energy-only market is sometimes not sufficient to provide adequate investment for generation reserves, because it relies on private incentives, or wholesale prices. Monjoie (2021) lists reasons for this inefficiency of the energy-only market, including: fixed costs, uncertainty, technical constraints, political intervention, and unpriced externalities.

Problems Facing Energy-Only Markets

- 1) Asymmetric information resulting in price caps
- 2) High investment risk for generators

Schäfer and Altvater (2019) note that energy-only markets face two problems: 1) asymmetric information resulting in price caps, and 2) high investment risk for generators. One, asymmetric information results when scheduled maintenance or market power is used to create a scarcity event, and price caps are consequently used. Price caps in energy spot markets prevent market power misuse during high demand, and are a result of asymmetric information. The peak energy rent (PER) being cut when the price cap is too low, and missing money to cover capital costs results. The optimal price cap is not standardized and depends on the spot market level, has a negative relationship with asymmetric information, and might result in missing money or in market power misuse. Two, there is a high investment risk for generators, in that response to scarcity events determines whether capital costs are covered by grid operators. The number and intensity of scarcity events are in part determined by the actions of other electricity producers, are not predictable, and are volatile.

Market Failures for which Capacity Markets Must Compensate

CRMs assume that in electricity markets the energy spot markets for energy are characterized by two market failures for which capacity markets must compensate (Bhagwat et al., 2016).

- 1) Missing money problem- The missing money problem is a situation in an energy-only market where low prices and few price spikes do not provide sufficient long-term investment incentives in new generation capacity. Price caps result in an absence of shortage, or scarcity, pricing, and consequently energy and ancillary service prices may fail to reflect the full value of energy generation, which might result in underinvestment in capacity and inadequate remuneration for investors.
- 2) Absence of a long run contract market- A long run contract market might be necessary to induce risk-averse investors to build new, long lived generation capacity. The additional revenues from capacity markets result in stronger investment price signals for new generation capacity additions.

Reasons for Capacity Mechanisms, the Missing Money Problem

Lynch and Devine (2017) discuss reasons why low-load reserve units would not prove viable in the absence of a capacity remuneration mechanism.

- 1) The absence of an active demand-side in electricity generation markets, which means that consumers cannot signal their desired level of reliability of supply (Cramton and Stoft, 2005). There is therefore a weaker price signal for reliable supply, and consequently for electricity generation capacity.
- 2) The shared nature of the electricity network, which introduces a 'free-rider' problem, whereby it is not possible to differentiate between consumers who had entered into a contract for reliable supply.
- 3) Price caps.
- 4) Electricity has public good characteristics (Abbott, 2001), and so policy-makers may be reluctant to leave the secure supply of generation capacity to market forces.

Why Price Spikes have failed to provide the necessary incentives for generators to invest

-Bernstein (n.d.)

- 1) First, power plants take years to develop and build, so price spikes during periods of scarcity occur too late to provide a timely signal to developers that capacity additions are required.
- 2) Second, price spikes are triggered by capacity shortages; their very occurrence, in other words, signals an inadequate supply of capacity on the system and thus an increased probability of power cuts.
- 3) Finally, price spikes are often subject to mitigation measures by independent system operators that limit the revenues available to recover capital invested. These measures include price caps designed to limit the exercise of market power by generators during periods of capacity scarcity; bidding rules that restrict bids too far in excess of cost; and the granting of special, out-of-market uplift payments to plants whose capacity is essential to system reliability ("reliability-must-run" units) that benefit these plants but create no revenues for other inframarginal generators.

The capacity market is the missing money from the energy-only and ancillary services markets, in the context of the wholesale energy market. Two of the functions of capacity markets is to prevent a black swan event, the widespread loss of power to many customers, and the missing money problem, or lack of sufficient investment in generation resources. A black swan event, a lack of sufficient generating capacity, rarely occurs, because generation-capacity deficiencies are not common in America. Customer electricity loss has a low probability in the modern electric grid on this planet due to the extensive number, size, and diversity of generation capacity. Consequently, disregarding the black swan event, the primary function of the capacity market is solving the missing money paradigm, where investment in new resources is lacking, or there is a failure to meet long-term revenue requirements. In the missing money problem, electricity market revenues are too low to cover the total costs of power generation units, including investment, fixed, and sunk costs. The missing money problem is created when price caps in times of scarcity lower spot market prices for electricity, and is exacerbated by the increased use of renewable energy sources and the merit order effect whereby the marginal cost, or fuel cost, of renewables is 0. Komorowska (2021) further defines the missing capacity dilemma, where the market signals do not provide a sufficient incentive for investors to build new power units.

There are two ways to address the missing money problem in electricity markets. One, the price-based approach in the energy-only market, is to raise scarcity prices paid during blackouts. Two, the quantity-based approach in the capacity market, is to pay every supplier of capacity the same amount per MW of capacity.

Measuring Security of Electricity Supply

-Cherp and Jewell (2014); Goal of uninterrupted, resilient supply at the lowest possible cost

- 1) Fuel adequacy
- 2) Generation capacity adequacy
- 3) Balancing and flexibility
- 4) Network adequacy

Ways to Measure Electric System Adequacy

- A) Loss of load probability, 1 day in 10 years for North American grid; an outage, some customer loads are not being served
 - B) Expected unserved energy
-
- 1) Spot market energy prices
 - 2) Bilateral energy contracts

Loss of load describes the situation when in an electric grid the system load is greater than the available generation capacity. Loss of Load Probability (LOLP) is a probabilistic reliability index of a loss of load occurring within a year. Loss of load events are calculated before the mitigating actions, such as purchasing electricity from other systems or load shedding, are taken, so a

blackout does not necessarily result from a loss of load.⁶ Expected unserved energy (EUE) is the expected amount of energy not supplied by the generation system, due to capacity deficiency.

The energy spot market is a commodities market where the energy commodity is sold for cash and is delivered to a specific location, either on the day of the sale or on the day after the sale. The spot price tells generators how much electricity the market needs to keep the electric grid in balance at a moment in time. When the spot price is decreasing, thermal peaking generators turn down or off, and when the spot price is increasing, thermal peaking generators ramp up their output or turn on. In electricity markets, spot markets include: 1) day-ahead energy 2) intra-day energy, and 3) real-time energy. Market participants in spot markets include wholesale marketers, brokers, suppliers such as gas producers and electric generators, utilities, large consumers, and retail marketers. Spot transactions are often performed using centralized exchanges or Independent System Operators (ISOs).⁷ A bilateral contract is a private trade between two parties, and occurs either on the phone or via electronic trading exchanges. Shorter transactions commonly use electronic exchanges such as the Intercontinental Exchange (ICE), while longer transactions are negotiated face to face. A bilateral trade specifies key terms including delivery point, volume, time of delivery, price, and whether the transaction is firm.⁸

IV. Merit Order Effect of Renewables

The equilibrium generation mix should meet reliability and environmental standards. As markets have evolved, a primary goal of modern electricity generation is to provide a cost-conscious portfolio of resources that meet reliability and environmental standards, which means that an electricity provider must manage the intersection of traditional thermal generators and renewable generators. Government regulators must issue coordinated mandates that push for more renewable generators and balance the needs of the modern electrical society between reliability and environmental standards of thermal and renewable sources. We must strive to create a generation mix that includes more renewable energy sources that don't have the efficiency losses of converting fuel into heat that thermal generators have. There are also distortions among competing wind and solar projects, as renewable sources compete against each other for government tax subsidies.

