STATEMENT OF THE ELECTRIC POWER SUPPLY ASSOCIATION

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Thank you for inviting the Electric Power Supply Association ("EPSA") to participate on the opening panel of today's first stakeholder meeting on the second installment of the Quadrennial Energy Review ("QER 1.2"). The Administration and Congress are wise to be focusing intently in this second installment on a top to bottom, across-the-board detailed review of electricity to make sure the changing and growing pieces of our electric systems continue to fit together at a time of rapid changes. Accordingly, it is appropriate that the topic for this first panel is "Bulk Power Generation and Transmission: How Can We Plan, Build, and Operate the Appropriate Amount for Future Needs?"

While the temporal scope of QER 1.2 is out to the year 2040, it is *critical* that Congress, the Administration, federal agencies such as the Federal Energy Regulatory Commission ("FERC"), and States work with each other and all stakeholders *now* on issues that require immediate attention over the next few months, years and the coming decade. Getting policies and programs right in 2016 will make it far more likely that the period between now and 2040 is one in which the many exciting transformations already underway in electricity reach their greatest potential with a minimum of peril. EPSA appreciates the intensive QER stakeholder engagement. This QER 1.2 undertaking allows all of us to look at the bigger picture and should require each of us to come together as pragmatic problem-solvers, not merely as rent-seekers.

EPSA is the national trade association for leading competitive wholesale power suppliers. EPSA members are independent power producers and competitive generation affiliates of utility holding companies that in the aggregate represent well over 200,000 megawatts of power supply capacity essential to resource adequacy and reliability. EPSA members individually and collectively are fuel diverse and among the largest operators of each fuel type: over half of member assets are natural gas-fired, including dual-fuel units; one-fifth is nuclear power; over one-sixth is coal; and the balance is renewable (wind, solar, geothermal and hydro). While EPSA's mission relates to wholesale markets, EPSA members are also among the largest suppliers of innovative customer-facing solutions fostered by vibrant retail electricity markets.

Over 95 percent of EPSA member assets are in the existing "organized markets" administered by Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"). RTOs/ISOs of various types now cover almost 75 percent of the country and its economic output. RTOs/ISOs continue to expand as they have in recent years, including in the West where doing so outside California was once virtually unthinkable. EPSA members and other competitive suppliers also have assets outside the RTOs/ISOs, but over time have shifted their investments largely to the RTOs/ISOs because of continuing artificial barriers to entry in those remaining parts of the country that lack RTOs/ISOs as a regional platform for the innovation and efficiencies that are facilitated by independent operation of the grid. The broader wholesale competitive power sector accounts for over 40 percent of the U.S. installed generating capacity, which represents all or nearly all of the supply in many states and regions.

Prologue: History of Competitive Wholesale Power Markets

Before the QER 1.2 process can help determine the best policy paths forward to 2040, it is important to start with the baseline of the experience that has preceded us, lest, to borrow the well-worn phrase, we are condemned to repeat past mistakes.

As a refresher for those not around for the past pitched battles that largely brought us to the present day, the nation was dependent on vertically-integrated utilities with defined exclusive service territories prior to when wholesale and retail competition started to take root in the 1990s.[1] These utilities, many of which still exist today, generate electricity at central station power plants they own, move the power over their own high-voltage transmission lines to load within their service territories, and operate the local distribution wires over which that electricity reaches consumers. As franchised monopolies, these utilities are subject to cost-of-service rate regulation. Regulators set rates such that, at least in theory, these monopoly utilities are only allowed to recover prudently incurred costs and a rate of return based on their capital structure. As outlined below, while several regions remain dependent on such utilities, that is no longer the case in most of the country. For present purposes it is important to point out that even in regions without statutory "retail choice" and access to cheaper wholesale power alternatives, new technologies are empowering consumers as never before.

