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ALBERTA MARKET RE-DESIGN – CAPACITY MARKET DESIGN AND IMPLEMENTATION

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To: Power Advisory Clients and Colleagues
From: Kris Aksomitis, Jason Chee-Aloy, Brenda Marshall, and John Dalton, Power Advisory LLC

BACKGROUND

On November 23, the Government of Alberta (GOA) announced its intention to create a capacity market within Alberta's wholesale electricity market, and released a detailed Alberta Electricity System Operator (AESO) recommendation paper titled Alberta's Wholesale Electricity Market Transition Recommendation that provides background and support for the changes being made.[1]

Structural changes to the market take significant time to design and implement, and the GOA indicated that the new market design will be in place by 2021. Consultation on the capacity market design is expected to start in 2017 and last at least two years. An additional year is expected to be required to finalize legal contracts and set up the procurement process (e.g., capacity auctions), implying that the first auction will not be held likely until 2020.

The concerns which have led to these market changes in Alberta are far from unique. Other North American wholesale electricity markets are examining structural changes to their design, generally in response to the interaction of environmental policies with existing market designs. For example:

- Ontario is considering the development of a capacity market via its "Market Renewal" initiative, and has implemented demand-response (DR) capacity auctions.

[1] See http://www.alberta.ca/documents/Electricity-market-transition-report.PDF

- New England (i.e., the ISO-New England market or "ISO-NE") currently operates energy and capacity markets and is in the early stages of determining how to adapt its market design to accommodate an influx of very low marginal cost bids (e.g., $0/MWh) from renewable energy associated with increased clean energy policy goals.
- New York (i.e., New York ISO market or "NYISO") has capacity and energy markets, and is in the early stages of determining how to implement potential structural and design changes to allow an increased focus on renewable and distributed energy uptake and development.

Power Advisory views the development of an Alberta capacity market as a positive step forward given the challenges the market will face over the next 15 years, particularly securing up to 8,000 MW of generation capacity to meet projected load growth and replace the retiring coal-fired generation fleet. During this same time, the market will also integrate 5,000 MW of renewable generation projects onto the system before 2030. How well the capacity market performs in meeting these challenges will be heavily dependent on the details of the market design and rules to be developed, as well as the specific implementation choices made during the transition period to 2030.

This note reviews the AESO's capacity market recommendation paper alongside Power Advisory's commentary, and outlines several key questions that will need to be examined over the next two years as the consultation process unfolds.

Power Advisory believes that it will be crucial for generators already involved in, or interested in participating in, Alberta's wholesale electricity market to develop a thorough and practical based understanding of the important issues and dynamics associated with capacity market design, and for generators to participate actively in the capacity market development process that will be taking place. Power Advisory consultants have extensive experience with capacity markets, capacity market design, operations of capacity markets, and assisted participants with their participation within capacity markets.

Listed below are a few of Power Advisory's qualifications regarding capacity markets.

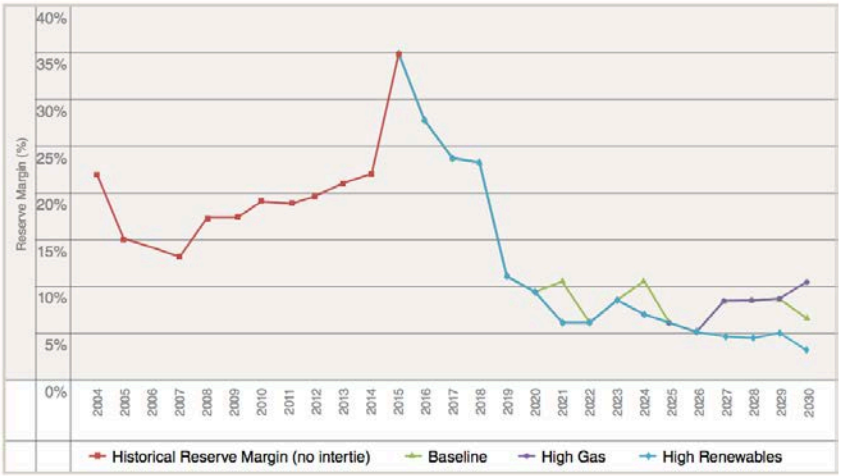
- Developed design components and rules for NYISO's initial capacity market, and presently acting for clients regarding changes to NYISO's capacity market design and rules including, but not limited to, technical assessments of generation costs and revenue requirements, filed reports within applicable proceedings before the U.S. Federal Energy Regulatory Commission (FERC), provided expert testimony within applicable FERC proceedings, etc.
- Developed models and price forecasts for NYISO's capacity market
- Technically assisted clients with the assessment and evaluation of changes to ISO-NE's capacity market design and rules, including participation within ISO-NE's present Forward Capacity Market (FCM)
- Developed models and price forecasts for ISO-NE's FCM
- Advised clients on components of Pennsylvania-New Jersey-Maryland Interconnection's (PJM's) capacity market (i.e., now called the Reliability Pricing Model or "RPM") regarding RPM design and rules
- Developed models and price forecasts for PJM RPM
- Developed detailed design and rules for an Ontario Independent Electricity System Operator (IESO) forward capacity market

