NODES Program Overview

B. PROGRAM OVERVIEW

Program Vision

The infrastructure that defines the U.S. electric grid is based largely on pre-digital technologies developed in the first part of the 20^{th} century. Through subsequent decades, grid development has evolved through emphasis on safety, accessibility, and reliability to security and resiliency. But the evolution of the grid now faces significant challenges in flexibility if it is to integrate and accept more energy from renewable generation and other Distributed Energy Resources (DERs) (e.g. rooftop photovoltaic and home energy-storage). The addition of intermittent generation along with changing usage patterns (e.g. increased penetration of electric vehicles) is leading to greater uncertainty and variability in the electric grid that may have a significant impact on grid reliability. However, a potential opportunity exists for these changes to be utilized to the benefit of the grid, with the deployment of the right control and integration technologies.

The **N**etwork **O**ptimized **D**istributed **E**nergy **S**ystems (NODES) Program aspires to enable renewables penetration at the 50% level or greater, by developing transformational grid control algorithms and architectures that optimize the usage of flexible load and DERs. The challenge is to reliably manage, locally or globally, dynamic changes in the grid by leveraging these additional grid resources, while having minimal impact on customer quality of service (QoS). The expected system level benefits include net energy savings, reduction of CO_2 emissions in power generation by directly offsetting load consumption by renewable energy production, and lowering required operating reserves. Additional savings are expected to be achieved by supporting higher penetration of Distributed Generation (DG) that is expected to reduce energy-delivery losses by delivering energy where it's needed, and when it's needed.

A significant reduction in fossil fuel consumption and CO_2 emissions may be realized through the NODES Program. A preliminary study of the impact of a NODES approach on flexible load and DERs integration was completed for the PJM market (~20% of US electricity market) with a simulated 50% penetration of renewable generation resources.[1] The results were extrapolated to represent the entire US market. Compared to a baseline scenario of no load or DERs flexibility, the curtailment of VERs was reduced from 21% to 6%, offsetting 3.3 quads of thermal generation and displacing 290 MT of CO_2 emissions. Additionally, 4.5 GW of spinning reserves could be replaced with flexible load and DERs, a value of $3.3B per year. However, all of these benefits are in addition to the ability to transition from current penetration of renewable energy (16% for PJM) to 50% penetration. This transition would have otherwise been limited due to the declining capacity factor of renewable generators as greater amounts are curtailed to maintain the base-load generation, leading to increased Levelized Cost of Energy (LCOE).[2]

The future U.S. electric grid requires real-time adaptation by advanced controls to enable an interconnected power system, with a high level of renewable generation and a large number of DERs with the ability to reliably integrate customer side assets while providing benefits to system users. Traditionally, hierarchical control architectures defined by time-scale separation have been the engineering approach of choice for control of complex dynamical systems, as it is reflected in the grid's current top-down management structure. More recently, distributed control architecture has been explored as an alternative solution for large-scale system control, where system decomposition presents the major challenge. Accordingly, the power systems community has recently began looking into alternative grid management architecture that would enable seamless integration of numerous DERs into the grid, leading to more efficient grid operation and reduced CO_2 emissions. Proposed grid control architecture solutions vary from having ISOs manage the entire grid top-to-bottom, to running grid as a network of micro-grids. The NODES Program aims to explore which architectures and corresponding resource aggregation approaches will allow consumers and grid operators to adapt their

[1] GE Energy Consulting, Jovan Bebic´, Gene Hinkle, Slobodan Matic´, and William Schmitt, "Grid of the Future: Quantification of Benefits from Flexible Energy Resources in Scenarios With Extra-High Penetration of Renewable Energy", Nov 2014.
[2] GE Energy Consulting, Jovan Bebic´, Gene Hinkle, Slobodan Matic´, and William Schmitt, "Grid of the Future: Quantification of Benefits from Flexible Energy Resources in Scenarios With Extra-High Penetration of Renewable Energy", Nov 2014.

operations to achieve significant improvements in system-wide operational cost and energy efficiency. If successful, the NODES Program will leverage advances in computing and data communications to enable control of load and distributed generation and facilitate large-scale renewables integration.