Serious concerns about how vertically-integrated utilities operated began to emerge in the 1970s and 1980s with vigorous debates in Congress and before state legislatures. Lack of competition and the cost-based nature of traditional regulation

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[1] For a history of wholesale and retail competition, see Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (pursuant to Section 1815 of the Energy Policy Act of 2005), prepared by an interagency task force led by the Department of Energy, available at http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf

meant that utilities were rewarded for higher costs, not lower ones. Multi-billion dollar cost overruns and construction delays were increasingly common with attendant costs passed on to captive ratepayers. Vertically-integrated utilities, often with relatively small geographic footprints, meant that each utility built more and more plants to service its exclusive territories. This was rightfully seen as highly inefficient and ultimately costly for consumers. (Sadly, history is repeating itself again today with several multi-billion-dollar cost-of-service, rate-based projects under way that are following the well-worn path of cost overruns, delays and higher consumer costs.) Utilities controlled transmission lines which allowed them to block access to or through their systems by competitors. At the same time, greater reliance on market forces was largely working in transportation and telecommunications sectors, delivering dividends for decades.

Congress took the first steps toward competition at wholesale through the Public Utility Regulatory Policies Act of 1978 ("PURPA") that among other provisions required utilities to purchase power from certain renewable and small power plants known in the PURPA vernacular as "qualifying facilities" ("QFs"). While the implementation of PURPA had its imperfections, the law proved that power generation is not a natural monopoly requiring the same entity to control generation, transmission and distribution through the award of the exclusive right to operate in a defined customer territory. Congress on a bipartisan basis added provisions to the Energy Policy Act of 1992 that directed FERC to allow greater non-discriminatory access to the transmission system for power producers other than the vertically-integrated utilities. The 1992 law also created "exempt wholesale generators" to allow independent power producers to pursue larger scale projects than those allowed by PURPA.

FERC implemented EPACT92 through a series of landmark bipartisan orders. These orders imposed open access requirements on transmission owners so that new entrants independent of the vertically-integrated utility could get their power to customers choosing to purchase it. FERC also promoted the voluntary formation of RTOs to operate the grid independently of the owners of the transmission lines. RTOs began to run wholesale markets through which power plants are dispatched on a least cost basis using security-constrained economic dispatch (SCED). In such markets, power plants - whether in a single state ISO (California, New York and Texas) or in a multi-state RTO (ISO New England, PJM Interconnection, Midcontinent ISO, and Southwest Power Pool) – are dispatched regardless of who owns them so that consumers receive the benefit of the least cost mix of supply resources to meet demand for electricity at any given time. Some states restructured their retail electricity systems, including by unbundling power generation from traditional cost-of-service rate-regulation, and allowing entities other than vertically-integrated utilities to sell power at retail.

The combination of greater wholesale and retail competition fundamentally altered the economics in a way better suited to consumers. Instead of cost-plus rates paid by captive customers, suppliers within RTO "organized markets" had to earn revenues through sales in competition with others. No longer would simply spending more mean making more profits. Predictably, with economic incentives better aligned, competitive producers took over existing power plants, getting more out of them: capacity factors increased considerably, refueling times at nuclear plants shortened dramatically, and the fuel efficiency of coal plants increased substantially.

At the same time, new entrants came into the business with new technologies and resource types such as wind, solar and combined-cycle natural gas plants. It is undeniable that but for the courageous leadership of key policymakers in the 1990s (in Congress, the Department of Energy, and at FERC), and the risk-taking, competitive power sector entrepreneurs that then made the policy vision a marketplace reality through their own investments, the country would not be standing on the platform that exists today to usher in the next wave of cleaner, more reliable, and flexible sources of electricity that are the focus of QER 1.2. Then as now the lesson remains the same: Investment decisions as to existing and new electricity resources are best made, as they are generally in a market-economy such as ours, through well-functioning markets that place much greater risks on, and commensurately reward, developers, owners, operators, and investors better able to manage those risks, as opposed to shoving those risks and their associated costs on captive customers with little or no choice but to pay up for mistakes and miscalculations made by others in their name.

Wholesale Bulk Power Markets Today: Rapid Change Is the New Constant

As described above, wholesale competitive power markets have been decades in the making and continue to evolve while providing a range of demonstrable and quantifiable benefits to consumers, the environment and the economy. For this to continue, all business models and their regulatory paradigms – whether cost-of-service regulation of vertically-integrated utilities or market design, tariffs and operator practices in RTO/ISO markets – must rapidly improve to keep pace with the changes occurring due to technological, economic and policy developments that could upend the status quo.