The contribution of renewable energy sources to the electric grid is more intermittent than thermal power sources; therefore, the capacity value of renewables is smaller than that of conventional thermal plants. In terms of capacity value, Söder et al. (2020) suggests that this term more accurately captures a generator's contribution to the generation capacity adequacy of a power plant than by its installed capacity through considering factors such as: 1) forced or planned outages 2) seasonal ratings, and 3) temporally limited primary energy supply. The

⁶ Wikipedia, retrieved September 29, 2022, https://en.wikipedia.org/wiki/Loss_of_load

⁷ Energy Knowledge Base, retrieved May 5, 2023, <https://energyknowledgebase.com/topics/spot-market.asp>

⁸ Energy Knowledge Base, retrieved May 5, 2023, <https://energyknowledgebase.com/topics/bilateral-electric-contract.asp#:~:text=A%20bilateral%20contract%20is%20a.or%20via%20electronic%20trading%20exchanges.>

capacity value of a new generator is the maximum amount that the load in the system, including this generator, can be increased by while keeping the reliability of the system at the same level as before this generator was included (Garver, 1966).

Three markets are the energy, capacity, and renewable credit markets. Traditionally the third market is known as the ancillary services market, though the emergence of the renewable credits market must be considered. Renewable credit markets include diverse factors such as renewable generator capacity and the subsidies and tax schemes that promote their investment. The U.S. Energy Information Association projects that renewables share of the generation mix will double from its current 21 percent to 42 percent by 2050 (Wells, 2021).

The impact of renewables on the energy markets is evident through falling wholesale electricity prices and lower investment stability (Leiren et al., 2019). De Miera et al. (2008) notes the merit order effect of renewable energy in energy markets, where eventually the average spot price level will decrease in the energy-only market. This economic concept concerns how the average spot price in the energy-only market is affected by the marginal costs of different forms of electricity. Spot markets with perfect competition inherently utilize marginal costing, with renewable energy sources displaying lower marginal costs because they do not face fuel costs. Energy markets have inelastic demand, which means that the same amount of energy is needed regardless of price, and thus the more energy is secured from renewable sources the less is needed from traditional peaking thermal sources. An increase in one energy source results in a decrease in the other energy source.

Base-load power plants run constantly, while peak-load power plants run only in times of high demand. Flexible plants for peak-load services which can ramp up and down quickly at a low cost, such as gas or coal, are needed to balance intermittent renewable base-load plants. Schäfer and Altvater (2019) suggest that this interaction between renewables and fossil fuels generators means that the merit order effect of renewable energy creates a price signal in spot markets in the short run which counteracts the optimal capacity mix with more flexible power plants in the long run. Wissen and Nicolosi (2008) suggest that the merit order effect will vanish in the long run because at a certain point missing flexibility will lead to increasing spot prices when the power plant mix adjusts. Mays et al. (2019) notes that CRMs favor peaking technologies like coal, oil and gas over wind, solar, or nuclear technologies.

Schäfer and Altvater (2019) theorize that In an energy-only market with perfect competition, all generators bid prices corresponding to their marginal costs, with bids ordered from lowest to highest, which forms the merit order. In spot market auctions in the energy-only market uniform pricing is determined, which means that the electricity price is set by the last power plant needed to satisfy demand. Electricity generators except for the price-setting generator gain the infra-marginal rent (IR), which is used to cover capital costs, with the price-setting generator varying over time with supply and demand. Peak-load power plants display lower capital costs and higher marginal costs than base-load power plants, and consequently gain an IR less often.

A peak energy rent (PER) in times of scarcity covers the capital costs of the peak-load generator, with peak-load plants forming the right end of the merit order and consequently never achieving an IR. All power plants gain a PER when demand is high and supply is limited, because the spot price rises above the marginal costs of the last generator in the merit order. Caramanis (1982) suggests that price signals in the context of IRs and PERs of an ideal energy-only market are sufficient to cover generators' capital costs and create capacity investments.

Renewable Energy Tax Credits

Under the Consolidated Appropriations Act of 2021, the renewable energy tax credits for fuel cells, small wind turbines, and geothermal heat pumps now feature a gradual step down in the credit value, the same as those for solar energy systems.

Tax Credit:

- A) 30% for systems placed in service by 12/31/2019
- B) 26% for systems placed in service after 12/31/2019 and before 01/01/2023
- C) 22% for systems placed in service after 12/31/2022 and before 01/01/2024

V. Economics of Deregulated Markets

Wholesale electricity markets have been implemented in favor of regulated monopolies in the energy sector around the world, including in the United States. A deregulated electricity market system encounters issues in recovering operating costs through electricity rates, because the recovery of the cost of maintaining system reliability through rates is compromised, for two reasons. One, the cost of system reliability is a fixed cost. Two, system reliability is a common good, from which no one can be held accountable but all consumers benefit. Consequently, it is not given that in a competitive, or deregulated, electricity market the plant operator can recover investments in reserve capacity or fixed or sunk costs, which is necessary to ensure system reliability. In liberalized markets the responsibility for adequacy determination and system reliability is not concrete, and could fall to either the plant operator, the regulator, or the customer. In the United States, much new power plant capacity was built in the 1980s when deregulation gained steam, though all that spare capacity along with the associated transmission has been maximized. In the future, renewables will be the largest generation source, supported by natural gas and nuclear. Liberalization of the electricity industry brought about the introduction of market-based mechanisms to replace national planning, including capacity remuneration mechanisms to directly remunerate installed capacity (Lambin and Léautier, 2019).

Issues with Liberalized Electricity Markets

- 1) Increasing energy demands, fast demand growth
- 2) Decommissioning of conventional power plants
- 3) Steady growth of renewable energy sources, RES

One, fixed or sunk costs for generation capacity means that much of the capital invested in a plant assets is expected to go unutilized. In a regulated environment, electricity rates are set to cover both fixed and variable costs of the average cost of supply, and thus also provide for recovering the initial generation investment, or sunk costs. In a competitive deregulated market different suppliers bid prices down to reflect the variable costs of supply, with no allowance for sunk costs. Two, system reliability is a common good, from which individual consumers are not held responsible but one in which all consumers benefit. Consumers can choose their supplier from whoever offers the best price in a competitive deregulated market. The best price implies that customers are not paying their fair share for system reliability, or fixed costs in the form of generation capacity. Regulated monopolies in the form of utilities appease this problem of securing fees for fixed costs, as customers have to pay rates that allow the utility to recover its cost of system reliability.

VI. Results

Tables 1 and 2 show the results of the regression analysis finding significance of different energy variables with world GDP and world population since 1965. Table 1 uses values for fuel sources since 1965, and Table 2 uses values for fossil fuels since 1998. Other renewables, biofuels, solar, oil, coal, and traditional biomass are significant with world GDP since 1965. Other renewables, hydropower, nuclear, oil, coal, and traditional biomass are significant with world population since 1965. Brent oil, China coal, Japan coking coal import, and Nigeria oil are significant with world GDP and world population since 1998. All data was taken from Our World in Data.

Coal Indices

- 1) Asian Marker Price Coal
- 2) China Qinhuangdao Spot Price Coal
- 3) Japan Coking Coal Import CIF Price
- 4) Japan Steam Coal Import CIF Price
- 5) Japan Steam Spot CIF Price Coal
- 6) Northwest Europe Coal
- 7) US Central Appalachian Coal Spot Price Index

Oil Indices

- 1) Brent Crude
- 2) Dubai Oil
- 3) Nigerian Forcados Oil
- 4) West Texas Intermediate Oil

Natural Gas Indices

- 1) German Import Natural Gas
- 2) Canada Alberta Natural Gas
- 3) LNG Japan CIF
- 4) UK NBP (ICIS NBP Index) Natural Gas
- 5) US Henry Hub Natural Gas

Graph 1 shows the worldwide fuel diversity consumption for 2022. Coal is the leading resource being used still, at 35.8%. This figure is contrasted with Table 3, which shows U.S. fuel diversity, where natural gas is the leading resource used. Natural gas is number two worldwide, whereas coal is number two in the United States. These results show how the United States has made a concerted effort to diversify from coal plants in recent years to more clean burning natural gas. Number three worldwide is hydro power, followed by nuclear at four and wind at five. In the United States, all three, hydro, nuclear, and wind, are about equal. Solar is still making inroads both worldwide and in the U.S.

