Optimizing Reserves

Recommendations for the U.S. Department of Energy

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ELECTRICITY ADVISORY COMMITTEE

Optimizing Reserves

Introduction

Operating reserves are needed to ensure that additional energy is available in response to numerous possible system events. "Spinning reserves" – one type of operating reserves – are the unloaded portion of generators that are online already and can quickly increase their output to their maximum ratings to meet changes in demand. Other operating reserves can be provided by offline generators that an operator can turn on when needed (known as 10-minute "quick start" units) but which cannot respond immediately as spinning reserves. Operating reserves help to restore balance to the system following large losses of resources, such as the balancing authority's largest single generating contingency. Both kinds of reserves are critical to reliability of the grid and should be optimized. (Note: Some regions allow other types of resources to provide operating reserves, such as demand response, storage, etc.)

While spinning reserves can respond rapidly to a sudden need for more power, this ability comes at a cost. Running a plant at levels below its maximum optimal operating point in order to provide spinning reserves can cause inefficiency in the provision of energy from individual resources, while increasing costs by requiring more plants to be online. The growing dependence on variable wind and solar power resources make it more necessary to balance reserves to cover minute-to-minute and hour-to-hour variability and uncertainty. Additionally, other power electronic interfaced resources (such as battery storage) and electronically-coupled load also can respond quickly if required after an event.

The changing energy landscape, including the increased levels of variable energy resources and other emerging technologies, is driving the need to reconsider the industry's traditional approach to reserves.

Operating reserves, including spinning reserves, have long been required by North American Electric Reliability Corporation (NERC) standards. All balancing area authorities in the United States require a minimum capacity of spinning reserves to be kept online at all times in case of sudden losses of generation or unexpected changes in net load. These spinning reserve requirements have become embedded within the grid codes of utilities, ISOs, and RTOs worldwide.

With traditional technologies, minimum spinning and operating reserves were necessary to prevent generation-load imbalances from leading to unstable drops in frequency and other issues. This helps avoid activation of under-frequency load shedding (UFLS) systems, which trip loads at predetermined low frequencies to prevent complete system collapses. Additionally, generator under-frequency protection systems are typically designed to trip generators offline if frequency approaches levels in which turbine blade resonance may damage equipment.

With more and more resources using power electronic interfaces and the retirement of some traditional synchronous generating resources, inertia on the system is being reduced. One characteristic of lower inertia is a more rapid and deeper decline in frequency (measured by the rate-of-change-of-frequency – RoCoF) after an event. However, with intelligent controls enabled, these power electronic interface resources can respond by injecting replacement energy more quickly and accurately than traditional synchronous generation, to arrest the frequency decline and recover frequency faster. It should be noted that such response requires energy to be readily available to inject into the system from batteries, flywheels, or curtailed wind or solar resources.

At the same time, reserve requirements and definitions are changing globally as new types of services (such as fast frequency response) are being defined. These services also interact with each other. For example, an increase in quick-response reserves from inverter-based resources reduces the need for slower-acting reserves from traditional technologies. Significant economies may be realized by revising these reserve requirements and definitions. However, the tradeoffs and benefits of different technologies should likely be fully assessed.

Recent developments in new technologies—such as storage, load management, advanced predictive capability, and the demonstration of new inverter capabilities—have the potential to contribute to spinning and other reserve requirements.

Many ISOs and RTOs have expanded their definitions of reserves to allow some new technologies to provide reserve products that do not meet the historic definition of "spinning."[1] This allows new ancillary reserve services that complement the UFLS systems.[2] Though reserve requirements may not have been reduced, the effective amount of "spinning" reserves from online resources operating at non-optimal levels on their heat rate curves is less, and thus the economic efficiency is improved. These policies are inconsistent across the United States, potentially making reserve markets fragmented and less efficient.

Approach

The Electricity Advisory Committee (EAC) hosted a panel discussion with experts on the topic at its June 2019 meeting. EAC Members and panelists engaged in a robust discussion after the topic was introduced and panelists gave their presentations. The panel explored the needs and costs of maintaining reserves, as well as the potential benefits and tradeoffs of replacing traditional spinning reserves with newer technologies while optimizing overall reserve requirements. The panelists addressed the following questions:

1. What are reserve requirements today, and in what ways can we challenge the traditional thinking given industry transformation with respect to data and technology?
2. What is the optimal level of reserves? (What variables must be considered in this determination and to what extent can new technologies and/or improved forecasts reduce the necessary level of reserves, and what are the benefits of doing so?) How do these reserve requirements change with larger penetrations of wind and solar?
3. What are reserve requirements for different regions across the United States? How do these requirements compare to the optimal levels described above?

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[1] For example, see the Electric Reliability Corporation of Texas (ERCOT) standards for ancillary service quantities, http://www.ercot.com/content/wcm/libraries/188854/September_1__2019_Nodal_Protocols.pdf, and PJM's Balancing Operations Manual (https://www.pjm.com/-/media/documents/manuals/m12.ashx) and Emergency Operations Manual (https://www.pjm.com/-/media/documents/manuals/m13.ashx).

[2] This refers to the provision in some electricity markets of an ancillary service product allowing the sale of load shedding services in place of spinning reserves. These services are allowed only as long as they are guaranteed by placing the load to be shed behind automatic switching devices (high-set relays) which automatically shed the load at system frequencies well above the provisions described in NERC EOP-003.