Power Advisory's proprietary market modelling software has been used to forecast and analyze markets containing both capacity and energy market components. We look forward to assisting our clients as they work through the capacity market consultation process and this important market transition.

CURRENT ENERGY-ONLY MARKET DESIGN

In its recommendation paper, the AESO presented a variety of qualitative and quantitative analyses that highlighted the key issue with Alberta's energy-only market, which is that it is not expected to drive sufficient investment to maintain adequate supply margins. Figure 1 below highlights the main analytical finding that reserve margins would fall below 10% (and in some cases below 5%) with the current market design combined with the Climate Leadership Plan (CLP) objectives, therefore leading to power system reliability concerns.

Figure 1 - Historical Alberta Reserve Margin and AESO Forecasts



The AESO retained Morrison Park Advisors to gather investment views from generation investors and lenders. The key findings of this survey include the following points.

- Alberta's energy-only market is perceived as generally too risky and the current policy environment has magnified this risk
  - Energy-only markets generally have seen a shift away from the risky type of investment that they represent in global financial markets
- A structure such as a capacity market would attract a wider range of investors to the province and result in a lower cost of capital for new projects
- A contract market is seen as more attractive for investors rather than a capacity market but represents a material shift in risk from generators to consumers

Power Advisory Commentary

The AESO's analysis is consistent with Power Advisory's findings regarding the energy-only market's challenges of attracting sufficient capacity to meet supply adequacy. As reported in Power Advisory's summer 2016 Alberta Market Report and Price Forecast, even with fairly modest generator return expectations, going forward, the energy-only market design (with a $1,000/MWh price cap) would likely result in low reserve margins and increasing incidents of unserved load in order to produce scarcity pricing levels high enough to incent new generation, leading to lower system reliability. In our analysis, this problem became increasingly exacerbated with higher (and more reasonable given the levels of risk involved) generator return expectations, and became increasingly unsolvable as coal-fired generating units retired.

The qualitative analysis from Morrison Park supports Power Advisory's view that the risk and volatility associated with the energy-only market would result in higher return requirements for capacity investments. As demonstrated in Power Advisory's summer report, as well as causing lower system reliability, higher return expectations in the energy-only market lead to higher costs to consumers, as well as very volatile returns to generators.

In its analysis, the AESO shows reserve margins declining rapidly from the current level of 35%. This analysis is likely based the AESO's most recently published load growth view from May 2016 that Power Advisory believes to be optimistic given current economic conditions in Alberta. Power Advisory believes that material generation retirements would be required to drop the 2017 reserve margin to the 24% range calculated by the AESO.

While this is not a key factor in the choice of market design, a delayed drop in reserve margin would reduce the likelihood that the AESO will need to undertake 'bridge' actions[2] to ensure resource adequacy in the 2021 through 2024 period as suggested later in the recommendation paper. The AESO's optimistic load forecast also highlights a key risk with all the market designs other than energy-only – customers are put at risk for a central authority's (e.g., AESO's) load forecast errors.

Market Redesign Options

The AESO examined four potential market design options. Figure 2 below illustrates the high-level summary of the strengths and weaknesses of each option across a range of criteria agreed upon by the AESO and the GOA. The key criteria include:

- Reliable and resilient system: accommodates renewable generation, maintains supply adequacy and reserve margins, allows new technology to be incorporated and is robust to new interconnections;

[2] While the AESO does not define 'bridge' actions, the most likely action could be out-of-market contracts with capacity resources prior to the initial capacity market auction.