Table 5 and Graph 3 show the fuel diversity and energy generation portfolio of Texas ERCOT from 2014 to 2022. Coal and natural gas were almost even in 2014, but natural gas is more than twice coal by 2022. Wind is second in Texas, followed by coal, nuclear, and solar. Tables 8, 9, and 10 show NYISO energy sources from 2014 to 2020. In the NYISO, natural gas is the biggest resource source, at 35%, followed by nuclear use at 29%. Hydro power is third in the NYISO at 22%, followed by wind at 3%, coal at 1%, and solar at 1%. The NYISO is ahead of the market in weaning itself off coal, though still has not embraced large-scale wind power.

Table 6 shows the output-weighted average price by generation type based on the generators' specific locational prices in 2022 for Texas ERCOT. Gas peakers is the highest cost at \$189.86 per MWh, followed by gas steam at \$140.51 per MWh. Coal is relatively cheap, only costing \$70 per MWh. Wind is the cheapest, at \$34.09 per MWh, and solar is \$73.09 per MWh. Nuclear is also relatively cheap, only costing \$60.78 per MWh. Hydro costs \$87.76 in 2022 per MWh. If coal is cheaper, then we could benefit from using more coal, even though coal produces more emissions for the environment.

Per Table 7, NYISO does not report prices per fuel source in either the Gold Book on the NYISO website or in their annual market reports in Potomac Economics. They do report natural gas prices per zone using indexes, which averaged to around \$7.50. In 2022, average all-in prices rose to the highest levels observed in more than a decade, ranging from \$58 per MWh in the North Zone to nearly \$127 per MWh in Long Island. All-in prices rose 50 to 100 percent from 2021.

Tables 8, 9, and 10 show NYISO energy sources per GWh and percent from 2014 to 2020. Coal use decreases from 3% in 2014 to 1% in 2020. Nuclear use remains constant at around 30% use from 2014-2020. Solar is 1% and wind is 3% in all years, and natural gas use is around 35% in all years.

Table 11 and Graph 4 show PJM Interconnection wholesale costs from 2018 to 2022. For 2022, energy market cost is \$54.16 per MWh, capacity market cost is \$11.71 per MWh, and total cost is \$79.37 per MWh. 2022 was the most expensive year since 2018.

Table 12 and Graph 5 show 2014 fuel diversity for capacity markets for the 6 RTOs, not including Texas ERCOT. These include ISO-NE, CAISO, MISO, NYISO, PJM and SPP. Table 13 and Graph 6 show 2014 fuel diversity for the energy-only market. This information is obtained from a singular 2015 ISO/RTO Metrics Report, which was only published for that year, and was published by the New England States Commission on Electricity. The fuel mix for capacity markets and energy-only markets mirror each other. For coal, MISO, PJM, and SPP each use coal for around 50% of their energy mix. CAISO used 0% coal, NYISO uses 3% coal, and ISO-NE uses 5% coal. These are major differences from our cheapest fossil fuel energy source, coal. Natural gas use is significant in all 6 markets. Nuclear use is around 30% in ISO-NE, NYISO, and PJM, and nuclear use is around 10% in CAISO, MISO, and SPP. Hydro and renewables use is significant in ISO-NE, CAISO, NYISO, and SPP.

Tables 14-17 display capacity auction results from the four U.S. capacity markets. Table 18 displays that PJM Interconnection is the largest capacity market in the U.S., followed by Midcontinent ISO, with NYISO and ISO-NE being about the same size. Per Table 19, energy costs were highest in CAISO and Lowest in SPP for 2018.

VII. Conclusion

China has said that regarding its use of coal fired power plants, it is important to embrace the future, but we cannot forget the past at the same time. In Texas ERCOT, coal is the cheapest form of fossil fuel energy, at \$70 per MWh compared to natural gas at \$140.51 per MWh. It is also relevant to note that wind energy has not caught on and advanced in all U.S. regions at the same pace. In 2020, wind usage nationwide was at 9.8% and solar usage was at 4%. In 2014, CAISO used 0% coal and 29% hydro and renewables. The 0% coal is significant, because it represents a clear denunciation at an early date from a major zone in use of our cheapest fossil fuel energy source. Capacity markets have emerged since deregulation as a means to secure system reliability and maintain operating reserves, but are needed in every market. In some markets, like Texas ERCOT, they utilize the energy-only market by itself to generate sufficient revenues for plant generation investments. Europe is a similar situation, with a few countries utilizing capacity remuneration mechanisms but some still only using energy-only markets. Thus we can say that having a capacity market or using CRMs at all is a political decision, and not needed in every situation.

Table 1. Fuel Source Significance per GDP and Population

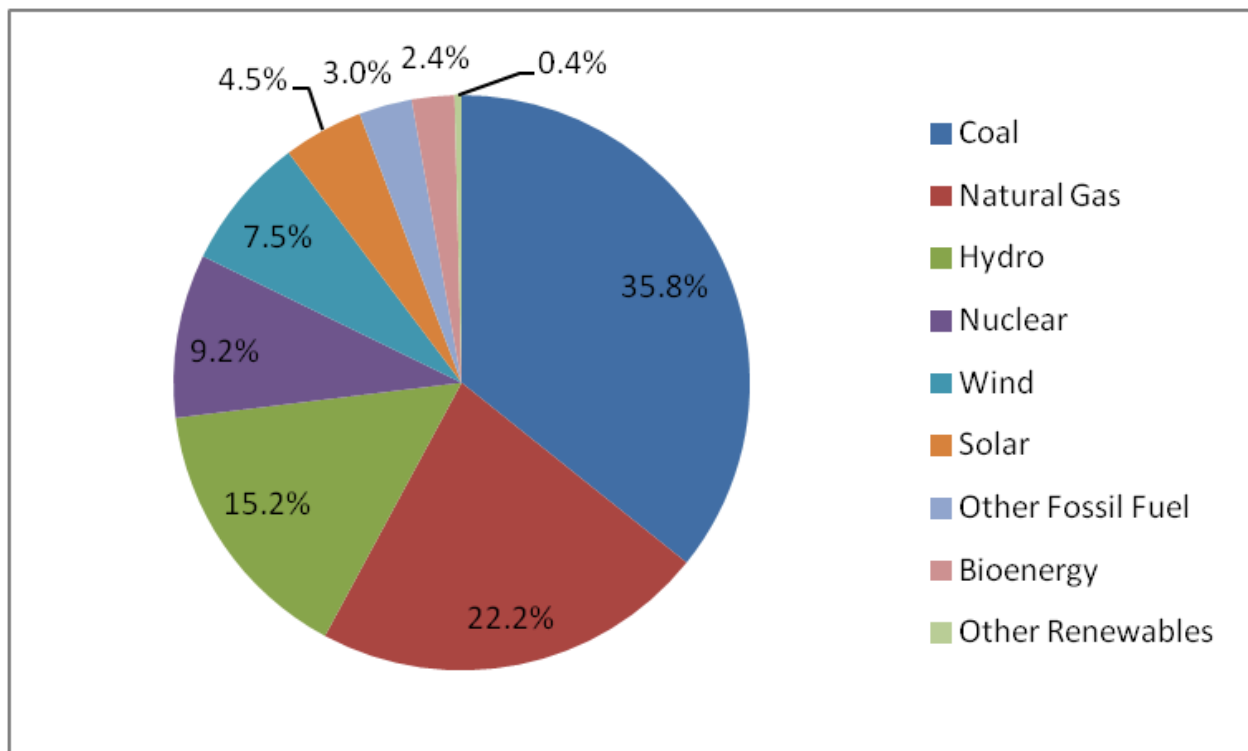
Variable	GDP		Population	
	Estimate	Significance	Estimate	Significance