Potentially disruptive technologies are poised to deliver substantial benefits for customer choice, decarbonization of the power sector, economic efficiency and growth, and greater resiliency. However, these changes will not happen overnight. A major challenge to this growing sector of the electric industry is how to ensure that different policymakers – at the federal and state levels – allow these resources to compete against regulated monopolies that continue to exist at the distribution level. Regulatory models should welcome new entrants and ways of doing things, while recognizing that for years to come the bulk power system will need to accommodate both central station power plants and greater distributed resources (on and off the grid) to maintain reliability. The bulk power system is physically and financially interconnected in deeply entwined ways not present in other sectors of the economy where the "Internet of things" and the "shared economy" have taken greater root. No Supreme Court decision, act of Congress, or Executive Order can repeal the laws of physics and fundamental economic principles. Competition at all levels of the grid helps contain consumer costs.

The QER 1.2 stakeholder briefing documents accurately capture the changing electricity landscape: natural gas production growth of higher volumes at lower prices; increased intermittent renewables from lower costs, state mandates, and tax credits; increased production and end-use efficiency; increased interdependencies, such as those between the electric and natural gas sectors; and heightened awareness of cyber and physical security, among others. Likewise, the detailed list of 14 issues that QER 1.2 is expected to address are extensive. While all of them are important, particular attention should be paid to electricity markets, electricity finance, electricity valuation, and jurisdiction/regulations.

EPSA has always stressed from both resource adequacy and operational perspectives that reliability requires ample supplies of affordable and environmentally responsible electricity. This requires generation from a network of plants operating simultaneously with base load, mid-merit and peaking capabilities deploying a range of fuels and technologies because electricity demand fluctuates hourly and seasonally. EPSA's preferred approach is to refine market-based mechanisms and solutions that to the maximum extent possible are fuel neutral. This means defining attributes and letting those who can provide them compete in well-functioning wholesale markets. That is easier said than done given numerous, on-going federal and state policy debates, the outcome of which could undermine the ability of wholesale power markets to perform reliably and efficiently. The most cost effective solution is to allow existing resources to compete with newer technologies on a level playing field.

The power sector is in the early stages of what will likely be a multi-year, even multi-decade, series of profound changes to how electricity is generated and consumed. For starters, the correlation between economic growth and demand for electricity has weakened so volumetric-based revenues weaken as well. While evolutionary in apparent pace at the moment, the end result could be revolutionary compared to the system today. The one-directional power flows exclusively from central station power plants to consumers are shifting to greater multi-directional power flows with enhanced consumer tools to better manage consumption. As intermittent resources such as wind and solar increase, other power plants are required to operate differently than designed, with greater wear and tear on those plants. Resources that can ramp up and down rapidly become central to reliability when electricity from intermittent resources declines.

As the cost of renewables continues to come closer to those of conventional resources, as supplies of relatively low-cost natural gas appear plentiful for decades, as new technologies such as distributed generation and battery storage emerge, and as the relative economics of conventional fuels changes, traditional "integrated resource planning" falls victim to the conceit of perfect knowledge that is elusive when change is accelerating rapidly and will if anything quicken in pace in the future. As a result, well-designed and properly regulated competitive wholesale markets remain the best model to manage these challenges and risks because markets are inherently more flexible, adaptable and place more risks on investors than consumers. Any market depends on ample opportunities, not guarantees, for suppliers to receive market revenues sufficient to recover costs and thus *earn* a fair risk-adjusted return of and on invested capital.

<u>The Critical Importance of Making Electric Energy Pricing Improvements Soon</u>

EPSA is pleased to have joined the Edison Electric Institute, Nuclear Energy Institute, Natural Gas Supply Association and America's Natural Gas Alliance in stressing the importance of electric energy price formation reforms now underway at FERC.[2] QER 1.2 can assist in making those near-term proposed reforms a reality, while also looking farther down the road at even more fundamental changes to the economic regulation of the bulk power system that will likely be needed as the resource mix and the proportion of bulk power and non-bulk power supplies and demand-side management shifts over time.

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[2] *Price Formation in Energy and Ancillary Services Markets Operated by [RTOs] and [ISOs]*, Docket No. AD14-14-000, Letter on Joint Price Formation Principles from EPSA, EEI, NEI, NGSA and ANGA, (submitted March 9, 2015), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13797119.