- Environmental performance: compatible with renewable energy development plan, distributed generation, energy efficiency, environmental policies, carbon taxes, and renewable energy uptake/new technology;
- Reasonable cost: prices to end-use customers of all types are reasonable, generator profits are reasonable, maintains an ability to hedge, competitive, maintains current risk allocation, and is compatible with measures to contain transmission costs; and
- Economic development: can incorporate social drivers, enables growth, and maintains provincial competitiveness.

Figure 2 - AESO Summary of Market Options

Policy outcomes	Electricity structure			
	Energy-only market (EOM)	Capacity market (CAP)	Long-term contract (LTC)	Cost of service regulation (COS)
Reliable and resilient system	Generally negative	Generally positive	Generally positive	Generally positive
Improved environmental performance	Generally negative	Generally positive	Generally positive	Generally positive
Reasonable cost to electricity customers	Generally positive	Generally positive	Generally negative	Generally negative
Economic development and job creation	Generally positive	Generally positive	Generally neutral	Generally neutral

Generally negative *Generally positive* *Generally neutral*

Energy-Only Market Changes

The AESO identified that the price cap will need to be raised to $5,000/MWh in order to incent sufficient capacity investment to meet reliability targets. Not surprisingly, the AESO determined that this would led to further increases in price volatility, and despite model results that suggest sufficient capacity investment, the AESO identified the high-level of risk associated with this type of a market design. In effect, it represents a 'doubling down' of Alberta's current wholesale market design and counts on even fewer hours with very high prices to drive investment. Table 1 below illustrates the risk of a $5,000/MWh price cap from AESO model results – monthly power prices can become extremely volatile. A single hour in a month near the price cap can add about $8/MWh to the monthly price or over $0.50/MWh to the annual price. The number of hours near the price cap becomes the single most important driver of overall price levels, and this is an extremely unpredictable way to incent capacity investments.

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Table 1 - AESO Energy-Only Market Model Results

	2000-2015	Sensitivities 2016-2030			
Prices ($/MWh)	**Historical**	**Baseline**	**High gas**	**High renewables**	**$5000 price cap**
Maximum	253.28	211.22	157.26	210.65	405.96
Minimum	13.63	18.53	35.16	29.71	33.47

Capacity Market

The capacity market was simply defined in the AESO's report as a two-part market structure with a competitive market for both capacity and energy. Throughout their report, the AESO recognizes that changes to the energy-only market will likely be required concurrently with the addition of a capacity market, but at this stage the proposal is simply the high-level concept of a competitive auction for capacity with a longer term than the hourly energy-only market. That is, the AESO provided no further detail or information regarding the potential design for an Alberta capacity markets.

The capacity market's key benefits from the AESO's analysis appears to be reduced risk of supply adequacy shortfalls combined with less energy price volatility. This de-risking of price and capacity outcomes is compatible with the GOA's goals and potentially leads to lower costs for new generation investments. Clearly, maintaining a competitive wholesale market was an important factor in the evaluation as well.

The report also identified the ability to link a fixed coal-fired generation retirement schedule to the capacity auctions (i.e., AESO's report refers to capacity auctions essentially as being the capacity market) as a benefit. While a transparent coal-fired generation retirement schedule does not yet exist, this appears to suggest that one will be in place to help manage the transition in a more orderly manner. Capacity markets typically have a procurement target quantity (e.g., peak load forecast plus required reserves), albeit one that can result in secured resources (i.e., generation, DR, imports) higher than the target quantity in the case of capacity markets with sloped demand curves (i.e., demand curves are used within capacity markets administered by ISO-NE, NYISO, and PJM).

Capacity markets are very complex to design, as witnessed by the constant changing design and rules of the existing capacity markets in ISO-NE, NYISO, and PJM). For Alberta, the design of a capacity market will be equally challenging and needs to be designed to factor in unique characteristics of Alberta's electricity market, therefore simply adopting design from another market will not result in addressing Alberta's specific power system needs and GOA goals and objectives. Some of the specific Alberta electricity market characteristics that need to be factored into the design include, but are not limited to:

- Facilitating continued operations of coal-fired generation prior to scheduled retirement dates;
- Facilitating continued operations of gas-fired generation (including co-generation) and preventing premature retirements;
- Facilitating continued operations of wind generation and preventing premature retirements;
- Timelines to provide capacity revenues for existing coal-fired, gas-fired, and wind generation may be different;
- Incenting timely investments in new gas-fired generation projects to effectively replace coal-fired generation as these units retire;
- Incenting entry of DR resources, and other non-generation technologies (e.g., storage); and
- Facilitating imports.