Other renewables (TWh, substituted energy)	5.77	***	3.18	***
Biofuels (TWh, substituted energy)	-1.76	*		
Solar (TWh, substituted energy)	-2.64	**		
Hydropower (TWh, substituted energy)			6.74	***
Nuclear (TWh, substituted energy)			3.22	***
Oil (TWh, substituted energy)	3.86	***	3.52	***
Coal (TWh, substituted energy)	6.08	***	4.5	***
Traditional biomass (TWh, substituted energy)	3.08	***	6.12	***

Table 2. Fossil Fuels Significance per GDP and Population

Variable	GDP		Population	
	Estimate	Significance	Estimate	Significance
Brent Oil	-2.09	*	-1.99	*
China Coal	1.85	*	2.03	*
Japan Coking Coal Import	-2.28	*	-2.36	**
Nigeria Oil	2.16	*	2.05	*

Graph 1. Worldwide Fuel Diversity 2022



Source: Statista Research

Table 3. U.S. Fuel Diversity in Megawatts

	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>
<u>Coal</u>	289,429	278,224	263,570	247,289	233,129
<u>Gas</u>	517,327	527,956	542,762	547,583	556,485
<u>Nuclear</u>	104,791	104,792	104,270	102,877	100,899
<u>Oil</u>	39,446	38,122	36,896	35,988	31,935
<u>Wind</u>	87,464	94,020	100,483	104,334	118,728
<u>Hydro</u>	101,020	101,238	101,786	101,661	101,865
<u>Other</u>	37,707	42,592	47,634	20,539	20,860
<u>Solar</u>	-	-	-	37,790	48,339

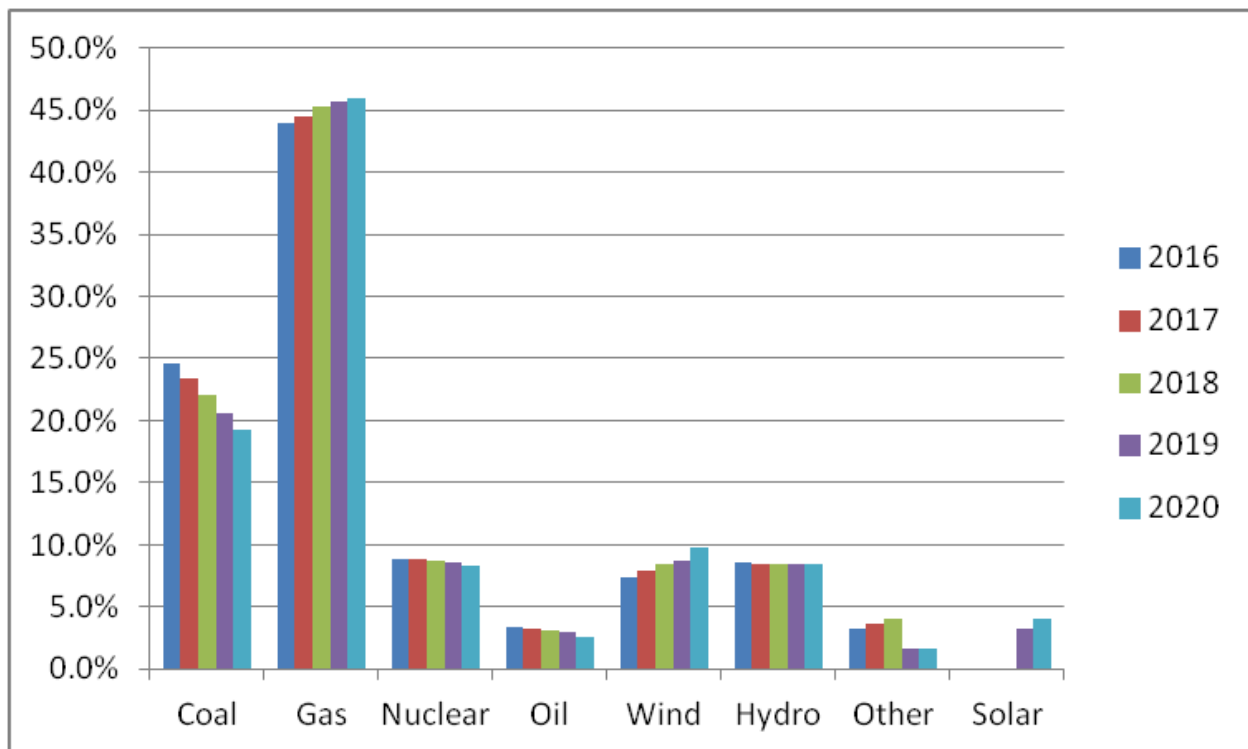
Source: Public Power Magazine

Table 4. U.S. Fuel Diversity by %

	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>
<u>Coal</u>	24.6%	23.4%	22.0%	20.6%	19.2%
<u>Gas</u>	43.9%	44.5%	45.3%	45.7%	45.9%
<u>Nuclear</u>	8.9%	8.8%	8.7%	8.6%	8.3%
<u>Oil</u>	3.4%	3.2%	3.1%	3.0%	2.6%
<u>Wind</u>	7.4%	7.9%	8.4%	8.7%	9.8%
<u>Hydro</u>	8.6%	8.5%	8.5%	8.5%	8.4%
<u>Other</u>	3.2%	3.6%	4.0%	1.7%	1.7%
<u>Solar</u>	-	-	-	3.2%	4.0%