From the outset, it is important to differentiate three types of markets that ISOs/RTOs administer: (1) sales of electric energy when power plants are dispatched, (2) sales of ancillary services (such as voltage support and frequency response), and (3) capacity markets where they exist (in many but not all RTOs/ISOs) to help recover fixed power plant costs. "Energy price formation" refers to a basket of issues that go to how RTOs/ISOs determine the granular Locational Marginal Prices ("LMPs") at thousands of nodes in the Day Ahead and Real Time markets for sales of electric energy. For most plants (all but peaking units) energy sales are the primary source of revenues. LMPs and associated revenues are tightly bounded by FERC-approved market designs and tariff rules along with RTO/ISO grid operator actions.

Everyone – consumer and supplier alike – should want bulk power system energy price formation improvements this year. Markets for any good or service, not just electricity, require prices that accurately reflect supply, demand and system conditions. This is true regardless of whether generation is base load, peaking, or in between; whether the fuel is coal, natural gas, nuclear or renewables; and whether from central station plants or distributed resources. Absent accurate prices, RTO/ISO energy markets will send distorted information about when, where and how to invest (or not) to meet future needs. While always important, this is critical today given long-lead times and multi-decade projects at a time of considerable change in the electric sector's needs and resource mix.

Electricity has unique characteristics that make it a challenge to arrive at prices truly reflective of the total costs of providing reliable service on the bulk power system. The physics of electricity are such that generation from dozens to hundreds of power plants is needed simultaneously to meet demand in any instant. Electricity production from multiple plants is essentially co-mingled to supply consumers, not delivered in physically separate packages. Electricity supply is required to be in surplus through necessary mandatory reserve margins, not in the equilibrium of economics text books. Electricity supply and demand are thus more interconnected physically and financially than is the case for other goods and services in the economy.

In RTO/ISO markets, grid operators independent of generators determine the dispatch of specific power plants. This is done under detailed FERC-approved tariff rules including limits on what costs can be included in supplier bids, which units can set the single market-clearing price paid to all resources, and an outdated artificial cap on supply offers even when costs exceed the cap, as happened during the Polar Vortex of 2014. Thus, power producers do not unilaterally determine the prices they can bid into RTO/ISO markets, much less set the prices they receive. This produces competitive pricing outcomes as documented by periodic data-driven analytical reports and "state of the market" assessments from RTO/ISO market monitors as well as from FERC and others. RTOs/ISOs and their market monitors should be engaged on QER 1.2

Various power plants have widely differing operating characteristics including as to how long it takes for the unit to come online, how long it needs to stay online, and at what minimum and maximum output. Grid operators dispatch plants not only on the basis of pure economics, but constantly take different plant operating characteristics and their expectations of changes to near term demand levels into account. In short, largely for good reason, grid operators make dispatch decisions "conservatively" so as not to run even the slightest risk of coming up short of power.

When the grid operator takes out of market actions the effect is to call on certain plants to be dispatched out of merit order and others to stand by in reserve or not run at all even if otherwise they would run on a purely least cost basis. Generally, units called out of order are not allowed to set the market price for the remaining units even though the effect of calling on them is to reduce prices and volumes for the rest. Instead, the out of merit units are paid separately through "uplift" to cover their costs. The "uplift" is ultimately allocated to consumers. This is not hedgeable, meaning it is a risk for consumers that cannot be protected against in advance through financial arrangements as can be done to manage energy price risk. "Uplift" reached very high record levels in the winter of early 2014, and while 2015 winter levels were lower than 2014 they were still high by historical measures. Such levels of "uplift" – like elevated body temperature – are a sign of potentially unhealthy conditions. While "uplift" will never be eliminated, nor should it be, most wholesale power market experts agree it should be kept to a minimum.