Long-Term Contract Market

A long-term contract market is akin to the Ontario market wherein most generation is contracted for periods of 20 plus years. The key aspect of this design is that risk is transferred to customers, as generators can be indifferent to market conditions depending on the design of their long-term contracts. This could increase concerns of excess generation due to forecast error, and that customers cannot benefit from technology improvements during the life of the contract.

This structure is attractive from the perspective of attracting new capital to the market as investors can build capacity with very little risk due to the contract coverage. However, the

AESO suggests that despite this potential cost advantage, customers are likely to pay more for power under long-term contracts as compared to an energy-only and/or capacity market.

Re-Regulation

The AESO examined re-regulating the market on a cost-of-service basis, and determined that the advantages provided by a competitive market outweigh the direct benefits of lower capital costs and the ability to directly plan the system. The risk of locking into technologies for effectively the life of assets was identified as a key issue for this structure, as was the lack of incentives to innovate and reduce costs.

The AESO also evaluated the difficulty, measured in terms of costs and risks, of transition for each option as summarized in Figure 4 below.

Figure 3 - AESO Market Transition Difficulty Ratings

Policy outcomes	Electricity structure			
	Energy-only market (EOM)*	Capacity market (CAP)	Long-term contract (LTC)	Cost of service regulation (COS)
Orderly transition — costs	Low	Medium	High	High
Orderly transition — risks	High	Medium	Medium	High

High *Low* *Medium*

** EOM represents costs and risks of introducing enhancements*

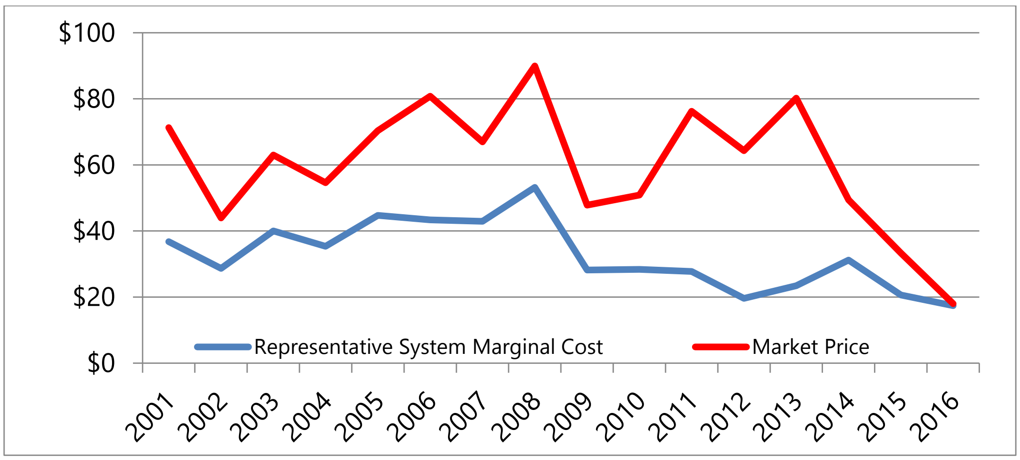
Power Advisory Commentary

The AESO's analysis of the benefits of various market designs highlights that in picking an overall market design there is a continued belief that allocating market risks to capacity resources will minimize costs to customers and result in a more flexible and innovative system.[3] This is in contrast to the current round of renewable generation procurement under the Renewable Electricity Program (REP) where the advantages of long-term contracts will exist.

[3] The Indexed Renewable Energy Credit (REC) structure that the AESO is proposing for the REP shields renewable generators from market risks. So, market risks are not being allocated to all generators, just capacity resources.