Source: Public Power Magazine

Graph 2. U.S. Fuel Diversity by %



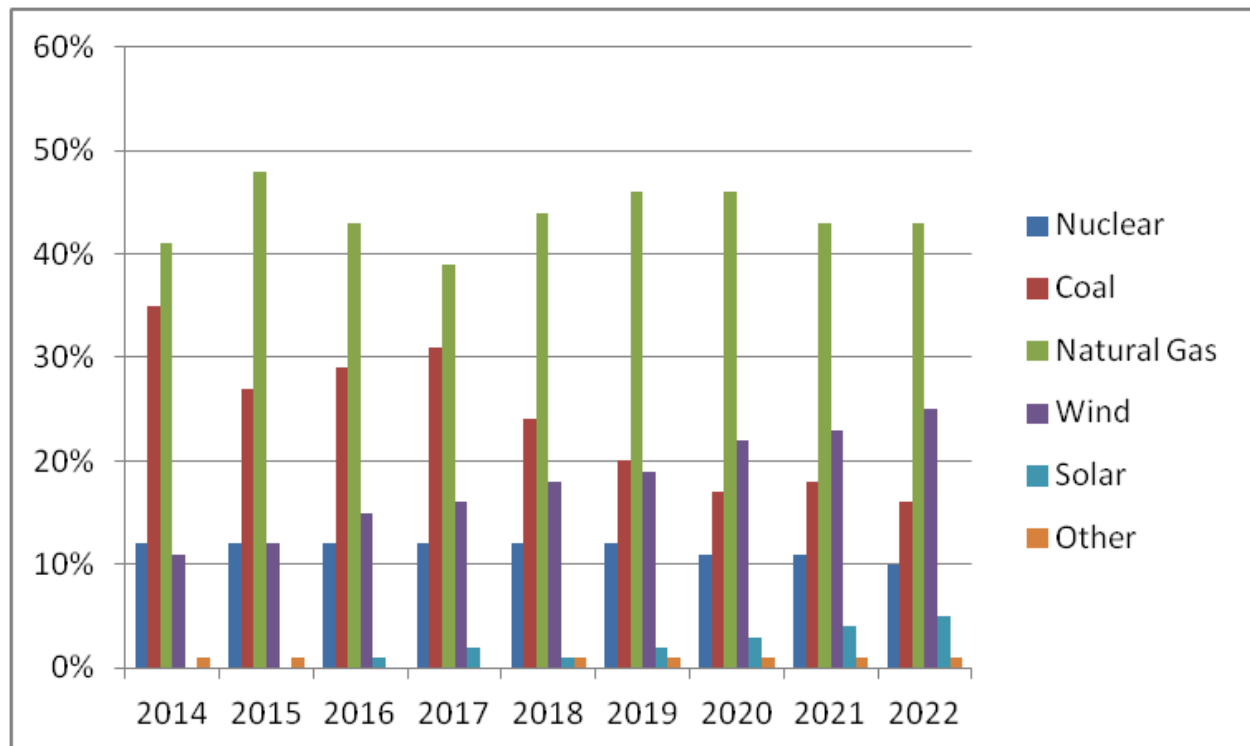
Source: Public Power Magazine

Table 5. Texas ERCOT Energy Generation Portfolio

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Nuclear	12%	12%	12%	12%	12%	12%	11%	11%	10%
Coal	35%	27%	29%	31%	24%	20%	17%	18%	16%
Natural Gas	41%	48%	43%	39%	44%	46%	46%	43%	43%
Wind	11%	12%	15%	16%	18%	19%	22%	23%	25%
Solar	0%	0%	1%	2%	1%	2%	3%	4%	5%
Other	1%	1%	0%	0%	1%	1%	1%	1%	1%

Source: Potomac Economics, 2022 State of the Market Report

Graph 3. Texas ERCOT Energy Generation Portfolio



Source: Potomac Economics, 2022 State of the Market Report

Table 6. Texas ERCOT Settlement Point Price by Fuel Type

	2020	2021	2022
Coal	\$24.84	\$148.06	\$70.00
Combined Cycle	\$24.60	\$207.84	\$80.71
Gas Peakers	\$60.26	\$1,023.09	\$189.86
Gas Steam	\$41.90	\$405.10	\$140.51
Hydro	\$23.88	\$305.15	\$87.76
Nuclear	\$20.31	\$137.71	\$60.78
Power Storage	\$80.50	\$109.29	\$92.64
Private Network	\$24.08	\$176.76	\$74.46
Renewable	\$35.23	\$43.54	\$83.00
Solar	\$25.49	\$75.97	\$73.09
Wind	\$11.45	\$60.53	\$34.09

Source: Potomac Economics, 2022 State of the Market Report

Table 7. Natural Gas Prices, NYISO

	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
<u>Tennessee Zn6</u>	\$3.26	\$2.13	\$4.68	\$9.20
<u>Iroquois Zn2</u>	\$3.04	\$2.09	\$4.36	\$8.82
<u>Transco Zn6</u>	\$2.59	\$1.64	\$3.49	\$7.04
<u>Tenn Z4 200L</u>	\$2.26	\$1.69	\$3.38	\$5.75

Source: Potomac Economics, 2022 State of the Market Report

Table 8. NYISO Energy Sources GWh

	<u>2020</u>	<u>2019</u>	<u>2018</u>	<u>2017</u>	<u>2016</u>
<u>RSolar</u>	48.5	52.1	48.8	47.3	53.7
<u>RWind</u>	4,161.90	4,453.60	3,985.10	4,219.20	3,943.30
<u>RSteam Turbine Refuse</u>	1,619.70	1832.3	1,878.40	1,900.10	1,840.90
<u>RSteam Turbine Wood</u>	0	154.6	203.4	288.3	292.5
<u>RInternal Combustion Methane</u>	612.9	660.9	647.6	730.1	747.7
<u>RConventional Hydro</u>	29,521.30	30,140.90	29,045.10	29,554.20	26,314.10
<u>NSteam BWR Nuclear</u>	22,236.70	23,099.60	21,962.50	22,215	21,448.80
<u>NSteam PWR Nuclear</u>	16,200.30	21,688.30	21,040.60	19,959.60	20,188.70
<u>PPumped Storage Hydro</u>	635.5	583.1	810.8	795.3	835.6
<u>FInternal Combustion Gas</u>	26.1	28.5	1.7	1.4	1.1
<u>FInternal Combustion Oil&Gas</u>	0.9	0.9	2	1.8	1.8
<u>FInternal Combustion Oil</u>	2.8	2.5	2.2	1.3	2.1
<u>FCombustion Turbine Gas</u>	737.7	541.9	732.9	671.3	905.3
<u>FCombustion Turbine Oil&Gas</u>	396.8	325.9	432.1	408.8	854.8
<u>FCombustion Turbine Oil</u>	82.8	26.2	36	18	45.8
<u>FJet Engine Gas</u>	88.1	118.9	140.8	99.6	211.9
<u>FJet Engine Oil&Gas</u>	451.4	741	916	728.7	1,284.10
<u>FJet Engine Oil</u>	112	71.1	89	36.2	70.6
<u>FCombined Cycle Gas</u>	8,556.70	5,580.40	5,465.10	4,887.40	5,555.10
<u>FCombined Cycle Oil&Gas</u>	37,235.70	36,894	37,099.60	35,355.60	39,017.10

<u>FSteam Turbine Coal</u>	145.9	425.6	692	567.4	1,492.80
<u>FSteam Turbine Gas</u>	1,120.90	1003.2	1,253.30	1,037.70	1,114
<u>FSteam Turbine Oil&Gas</u>	7,455.40	6,106.70	9,075.80	7,640.60	11,292.60
<u>FSteam Turbine Oil</u>	11.6	4.2	24.4	18.1	17.1
<u>Total</u>	131,461.6	134,536.3	135,585.2	131,182.9	137,531.5

Source: NYISO Gold Book, Load and Capacity Data Report

Table 9. NYISO Energy Sources GWh

	<u>2020</u>	<u>2019</u>	<u>2018</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<u>Gas</u>	10,530	7273	7594	6697	7787	9,737
<u>Oil</u>	209	104	152	74	136	146
<u>Gas and Oil</u>	45,540	44068	47526	44135	52450	52,028
<u>Coal</u>	146	425	692	567	1493	2,046
<u>Nuclear</u>	38,437	44788	43003	42175	41638	44,620
<u>Pumped Storage</u>	636	583	811	795	836	825
<u>Hydro</u>	29,521	30141	29045	29554	26314	25,879
<u>Wind</u>	4,162	4454	3985	4219	3943	3,984
<u>Solar</u>	49	52	49	47	54	52
<u>Other</u>	2,233	2648	2729	2919	2881	3,028
<u>Total</u>	131,462	134,536	135,585	131,183	137,532	142,345

Source: NYISO Gold Book, Load and Capacity Data Report

Table 10. NYISO Energy Sources %

	<u>2020</u>	<u>2019</u>	<u>2018</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>	<u>2014</u>
<u>Gas</u>	8%	5%	6%	5%	6%	7%	6%
<u>Oil</u>	1%	1%	1%	1%	1%	1%	1%
<u>Gas and Oil</u>	35%	33%	35%	34%	38%	37%	36%
<u>Coal</u>	1%	1%	1%	1%	1%	1%	3%
<u>Nuclear</u>	29%	33%	32%	32%	30%	31%	30%
<u>Pumped Storage</u>	1%	1%	1%	1%	1%	1%	1%
<u>Hydro</u>	22%	22%	21%	23%	19%	18%	18%
<u>Wind</u>	3%	3%	3%	3%	3%	3%	3%
<u>Solar</u>	1%	1%	1%	1%	1%	1%	1%
<u>Other</u>	2%	2%	2%	2%	2%	2%	2%