While operator actions and "uplift" have existed for a long time, it was not material to energy price formation until the advent of plentiful relatively low-cost natural gas and weaker power demand artificially exerted structurally downward pressure on wholesale prices, which as shown in multi-year RTO/ISO data have been much lower in recent years than earlier ones, sometimes less than half historic peaks. The latest EIA data calculated that wholesale power prices are at historic lows and dropped dramatically year over year from 2014 to 2015.[3] EIA data also shows that power prices

[3] See, "Wholesale power prices decrease across the country in 2015," *Today in Energy*, U.S. Energy Information Administration (January 11, 2016) ("Wholesale electricity prices at major trading hubs on a monthly average basis for on-peak hours were down 27%-37% across the nation in 2015 compared with 2014, driven largely by natural gas prices.") Available at www.eia.gov/todayinenergy.

have predictably and generally followed the trend lines of natural gas prices, as natural gas tends to be, although is not always, the marginal fuel setting power market prices. This correlation demonstrates conclusively that those who in the past criticized the concept of markets and existing power market rules for higher power prices when natural gas input costs were much higher than today were off base in their criticism.

Understandably, one might conclude that today's deflationary wholesale prices are a boon for consumers, but on further inspection it is at best temporary as the present situation is not sustainable for certain power plants and the long-term overall health of wholesale markets. The reason is that no business asset can survive for long if it cannot recover its costs plus an adequate risk-adjusted return of and on invested capital. In addition, depending on a given state's regulatory mechanisms and decisions about non-generation components of retail rates (transmission and distribution), retail rates may be flat to actually increasing despite the historic drop in wholesale prices.

In any market, over time some assets will retire and new assets will enter. When that happens on the basis of true economic merit, it is markets at work. Here, however, the substantial risk is that consumer costs will actually increase over time if more power plants continue to retire prematurely (e.g., recent nuclear plant retirement announcements) and other power plants with operational attributes required by the changing resource mix (e.g., natural gas plants that can ramp up and down quickly to adjust to rising and falling intermittent resource) are not properly compensated. The replacement cost of new plants can be substantially higher than what some existing resources facing closure would have needed to stay in operation, depending on the specific circumstances in a given market.

RTOs/ISOs generally work well and provide meaningful benefits to consumers, the economy and the environment, which is why their geographic scope has expanded. However, any market can and should be improved as lessons are learned. Including bulk power electric energy price formation reforms in QER 1.2 will raise timely awareness of how RTOs/ISOs need to adapt quickly to changing dynamics that impact investment decisions as to existing and new supply resources. Importantly, these regulatory reforms will help address the concerns raised in Congress and by others about base load generation, renewable resources, and capacity markets.

FERC has spent a great deal of time on important issues around capacity markets as they were introduced in certain RTOs/ISOs. Until recently, FERC spent far less time on the larger bulk power electric energy markets. To its credit, FERC has accomplished a great deal since 2013 looking into how prices are formed in these markets. FERC held three day-long technical conferences preceded by issuance of detailed staff reports from September through December 2014. Earlier last year, FERC posed a series of thoughtful questions for public comment on which numerous submissions from various points of view were made. Later last year, FERC issued proposals on electric energy market offer flexibility, pricing intervals, and scarcity pricing. FERC also required each RTO/ISO to report back to the Commission on a range of other issues by March 4, 2016. At its first meeting of 2016 in January, FERC issued for comment a proposal to address outdated and counter-productive electric energy bid caps. FERC's dockets now offer a compelling record that improvements to determining Day Ahead and Real Time energy prices are urgently required. QER 1.2 should use that FERC record as a foundation in this area.

EPSA's recommended reform priorities focus on improved market pricing through steps to price dispatch decisions made by grid operators in the name of reliability more frequently in the market prices for all to see and less so through opaque out-of-market "uplift" payments; greater transparency around grid operator actions; lifting or changes to energy offer caps; sub-hourly pricing to better compensate plants capable of ramping quickly; and intra-day offer flexibility so that supplier bids to RTOs/ISOs better reflect market conditions such as fuel costs. [4] The much less desirable alternative, which is likely in the absence of action in the next few months, is further Balkanization of the power sector by fuel type and plant location. This would be accompanied by more requests for out-of-market payment mechanisms, eroding rather than reinforcing the competitive markets that Congress and FERC spent decades developing on a bipartisan basis.

EPSA cannot overstate the importance of final FERC orders and other follow up in the next several months putting the RTOs/ISOs on a clearer path toward timely energy market pricing reforms. This is critical because the surplus supply that generally existed when wholesale competition and restructuring began in the 1990s has been reduced as plants retired for a variety of reasons. Decisions as to whether to retire, repower, or replace large amounts of existing megawatts will continue to be made this year impacting reliability for decades. Competitive suppliers in RTO/ISO markets have proven they will respond with timely investments when accurate price signals show the need, as the results from recent capacity market auctions amply demonstrate.