This program will build on grid-wide sensing, and energy efficient building control improvements accomplished over the past decade that have broadened the number of grid edge assets that can be controlled. It will integrate benefits from other federal programs, including: the Department of Defense's Environmental Security Technology Certification Program (ESTCP)[3]; the DOE Office of Energy Efficiency & Renewable Energy's (EERE) SunShot initiatives[4] on distributed solar integration; flexible load programs in EERE's Building Technologies Office (BTO)[5]; and the DOE Office of Electricity's (OE) "Integration of Variable Renewable Generation using Demand Response" program.[6] By focusing on developing technologies that enable novel functionalities at the distribution level and facilitate seamless integration of flexible load and distributed energy resources into the grid, NODES will complement programs aiming to integrate renewables into the electric transmission system such as ARPA-E's Green Electricity Network Integration (GENI) Program[7] and OE's *Advanced Computational and Modeling Research for the Electric Power System.*[8]

Recent advances in sensing, communication, and asset control enable the creation of a new paradigm for grid operations that utilizes novel system architectures and active control of load side resources to provide additional reserves and grid balancing services. At high deployment levels, DERs can collectively become a valuable system asset if coordinated with system needs and control processes, as they are very fast acting, and are close to the loads. In addition, with improved load and generation forecasting, and the introduction of local control and coordination algorithms DERs could easily provide timely services to the grid and could be integrated into the current power grid. At the same time, these technologies will provide a vehicle for the long-term transformation to a future grid that equally benefits from all assets, regardless of their placement at the distribution or transmission level.

The NODES Program is intended to bring together different scientific communities, such as power systems, control systems, computer science, and distributed systems to accelerate the development of new technologies enabling active control of load and DERs in coordination with the grid, and engage with stakeholders who can drive these new operational approaches towards market adoption. ARPA-E strongly encourages teaming among experts from these interdisciplinary technical fields in responding to this FOA in order to have the sufficient breadth of expertise necessary to achieve the targeted advances in the management and control of the electric grid.

Current Grid Management

The dominant paradigm for delivering electricity in the U.S. consists primarily of bulk electricity generation at central power plants (coal, Natural Gas Combined Cycle (NGCC), nuclear - and more recently - wind farms and centralized solar), followed by transport across the U.S. electrical grid via Transmission and Distribution (T&D) networks, and finally delivery to the end-user. This energy generation paradigm is complemented by peaking energy generation that provides additional capacity during peak use hours, as well as other ancillary services[9] such as operational reserves, voltage regulation, load following, contingency reserves, etc.[10] At any given time, power generation must match the load to maintain grid reliability.

[3] ESTCP energy projects https://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy.
[4] Funding awarded in response to DoE EERE FOA DE-FOA-0000479, https://eere-exchange.energy.gov/Default.aspx?Search=DE-FOA-0000479, announced in April 2011.
[5] BTO's load control strategies, http://energy.gov/eere/buildings/building-technologies-office-load-control-strategies.
[6] Lawrence Berkeley National Laboratory, http://emp.lbl.gov/projects/integration-variable-renewable-generation-using-demand-response.
[7] http://arpa-e.energy.gov/?q=arpa-e-site-page/view-programs
[8] Funding awarded in response to DoE FOA DE-FOA-0000729, https://www.fedconnect.net/FedConnect/PublicPages/PublicSearch/Public_Opportunities.aspx, announced in May 2012.
[9] FERC defined ancillary services as those "services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."
[10] U.S. Federal Energy Regulatory Commission (FERC), "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities", Docket RM95-8-000, 1995.

Currently, 87% of the 4058 Billion kWh of electric energy used annually in the U.S. comes from the central-station thermal generation fleet.[11] Historically, the primary benefit of this centralized approach to power generation has been that energy conversion is more efficient and cost effective at scale.[12] The centralized energy generation system generates more than 2 billion tons of CO_2 emissions annually.[13] The average conversion efficiency of the US fleet is 32.5% for coal and nuclear, and 42.4% for gas[14] utilizing a blend of combined cycle and simple cycle plants. In addition, the total T&D losses are 6%.[15]

Over the course of each day, the central-station generation fleet is committed (brought on-line) and dispatched (brought to a desired output) to follow the system load. Currently power plant dispatching is based on system load forecasting and is performed at various time horizons subject to control area's transmission system size and constraints. The unit commitment process ensures that the committed generation hour-by-hour has adequate margin to serve the load according to North American Electric Reliability Corporation (NERC) standards.[16] Transmission constraints can be determined by either thermal limits or voltage/transient stability limitations depending on the timeframe of the problem being addressed. These limits are most often a consequence of system security and reliability requirements, such as adequate system recovery after disturbances, which are stipulated by NERC planning standards (TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a.[17] [18] [19] [20]

Notably, the NERC planning standards consider the load as non-dispatchable and unable to contribute to dynamic system recovery. These practices give rise to two major areas for improvement in operation of the central station fleet: the proactive shaping of load over all relevant time horizons, and reducing the effect of transmission limits due to the potential ability of load and DERs to positively contribute to dynamic system recovery.