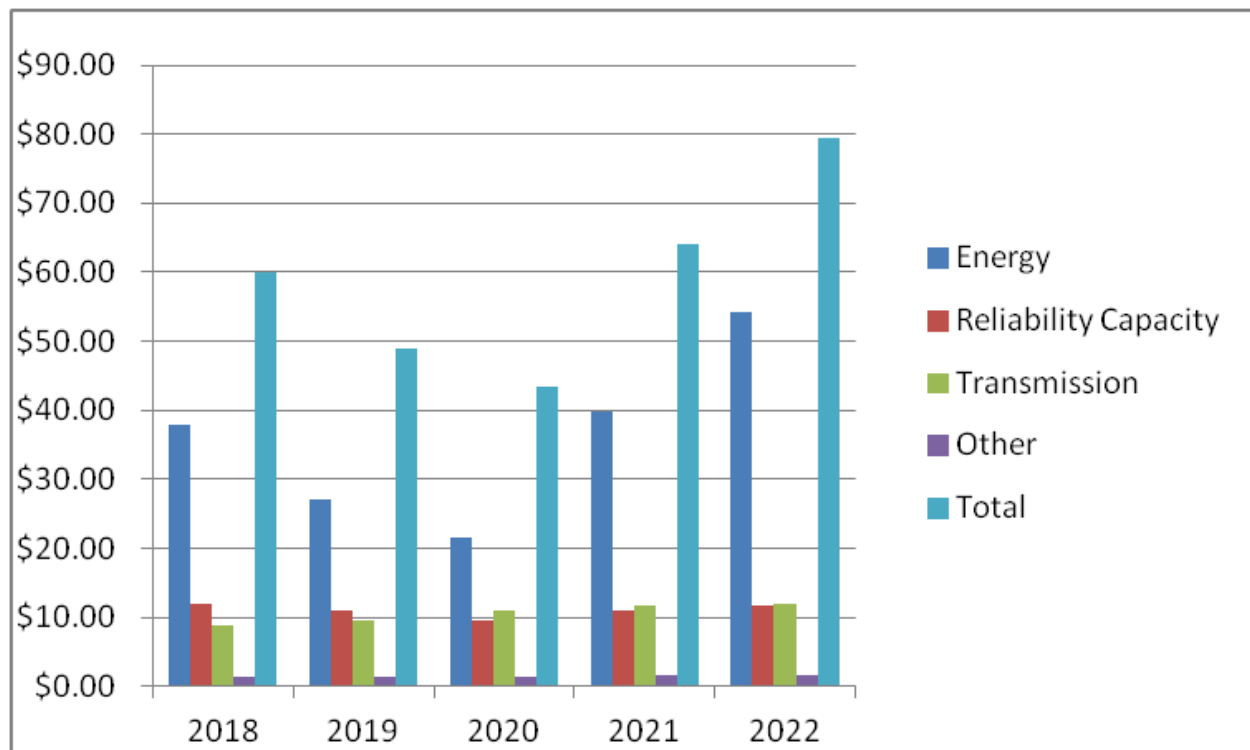
Source: NYISO Gold Book, Load and Capacity Data Report

Table 11. PJM Interconnection Wholesale Cost

	2018	2019	2020	2021	2022
Energy	\$37.83	\$27.15	\$21.65	\$39.79	\$54.16
Reliability Capacity	\$11.89	\$11.05	\$9.45	\$11.04	\$11.71
Transmission	\$8.84	\$9.52	\$11.03	\$11.72	\$11.98
Other	\$1.44	\$1.26	\$1.28	\$1.52	\$1.52
Total	\$60.00	\$48.98	\$43.41	\$64.07	\$79.37

Source: PJM Interconnection 2022 Markets Report

Graph 4. PJM Interconnection Wholesale Cost



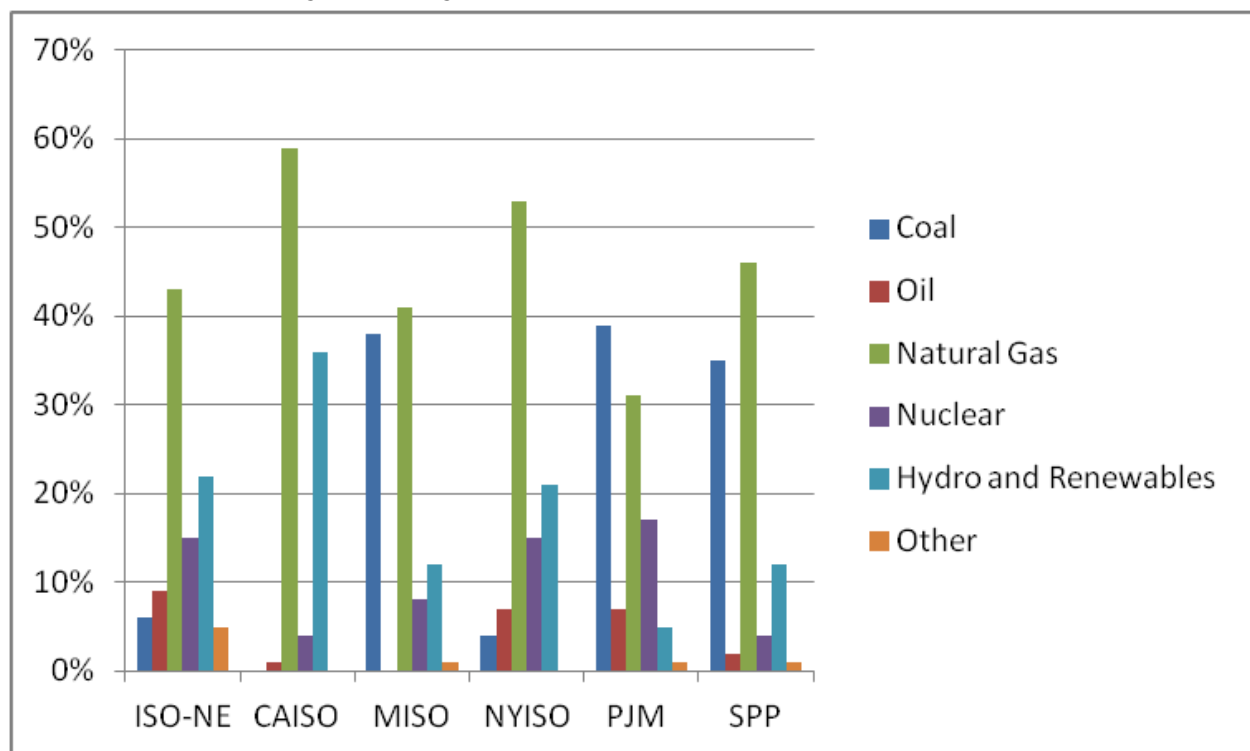
Source: PJM Interconnection 2022 Markets Report

Table 12. 2014 Fuel Diversity, Capacity Markets

	<u>ISO-NE</u>	<u>CAISO</u>	<u>MISO</u>	<u>NYISO</u>	<u>PJM</u>	<u>SPP</u>
<u>Coal</u>	6%	0%	38%	4%	39%	35%
<u>Oil</u>	9%	1%	0%	7%	7%	2%
<u>Natural Gas</u>	43%	59%	41%	53%	31%	46%
<u>Nuclear</u>	15%	4%	8%	15%	17%	4%
<u>Hydro and Renewables</u>	22%	36%	12%	21%	5%	12%
<u>Other</u>	5%	0%	1%	0%	1%	1%