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[4] *Price Formation in Energy and Ancillary Services Markets Operated by [RTOs] and [ISOs]*, Docket No. AD14-14-000, Comments of the Electric Power Supply Association (filed March 6, 2015), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13795045.

In sum, reliability in RTOs/ISOs turns on investment decisions made independently by a multitude of market participants, including developers, owners and operators of power plants as well as lenders and investors. This will not change even as the resource mix changes, new technologies are deployed, and more tools are rightly put in the hands of consumers. Market participants make economically efficient decisions as to existing and new plants when price signals are accurate and resulting revenues justify investments. These decisions are now influenced by expectations of whether identified deficiencies in Day Ahead and Real Time energy price formation will be addressed soon so future revenues are in better focus. RTOs/ISOs follow priorities set by FERC, which in turn implements the Federal Power Act as enacted by Congress. Continued Congressional, Administration, and FERC leadership is key to timely implementation of these reforms because they are essential to navigating the transformation of the bulk power system in the near term to avoid adverse consequences.

QER 1.2 Should Also Draw Attention to Medium and Longer Term Significant Issues, Including Essential Reliability Services, the Potential Need for More Fundamental Reforms to the Bulk Power System, and Threats to Competition

The electric energy price formation reforms discussed above are critical for near term investment decisions as well as for the longer term. However, looming just over the horizon to face the entire country, as presaged by what is already happening in several states and regions, are developments that may require policymakers to supplement, and potentially even later supplant, how the needs of the bulk power system are determined and financed.

First, one initial example is the relatively new concept of "essential reliability services" which are insufficiently described as "ancillary services" in past industry jargon. The North American Electric Reliability Corporation ("NERC") has recognized the importance of this subject through its Essential Reliability Services Task Force, of which EPSA and its members are active participants. NERC has educated policymakers about the critical importance of voltage support, ramping capability and frequency response. These system needs were once taken for granted as a "free" byproduct of the "rotating mass machines" that made up the power fleet. Sending specific price signals to resources able to provide these services drives investments in them where they are most needed. If less of these "essential reliability services" will be available as traditional sources of generation that provided them as a matter of course decline in light of increased intermittent and distributed resources, then "essential reliability services" must be procured and compensated separately through new and expanded market-based products. QER 1.2 can bring the electrical engineers and energy economists together to make it happen.

Second, a new area for which QER 1.2 could help jump start discussion is the potential need for more fundamental changes to the economic regulation of bulk power. To be clear, this is by no means a reason to resist changes that are afoot, but rather to anticipate areas of potential friction which can be addressed in time to smooth the transitions now underway, reliably and efficiently. For good reasons based on sound economic principles, wholesale markets were first designed in the 1990s with economic efficiency in mind. The model to achieve that goal was bid-based, security-constrained economic dispatch with locational marginal prices ("LMP").

Environmental improvement has long been a societal goal and remains so today. Wholesale markets were designed after enactment of the Clean Air Act Amendments of 1990. The tools chosen to pursue environmental goals were compatible with the LMP pricing model because the tools in earlier environmental regulations imposed direct costs on generators which could be factored into supply bids along with other costs that determined LMP prices. By contrast, increasingly today, worthy environmental goals are instead pursued through subsidies and mandates that in the aggregate may or may not achieve the intended results, certainly not on a least cost basis. Since all sources of electricity compete in the same wholesale markets, dispatch of any one source impacts the dispatch and compensation of all others. At some point, mandates or subsidies for some resources that suppress market prices, while others compete with them on a purely market basis, does not necessarily result in more net generation from lower emitting resources. QER 1.2 can help shed light on the potential market effects of various tools from which policymakers can choose to achieve their goals within markets.

Apart from excessive use of mandates or selective subsidies, the changing resource mix includes greater deployment of resources with zero to no marginal costs. An emerging challenge is to work through whether and to what extent adjustments to market rules on plant dispatch and compensation are needed as zero to low marginal cost resources such as renewables increase, while at the same time, conventional power plants with significant marginal costs will continue to be necessary. QER 1.2 should examine whether the existing LMP system based on marginal costs can work, and if not, how it could be modified, adapted, or replaced. As an example, capacity market payments will have to increase if energy pricing is not improved.