4. If the reserve requirements are at other than an economically optimal level, what changes are appropriate to increase economic efficiency?
5. If changes are made to reserve requirements obligations across the United States, would these changes attract investment and increase economic efficiency?
6. What is the cost (in dollars, emissions, efficiency penalty, and/or opportunity cost) of maintaining traditional spinning reserves?

Findings

Though the panel discussion provided many insights, the discussion concluded with more questions than answers. Below are key takeaways:

- Today's NERC standards will need to evolve with the changing nature of both the reserve and reliability needs of the grid.
- Markets were designed with the premise of reliability at least cost; however, new technologies and priorities (e.g., environmental considerations) might drive modified approaches to capacity and energy markets with respect to reserves.
- Primary contingency reserve calculations using N-1 might need to be supplemented with a greater focus on frequency response needed.
- The increased variability of resources within generation portfolios and uncertainty of events are beginning to drive reserve requirements.

Recommendations

EAC Members developed recommendations to the Department of Energy (DOE) based on suggestions from the panelists and opinions of the EAC Members. The higher priority recommendations are provided below.

Recommendation 1: Defining Operating Reserve Requirements

DOE should consider (or expand/prioritize) efforts to quantify uncertainty and variability for the purposes of determining reserves requirements and initiate discussions with NERC regarding the appropriate risk and reserve methodology.

DOE is in a unique position to expand existing efforts on determining uncertainty to additional markets and areas of the United States. Understanding that the N-1 approach does not effectively capture the growing uncertainty as a result of renewables and other technologies, this broader approach could help drive industry standards related to how reserves are calculated and valued in markets. This approach will help drive the reserve optimization that we seek across the industry.

While probabilistic efforts are underway to begin to address solar uncertainty and forecasting, there is an awareness that needs to vary by region. DOE should expand existing efforts and research to determine optimal reserves requirements.[3] Such expansion might include considerations that are more prevalent in certain areas of the country such as natural gas resource (pipeline) disruption, or potential susceptibility to weather-related contingencies (low wind or heavy cloud cover), and other variabilities or uncertainties.

[3] The Electric Power Research Institute (EPRI) has created a tool to quantify appropriate reserve levels, which could serve as a good starting point.

The North American Energy Resilience Model (NAERM) could also be used to model the three U.S. interconnections with respect to prospects of lower inertia and greater intermittency. Can the NAERM model the demand-side effects as well?

The accurate modeling of distributed power electronics (e.g., inverters) and controllable loads may support market mechanisms in pricing the reserve products provided by these devices.

NERC and other industry standards that drive reserve requirements should be modified to accommodate new determinations.

Recommendation 2: Performance Requirements for New Resources

DOE should consider analysis defining technological and operating requirements for new resources that might reduce the dependency on operating reserves.

Generating units were historically designed to operate in a different performance mode from what is needed for the modern grid. Traditional governors, for example, may have a 3 to 6-second response time when a 1 to 3-second response is required to arrest frequency declines for events with very high RoCoF. Performance metrics could also help drive a more optimal operating reserve requirement. For example, is it worthwhile to create a requirement for governor-like droop settings on inverter-based resources and storages devices of 5% to 4% during normal operations? Other suggestions from the panel discussion were:

- Ensure that renewable resources—including storage devices—provide essential reliability services, including voltage control, frequency control and response, and ramping capability.
- Impose a steady-state ramp rate of 10% of the maximum capability of the unit (P max) to help manage variability in real-time.
- Reduce governor deadbands on resources from 0.036 hertz to 0.01667 hertz.

Various interconnections meet the reliability need to respond to frequency disturbances on the grid with additional mechanisms, including but not limited to fast-acting, frequency-responsive load response and quick-starting resources. DOE could identify limitations in the grid rules of the three major interconnections, which are creating sub-optimal limitations in responding to grid disturbances. What can be done to investigate and support the development of inertial response from the demand side?

Recommendation 3: Valuing Operating Reserve Needs for Optimization

DOE should explore market designs to appropriately value operating reserves once an optimal amount is determined.

Existing market designs were not created with variable generation or renewable resources in mind. They were designed for controllable supply and dependable demand. With the large amount of renewables on the grid—especially during midday on weekends, when loads are low and solar generation goes up—the excess generation can create performance issues.

Traditional markets need to be redesigned. Nothing in market design today allows units to reverse course after they are locked in for a time interval. How can we tie system frequency back into market operations and pricing?

Recommendation 4: Convening

DOE should host a federal-state effort to help inform the governance needed to advance industry-wide reliability and market changes related to reserves.

With the current regulatory structure, it is difficult to drive change. This matter fits squarely within both state and federal jurisdiction, with states increasingly engaged in distribution resource matters and incentives. To reach an optimal solution, state and federal stakeholders will need to agree on the direction and then the solution.

For example, how can distribution-connected resources provide wholesale market services?

Conclusion

Operating reserves and how they are thought about must evolve with the industry. The amount of operating reserves required should consider the increasing rate of intermittent and natural gas resources on the grid. It also should accommodate the electrification and increased demand-side management efforts. Technology is changing and the optimizing operating requirements dictate that we rethink how we determine the future needs and values of this requirement.