Source: 2015 ISO/RTO Metrics Report

Graph 5. Fuel Diversity, Capacity Markets



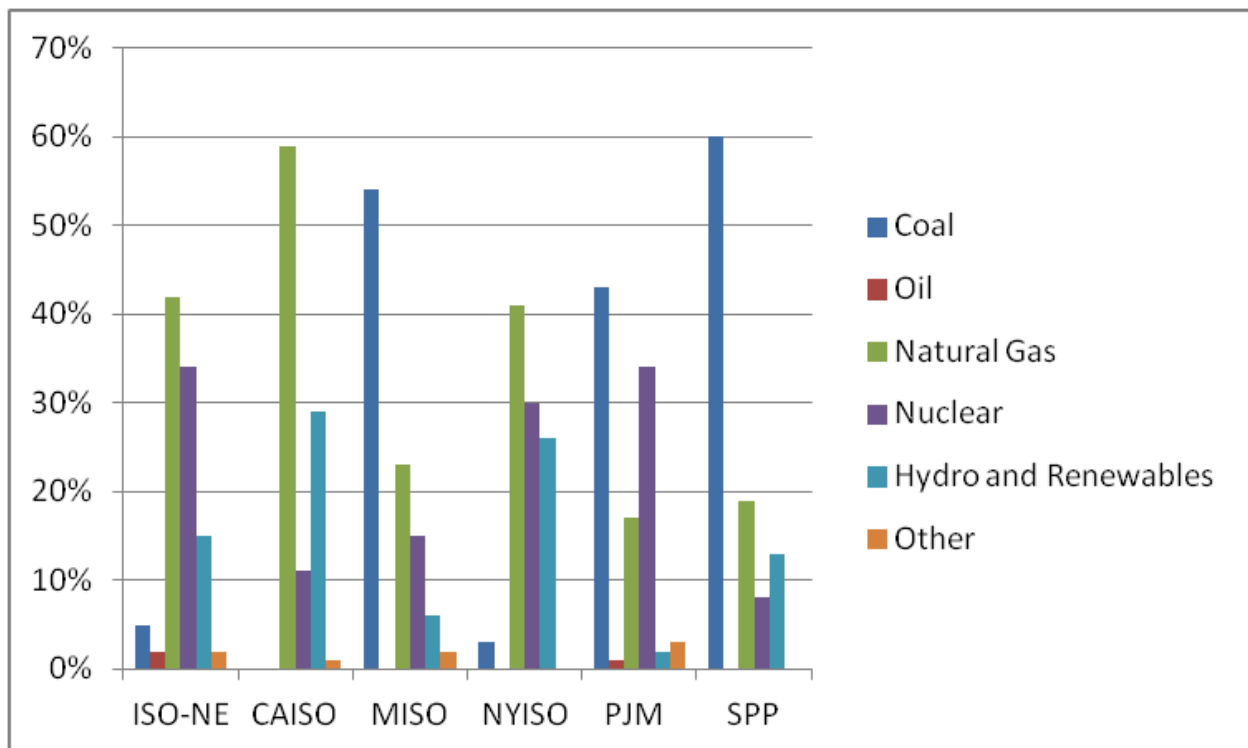
Source: 2015 ISO/RTO Metrics Report

Table 13. 2014 Fuel Diversity, Energy-Only Markets

	<u>ISO-NE</u>	<u>CAISO</u>	<u>MISO</u>	<u>NYISO</u>	<u>PJM</u>	<u>SPP</u>
<u>Coal</u>	5%	0%	54%	3%	43%	60%
<u>Oil</u>	2%	0%	0%	0%	1%	0%
<u>Natural Gas</u>	42%	59%	23%	41%	17%	19%
<u>Nuclear</u>	34%	11%	15%	30%	34%	8%
<u>Hydro and Renewables</u>	15%	29%	6%	26%	2%	13%
<u>Other</u>	2%	1%	2%	0%	3%	0%

Source: 2015 ISO/RTO Metrics Report

Graph 6. Fuel Diversity, Energy-Only Markets



Source: 2015 ISO/RTO Metrics Report

Table 14: ISO-NE Capacity Auction Results

Auction Number	Demand in Megawatts			Supply (MW)			Reserve Margin	
	Capacity	Expected	Region-wide	Capacity	Capacity	Total	Calculated	Calculated
	Delivery	Peak	Resource	Commitments	Commitments	Capacity	with	with Total
	Year	Demand	Adequacy	Procured in	Procured	Commitments	Resource	Capacity
			Requirement	Capacity	Outside the	Procured	Adequacy	Commitments
				Auctions	Capacity		Requirement	Procured
					Auction			
1	2010/2011	29,035	31,480	32,085	1,308	33,392	8	15
2	2011/2012	29,405	31,232	34,971	851	35,822	6	22
3	2012/2013	29,020	30,709	34,582	854	35,436	6	22
4	2013/2014	28,570	30,862	35,108	856	35,964	8	26
5	2014/2015	29,025	31,900	34,595	891	35,486	10	22
6	2015/2016	29,380	32,221	33,928	973	34,902	10	19
7	2016/2017	29,400	31,777	33,829	985	34,815	8	18
8	2017/2018	29,790	32,618	31,478	998	32,475	9	9
9	2018/2019	30,005	32,823	32,405	890	33,295	9	11
10	2019/2020	29,861	32,808	33,220	911	34,130	10	14
11	2020/2021	29,601	32,722	33,470	896	34,366	11	16

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in ISO New England's initial capacity auction for capacity delivery years 2010/2011 through 2020/2021.

Table 15: MID ISO Capacity Auction Results

Auction Number	Capacity Delivery Year	Demand in Megawatts (MW)				Supply (MW)	Reserve Margin (percent)	
		Expected	Region-wide	Capacity	Capacity	Total	Calculated	Calculated
		Peak	Resource	Commitments	Commitments	Capacity	with	with Total
		Demand	Adequacy	Procured in	Procured	Commitments	Resource	Capacity
			Requirement	Capacity	Outside the	Procured	Adequacy	Commitments
				Auctions	Capacity		Requirement	Procured
					Auction			
1	2013/2014	91,539	97,214	62,255	34,959	97,214	6	6
2	2014/2015	127,597	136,912	89,890	47,022	136,912	7	7
3	2015/2016	127,319	136,359	88,130	48,229	136,359	7	7
4	2016/2017	125,913	135,483	99,488	35,995	135,483	8	8
5	2017/2018	125,003	134,753	85,290	49,463	134,753	8	8

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in Midcontinent ISO's initial capacity auction for capacity delivery years 2013/2014 through 2017/2018.

Table 16: NYISO Capacity Auction Results

	Demand in Megawatts		Supply (MW)	Reserve Margins	
	(MW)			(percent)	
Capacity	Expected Peak	Region-wide	Total Capacity	Calculated with	Calculated with Total
Delivery	Demand	Resource	Commitments	Resource	Capacity
Month		Adequacy	Procured	Adequacy	Commitments
		Requirement	In and Outside the	Requirement	Procured
			Auctions		
Aug-06	33,295	37,154	39,829	12	20
Aug-07	33,447	37,228	39,691	11	19
Aug-08	33,809	36,633	39,663	8	17
Aug-09	33,930	36,362	39,219	7	16
Aug-10	33,025	35,045	38,609	6	17
Aug-11	32,712	34,684	38,827	6	19
Aug-12	33,295	35,076	38,477	5	16
Aug-13	33,279	35,467	37,338	7	12
Aug-14	33,666	35,812	37,547	6	12
Aug-15	33,567	35,920	38,665	7	15
Aug-16	33,359	35,430	38,166	6	14

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in NYISO's initial capacity auction for the capacity delivery month of August for 2006 through 2016.