The reduction in price volatility was highlighted as a benefit of capacity markets relative to the energy-only market. Figure 5 illustrates historical Alberta power prices as well as representative estimates of what market prices would have been based purely on marginal cost. (Unlike Alberta's current market design, marginal cost bidding in the energy market is a common feature within many jurisdictions with capacity markets.) At an annual level, there is less volatility in energy prices, though there is potentially additional yearly volatility not shown resulting from the capacity market itself. Monthly volatility should be reduced if capacity costs are spread out annually.

Figure 4 - Alberta Power Price and Representative System Marginal Cost



One of the implications of altering energy market price signals is that winners and losers may be created. Some generators may be more attractive in a capacity market design relative to an energy-only market, and vice versa. Managing these divergent interests in the development of an efficient capacity market will be a key element of the consultation process.

Power Advisory believes that smoothing the transition from retiring coal-fired generation to developing gas-fired generation within a capacity market is prudent. Many investors are familiar with capacity markets and with appropriate design parameters the market should attract new investment. A capacity auction three plus years forward, as is typical for some capacity markets (e.g., ISO-NE, PJM), should allow developers to line up new projects to compete within respective capacity auctions for years with a clear need for new capacity. This also reduces the risk of an overbuild – if coal-fired generators are retired in an orderly fashion (i.e., at known dates) overbuilds will be avoided.

Alberta will be seeking to attract significant new supply in a short period of time after transforming the existing energy-only wholesale market. The shift from the energy-only design to inclusion of a capacity market is critical – if the capacity market is to work it must deliver sufficient confidence for investors. As noted in the Morrison Park report's appendix, "While close to half of the report participants expressed support for capacity markets – and therefore a significantly greater number than support the existing energy only market – this support was mitigated by comments about the challenges associated with setting up such [capacity] markets, the need for time for markets to mature, and many other details".[4] This risk implies Alberta will likely need to allow for a relatively long 'lock in' period[5] for new project development in order to attract investment into a newly formed market.

The interaction between renewable generation procurements within the REP, other GOA policies, and the design of Alberta's capacity market will also be important in determining the capacity market's success. Other capacity markets, such as California, have seen persistently depressed prices partially as a result of interactions with policy driven renewable generation procurements resulting in long-term contracts. The role and compensation of renewable generation that supply relatively higher capacity value (e.g., hydroelectric generation) will also need to be considered to ensure coordination across markets and other programs.

SUMMARY AND KEY DESIGN QUESTIONS

As noted, the AESO recommended that Alberta implement a capacity market and the GOA has accepted this recommendation. The timeline the AESO has identified indicates that stakeholder consultation will occur throughout 2017 and 2018, and contracts (i.e., AESO identified 'contracts' as a means to secure resources that successfully participated within the

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[4] http://www.alberta.ca/documents/Electricity-market-transition-report.PDF, Appendix A, Page 6.

[5] For example, ISO-NE allows new developers to lock in their initial capacity price for a seven year period in order to incent new development.

capacity auction[6]) will be developed in 2019. The AESO further indicated that delivery of the first new capacity from auctions will not be available until 2024 (i.e., a 2020 auction for 2024 delivery).

It is unclear what the plan for the bridge period of 2021 through 2023 entails. Based on the AESO's report and the GOA's news release that suggests a 2021 target for the new market design, it appears as though capacity auctions are intended to occur for 2021 through 2023, but new resources may potentially not be included (or at least the AESO may not believe new resources can be on-line prior to 2024 from a 2020 auction). Depending on the volume of coal-fired generation retirements expected in 2021, this raises issues around the competitiveness of the initial auction (assuming capacity payments are in place for 2021 from a 2020 auction for existing resources). DR and the ability of imports to compete would likely alleviate many 2021 concerns. In its November 24 news release[7], TransAlta stated that it is committed to converting six of its existing coal-fired generation facilities to gas-fired operation by 2023, raising the possibility that early capacity market procurements may favour incumbent generators.

The GOA has indicated that the AESO will be procuring capacity contracts on behalf of all load, which resolves one of the key design elements within a capacity market, but there are many more elements yet to be designed.

The AESO identified a large number of high-level details that will be worked out through an estimated two-year stakeholder consultation period. Areas identified for discussion and inferred from the paper include the following questions to be answered listed below.

- How will loads with co-generation and other on-site generation be treated?
- How will the capacity cost be charged to loads?