In addition, there is a need for greater analytical work around how the changing resource mix will impact peak demand. The present system is centered on reserve margins needed to meet peak demand. Some argue that new technologies and demand management can shave the peaks and avoid the need for peaking plants. More analysis is needed on the evolving and changing relationship between peak and average demand as well as on the timing or cycling of dispatchable thermal generation as non-thermal generation increases and decreases during the day. One aspect of this issue involves various points of view about whether there should be different compensation for electricity based on the location of the resource on the grid or behind the meter. This work should take into account the impact of peak demand and pricing not only on peaking plants, but on all plants at peak (baseload and mid-merit plants).

Third, as noted earlier, successive Administrations, through the Department of Energy and FERC, have pursued policies favoring wholesale electricity competition. QER 1.2 wisely includes issue subsets that should force us all to ask and answer difficult questions about what shape wholesale competition is in today as *presently* regulated. This includes whether we are taking for granted that competition will remain a viable business model *in practice* as the resource mix changes, particularly if restructured States opt for greater subsidies and mandates for some and not others; whether new regulations are imposed without making specific adjustments to allow competition to thrive in the new world upon us; and whether more resolute leadership is exerted quickly and forcefully enough when attacks on wholesale competition are about to occur, including from selective and discriminatory state-level actions that distort wholesale market outcomes and thus investment incentives.

To be clear, the competitive platform is best suited to deploying new technologies and providing greater customer empowerment. States in the first instance make a fundamental and foundational choice: rely on markets or traditional cost-based regulation. Once a State chooses markets, particularly when it separates generation from distribution and thus invites competitive suppliers to put their capital at work and at risk, States have to let the markets they helped create work. Such States cannot toggle between markets (based on marginal costs) and cost-based regulation (based on average costs). Such States likewise should not succumb to political pressures to rescue some generation from market forces through selective access to cost-based mechanisms. Once this occurs, new investments cannot be made on a market basis as intended and existing investments will be reevaluated. Any short term gain for some is heavily out-weighed by permanent damage for others, including the State's consumers. Even once a State initially chooses or maintains the traditional cost-based regulatory model, the State can produce real consumer savings by making maximum use of fairly administered competitive procurement practices to obtain the least cost resource mix.

As a result, if States do not show policy discipline after fundamental market design choices are made, the traditional approach of cooperative federalism as applied to the interstate bulk power system may not work as well as it should for much longer. Many have concerns that necessary sources of electricity facing much greater economic and technological risks are relegated to structurally lower market-based revenues, while increasingly some of those with whom they compete are swaddled in cost-based contracts not available to others. Given the interstate nature of wholesale markets, when this happens, it is incumbent on FERC to prevent market distortions.

<u>The Interaction of EPA's Clean Power Plan and Wholesale Bulk Power Markets</u>

It is impossible for QER 1.2 to consider how bulk power markets will function in future decades without taking the Clean Power Plan ("CPP") and the need to address climate change into account. In many ways, all of the bulk power wholesale market issues described above come together with greater force in the context of the CPP.

The foundation provided by wholesale power market competition has already reduced the power sector's carbon footprint and provides the basis for the CPP's major building blocks. The largest single building block is the greater use of natural gas to generate electricity. The nation would not have in place the substantial infrastructure of under-utilized, lower-emitting, high efficiency combined-cycle natural gas power plants to tap quickly were it not for the deployment of those plants by the competitive power sector starting in the 1990s. In addition, independent power producers pioneered renewable technologies such as wind and solar when traditional utilities did not. Competitive retail suppliers should have the predominant role to play in deploying distributed resources; if not, then well-meaning attempts to facilitate them will put cost-based utilities back in the very driver's seat they were wisely ejected from through restructuring. Similarly, as noted earlier, the competitive model's operational incentives result in greater capacity factors at carbon-free nuclear plants and lower emissions from more efficient operation of coal plants.

EPSA spoke at the FERC national CPP conference on February 19, 2015, stressing that FERC is uniquely qualified to address CPP aspects that might undermine competitive markets. EPSA focused on making sure the CPP is developed and implemented consistent with the bid-based, security-constrained economic dispatch used to procure the least cost mix of resources. The QER 1.2 process should do the same, emphasizing price-based CPP compliance using well-developed market structures with wider regional footprints.