Table 17: PJM Capacity Auction Results

Auction	Capacity	Expected	Region-wide	Capacity	Capacity	Total	Calculated	Calculated
Number	Delivery	Peak	Resource	Commitments	Commitments	Capacity	with	with Total
	Year	Demand	Adequacy	Procured in	Procured	Commitments	Resource	Capacity
			Requirement	Capacity	Outside the	Procured	Adequacy	Commitments
				Auctions	Capacity		Requirement	Procured
					Auction			
1	2007/2008	137,421	148,277	129,409	24,133	153,542	8	12
2	2008/2009	139,806	150,935	129,598	24,404	154,001	8	10
3	2009/2010	142,177	153,480	132,232	24,694	156,926	8	10
4	2010/2011	144,592	156,637	132,190	25,596	157,786	8	9
5	2011/2012	142,390	154,251	132,222	25,186	157,408	8	11
6	2012/2013	144,857	157,489	136,144	23,756	159,900	9	10
7	2013/2014	160,634	173,549	152,743	23,560	176,304	8	10
8	2014/2015	164,758	178,087	149,975	29,763	179,738	8	9
9	2015/2016	163,168	177,184	164,561	14,407	178,968	9	10
10	2016/2017	165,412	180,332	169,160	14,205	183,364	9	11
11	2017/2018	164,479	179,545	167,004	14,538	181,542	9	10
12	2018/2019	161,418	174,897	166,837	14,289	181,126	8	12
13	2019/2020	157,189	171,037	167,306	13,944	181,250	9	15
14	2020/2021	153,915	167,644	165,109	13,289	178,398	9	16

Source: GAO-18-131, Electricity Markets. Demand, supply, and reserve margins in PJM Interconnection's initial capacity auction for capacity delivery year 2007/2008 through 2020/2021.

Table 18: 4 RTOs with Capacity Markets

RTO	Year	Energy Market	Capacity	Ancillary	Total RTO Market	Total RTO Market
		Costs	Market	Services	Costs	Costs
			Costs	Market Costs		(in dollars per megawatt-hour)
ISO New England	2011	7,223	1,451	42	8,715	64
	2012	5,500	1,252	60	6,812	51
	2013	8,349	1,083	158	9,590	71
	2014	9,297	1,081	339	10,717	82
	2015	5,988	1,124	212	7,325	56
	2016	4,130	1,160	146	5,437	42
Midcontinent ISO	2014	27,433	320	54	27,808	42
	2015	18,086	536	42	18,664	29
	2016	17,680	1,120	53	18,853	29
New York ISO	2009	7,916	1,463	173	9,551	60
	2010	9,875	1,714	176	11,764	72
	2011	8,937	848	147	9,932	61
	2012	6,894	1,583	134	8,611	53
	2013	8,941	2,965	152	12,057	74
	2014	9,611	3,403	147	13,161	82
	2015	6,298	2,595	139	9,033	56
	2016	4,834	2,039	191	7,065	44

PJM Interconnection	2008	60,658	7,638	921	69,218	91
	2009	30,872	9,808	669	41,349	58
	2010	39,637	10,680	705	51,021	68
	2011	38,511	8,198	734	47,443	61
	2012	30,612	5,508	646	36,766	45
	2013	33,670	6,463	1,147	41,280	49
	2014	45,569	7,987	911	54,467	65
	2015	30,194	9,727	648	40,569	49
	2016	24,300	9,400	570	34,270	41

Source: GAO-18-131, Electricity Markets. Total annual costs in regional transmission organizations (RTO) with capacity markets, in millions of dollars, adjusted for inflation, for available years.

Table 19: 6 RTOs, Wholesale Power Costs by Charge Type

RTO/ISO	2014	2015	2016	2017	2018
CAISO					
Energy	\$50.83	\$34.61	\$30.84	\$38.09	\$46.46
Transmission	\$8.03	\$9.87	\$10.82	\$9.85	\$11.91
Capacity	-	-	-	-	-
Operating Reserves	\$0.30	\$0.27	\$0.51	\$0.69	\$0.85
Ancillary	\$0.00	\$0.00	\$0.00	-	-
RTO and Regulatory Fee	\$0.40	\$0.42	\$0.42	\$0.42	\$0.43
Other	\$0.54	\$0.50	\$0.40	\$0.52	\$1.41
ISONE					
Energy	\$51.87	\$30.94	\$35.43	\$45.76	\$42.23
Transmission	\$14.18	\$15.95	\$16.78	\$18.11	\$17.87
Capacity	\$8.56	\$9.17	\$9.40	\$25.07	\$32.49
Operating Reserves	\$1.87	\$0.75	\$0.80	\$0.86	\$0.82
Ancillary	\$0.32	\$0.32	\$0.30	\$0.29	\$0.31
RTO and Regulatory Fee	\$1.30	\$1.37	\$1.50	\$1.58	\$1.57
Other	\$0.43	\$0.45	\$0.45	\$0.34	\$0.12
MISO					
Energy	\$36.91	\$25.02	\$24.34	\$26.70	\$29.15
Transmission	\$2.65	\$2.93	\$3.45	\$3.74	\$3.55
Capacity	\$0.00	\$0.00	\$0.01	\$0.00	\$0.00
Operating Reserves	\$0.08	\$0.06	\$0.08	\$0.10	\$0.11
Ancillary	\$0.30	\$0.33	\$0.35	\$0.34	\$0.35
RTO and Regulatory Fee	\$0.20	\$0.21	\$0.21	\$0.24	\$0.32

Other	\$0.56	\$0.26	\$0.25	\$0.32	\$0.32
NYISO					
Energy	\$33.92	\$22.48	\$18.31	\$19.05	\$25.19
Transmission	\$0.66	\$0.64	\$0.83	\$0.79	\$0.85
Capacity	-	-	-	-	-
Operating Reserves	\$0.58	\$0.50	\$0.85	\$0.76	\$0.81
Ancillary	\$0.44	\$0.46	\$0.45	\$0.47	\$0.55
RTO and Regulatory Fee	\$0.71	\$0.72	\$0.91	\$0.98	\$0.96
Other	\$0.14	\$0.07	\$0.15	\$0.28	\$0.20
PJM					
Energy	\$53.14	\$36.16	\$29.23	\$30.99	\$38.24
Transmission	\$5.72	\$6.90	\$7.12	\$8.62	\$8.57
Capacity	\$8.91	\$11.14	\$8.99	\$8.75	\$11.89
Operating Reserves	\$0.59	\$0.36	\$0.24	\$0.24	\$0.31
Ancillary	\$0.51	\$0.51	\$0.53	\$0.59	\$0.57
RTO and Regulatory Fee	\$0.26	\$0.27	\$0.21	\$0.32	\$0.32
Other	\$1.15	\$0.38	\$0.16	\$0.11	\$0.21
SPP					
Energy	\$3.47	\$2.59	\$4.02	\$4.29	\$4.24
Transmission	\$5.68	\$6.34	\$7.49	\$8.16	\$8.05
Capacity	-	-	-	-	-
Operating Reserves	\$0.39	\$0.27	\$0.28	\$0.29	\$0.29
Ancillary	\$0.15	\$0.17	\$0.21	\$0.22	\$0.21
RTO and Regulatory Fee	\$0.63	\$0.69	\$0.61	\$0.69	\$0.67
Other	\$0.43	\$0.33	\$0.35	\$0.33	\$0.36

Source: GAO-18-131, Electricity Markets.

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