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[6] Power Advisory believes 'contracts' should not be literally interpreted where the AESO executed Power Purchase Agreements (PPAs) or similar, rather a loose interpretation should apply where 'contracts' likely refer to some form of financial commitment where resources are paid capacity revenues from the AESO for a pre-determined period of time. That is, presumably the AESO is referring to the terms associated with capacity obligations procured under a centralized auction as 'contracts' rather than a bilateral contract with unique terms for each generator.

[7] http://www.transalta.com/newsroom/news-releases/2016-11-24/transalta-reaches-agreement-government-alberta-transition-payments

    - Spread across all hours or directed towards high load hours
- How will energy efficiency and DR resources fit into the market design?
- Will locational signals be improved or will other tools be developed to manage rising transmission costs?
- Will a transition mechanism be required in 2021 to 2024?
    - Will coal-fired generation retirements be accelerated into 2021 and create a supply need even absent material load growth?
    - Is there a risk of coal-fired generation retirements that trigger short-term bridge capacity payments for those same units due to this bridge period?
- What changes will be required to the energy market with the addition of a capacity market?
    - Offer behavior guidelines
    - Day-ahead markets
    - Co-optimized energy and ancillary services markets
- How is the need for capacity determined and what is the shape of the demand curve?
    - Vertical vs. sloped demand curve
    - AESO forecast methodology and risk tolerances
    - Capacity contribution from different resources
- Auction design
    - When is the auction relative to delivery obligation?
    - How often are auctions held?
    - What is the term of capacity contracts?
    - Are new units treated differently than existing units (i.e., can new units 'lock in' a price for the first five to 10 years (seven years allowed in ISO-NE))?
    - Are new units price-setters and existing units price-takers?
- How are different types of assets treated? What are the performance provisions? How does the market design discern differential value between different asset types?
    - Energy constrained resources
    - Variable resources
    - Long-lead time resources
    - Intertie resources
    - DR and energy efficiency
    - Co-generation

Suite 380, 435 4th Ave SW • Calgary, AB
587-894-7150 • kaksomitis@poweradvisoryllc.com

- Will the market be sufficiently competitive given the small size of the Alberta market? Including DR and interties can improve the competitiveness, but both resources have raised complications in other jurisdictions.

In general, existing capacity markets in North America have addressed many of these questions in different ways and no one capacity market model is a perfect fit for the Alberta context. The AESO consultation will be a very complex process, and the proposed two-year timeline will likely be a challenging one to achieve.

Power Advisory Commentary

The list of capacity design questions provided by the AESO as listed above all need to be addressed in consultation with stakeholders.

In addition to these questions, based on Power Advisory's knowledge and experience with capacity market design and operation along with Alberta's electricity market design and structure, listed below are key 'building block' points that need to be thoroughly addressed within the design of Alberta's capacity market in conjunction with the AESO's questions.

- Load forecast techniques, including input variables
- Determination of reserve margin
- Determination of an Alberta resource adequacy requirement (RAR) (i.e., load forecast plus reserve margin), which will essentially be the capacity target quantity to maintain Alberta's power system reliability
- Determination whether locational RARs are needed (i.e., different RARs) based on transmission congestion, where locational RARs may not be required for the initial capacity auctions but may be required over time as Alberta's supply mix changes which in turn will likely change power flows on Alberta's grid
    - e.g., ISO-NE and NYISO capacity markets have locational markets with different RARs
- Determination of individual resource capacity contributions during future periods when Alberta is projected to most need energy productions (i.e., metrics to determine energy production performance during peak demand periods)

    - Capacity contributions will be different based on resource fuel-type, vintage of resource, to be developed resource, etc.
- Determination of forward delivery period (i.e., time from respective capacity auction that energy must be available to be produced) and commitment periods (i.e., period of receiving capacity payments from AESO based on respective capacity auction clearing price)
    - Forward delivery and commitment periods may be different for different resources
- Determination of potential need for re-balancing auctions in order to address resource need changes closer to the beginning of respective delivery periods
- Determination of auction bidding rules
- Determination of how capacity prices are set per auctions and how resources successfully bid into these auctions and clear these auctions
- Determination of how to mitigate potential exercises of market power within capacity auctions
- Determination of requirements of cleared capacity resources to participate within the wholesale energy market (e.g., 'must offers')
- Determination whether any performance penalties/rewards are required regarding compliance with dispatch instructions within the wholesale energy market