FERC's expertise in assessing the power market impacts of EPA regulations was confirmed by the U.S. Court of Appeals for the District of Columbia Circuit in *Delaware Department of Natural Resources and Environmental Control v. Environmental Protection Agency*, Nos. 13-1093, *et al.*, 2015 WL 194736 (D.C. Cir. May 1, 2015) . EPSA was an intervenor and was pleased a unanimous panel overturned an EPA rule exempting behind-the-meter generators used in demand response from hazardous air pollution requirements. The court recognized the adverse effects of such a discriminatory exemption on power markets, including on cleaner sources of electricity and on the prices received by all types of plants dependent on market revenues.

Last year, EPSA released a report by The Analysis Group entitled "*Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Efficient Market Outcomes.*"[5] The report goes into detail on how the proposed CPP could have undermined competitive market outcomes in RTOs/ISOs unless these concerns are addressed. This largely stems from the state-by-state emissions rate-based approach that could produce market-distorting results given widely varying numerical targets among states within the same multi-state RTO/ISO. While the final rule largely narrowed the range of individual State rate-based targets, and provided a clearer path for greater use of mass-based approaches, the interaction of CPP implementation plans

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[5] *See*, "Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Efficient Market Outcomes," prepared as an independent report by Susan F. Tierney and Paul J. Hibbard of the Analysis Group and funded by Electric Power Supply Association, May 2015, available at www.epsa.org.

and wholesale markets will need to be monitored and managed carefully. The concern remains that similarly situated power plants will receive potentially widely varying revenue streams merely as a function of which state they are located in, even though power flows do not follow state boundaries within or even between regional markets.

Similarly, the CPP covers "existing" power plants while "new" plants (commercial operation after January 1, 2014) are not automatically covered. Thus, "new" plants operating outside of the CPP under the separately proposed New Source Performance Standards ("NSPS") could be artificially advantaged to the detriment of accurate price signals and revenues for existing plants. Under the original NSPS rules, newly constructed natural gas combined-cycle plants ("CCGT") would not incur compliance costs while similarly situated existing CCGTs could be required to do so depending on a state's emissions rate targets and implementation plan. The Analysis Group report outlined options for states to implement the CPP more consistently within regional markets, and for EPA, with FERC's help, to encourage them to place "new" power plants within the CPP so all plants competing with each other are on a level playing field. EPSA is pleased that the final CPP rule addresses this "leakage" issue, but implementation over coming years will require coordinated federal and state action.

Finally, there is a serious risk that CPP implementation could become an excuse or a vehicle for an ill-advised return to integrated resource planning ("IRP") in restructured States. IRP could become either a barrier to entry for new technologies, or an escalator for them without sufficient regard for the integrated, inter-connected bulk power system that for years to come will include both conventional and newer sources. It is unclear how IRP mandates would translate into efficient economic dispatch.

Conclusion

EPSA appreciates the opportunity to participate in this first stakeholder session of the second QER installment and looks forward to working with all relevant agencies and interested stakeholders as it moves ahead this year. EPSA commends Secretary Moniz and Dr. Holdren for their leadership and recognizes the tireless efforts of their talented staff teams for the quality of engagement and analytical work underpinning QER work products. EPSA welcomes bipartisan Congressional interest in and oversight of the important energy and environmental issues that QER 1.2 will undertake.

The in-depth, laser like focus on the electricity sector in this second installment is critical and well-timed. Much progress has been made over many decades to bring affordable, reliable and environmentally responsible electricity to every consumer, from central cities to rural counties. Doing so with innovative technologies has been accomplished in large part by tapping competitive markets. The country is entering exciting yet uncharted waters full of vast potential to harness the ingenuity of our competitive economic system, including competition in power markets, to deploy still newer technologies, further reduce emissions substantially, and improve the standard of living for all Americans.

If given the enhanced opportunity through the regulatory reforms described above, EPSA members and the competitive power sector at large will continue to be a dynamic part of maintaining reliability while pursuing important federal and state public policy goals for a stronger economy and better environment, including through the many transformational technological changes under way in how and by whom electricity supplies are generated and electricity use is managed more efficiently.