Current Limitations of Renewable Energy on the Grid

The installation of renewable electricity generators such as solar and wind is a growing trend in the United States,[21] driven in part by the rapidly falling cost of renewable generation technologies,[22] renewable portfolio standards (RPS) in 27 states, and net metering policies or other efficiency incentives in 43 states.[23] Because their fuel is free, renewable sources of energy typically exhibit very low marginal costs and are most often operated at their maximum available output, which makes them non-dispatchable. Additionally, due to the intermittency of solar and wind energy, the available output magnitude for renewables typically changes in a continuous manner, hence these are termed Variable Energy Resources (VERs). Today, renewables penetration is limited (less than 30%, PJM Report[24]) because these technologies lack the ability to reliably and affordably manage their dynamic variability.

To maintain reliability, system operators must continuously match the demand for electricity with supply on a second-by-second basis. Historically, the Independent System Operator (ISO) directed thermal, controllable power plant units to move up or down with the instantaneous or variable demand. Demand has always been variable and system operators

[11] U.S. Energy Information Administration, "What is U.S. electricity generation by energy source?" http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3, accessed: 2014-10-23.
[12] "Catalog of CHP Technologies," U.S. Environmental Protection Agency Combined Heat and Power Partnership (2008).
[13] U.S. Energy Information Administration, http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11.
[14] "Average Operating Heat Rate for Selected Energy Sources," http://www.eia.gov/electricity/annual/html/epa_08_01.html, accessed: 2014-10-23.
[15] "How much electricity is lost in transmission and distribution in the United States?" http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3, accessed: 2014-10-23.
[16] North American Electric Reliability Corporation, "United States Mandatory Standards Subject to Enforcement," http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States, accessed: 2014-10-23.
[17] NERC Transmission Planning Reliability Standard TPL-001-0.1, "System Performance Under Normal (No Contingency) Conditions (Category A)", http://www.nerc.com/files/TPL-001-0_1.pdf, May 2009.
[18] NERC Transmission Planning Reliability Standard TPL-002-0b, "System Performance Following Loss of a Single Bulk Electric System Element (Category B)", http://www.nerc.com/files/TPL-002-0b.pdf, October 2011.
[19] NERC Transmission Planning Reliability Standard TPL-003-0b, "System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)", http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-003-0b.pdf, June 2013.
[20] NERC Transmission Planning Reliability Standard TPL-004-0a, "System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)", http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-004-0a.pdf, June 2013.
[21] U.S. Energy Information Administration, "Annual Energy Review," http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf, Figure 8.2a, 2011.
[22] Galen Barbose, Samantha Weaver, and Naïm Darghouth, Lawrence Barkley National Laboratory (LBNL), "Tracking the Sun IIV: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013", September 2014.
[23] http://www.dsireusa.org/documents/summarymaps/net_metering_map.pdf.
[24] PJM, "Renewable Integration Study Report", https://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx, 2014.

have always been required to match these variations with controllable resources (mostly dispatchable thermal generation). However, studies have shown that with high levels of non-dispatchable VERs, matching generation and demand in the grid becomes more difficult[25] because system operators must directly control resources to match both variable demand and variable supply.

Installation of variable, intermittent, and non-dispatchable generation technologies, such as solar photovoltaic and wind turbines, poses fundamental challenges to centralized power system management practices due to the variability and unpredictability they introduce into the system. Traditionally, most of the grid support services required to maintain system stability were provided by bulk power generation resources that could be quickly dispatched and ramped-up to generation levels required to maintain system balance. To maximize renewables and DERs integration in the future, all grid generators and flexible loads are expected to address and support system stability in accordance with their resource characteristics and technical capabilities. However, net-load control schemes would need to address various challenges in order to have significant effect on grid services and achieve prevalent industry adoption. These challenges include: coordinated management of large numbers of heterogeneous types of loads and DERs with various behavioral characteristics, guaranteed availability of negotiated Level-of-Service (LOS), and automated adaptation to real-time variability in the LOS required by the system and flexibility limits of loads.

One problem of matching generation and demand with high penetration of VERs is clearly illustrated by current and projected curves for net load as a function of time during the day, as shown for California ISO area in Figure 1 below. Net load is the difference between the forecasted load and the expected electricity production from VERs. The “duck curves” for future scenarios with high solar penetration illustrate the potential for over-generation during peak solar production hours and the need for very fast ramping from thermal generation to meet peak demand later in the day, following the peak of solar production.

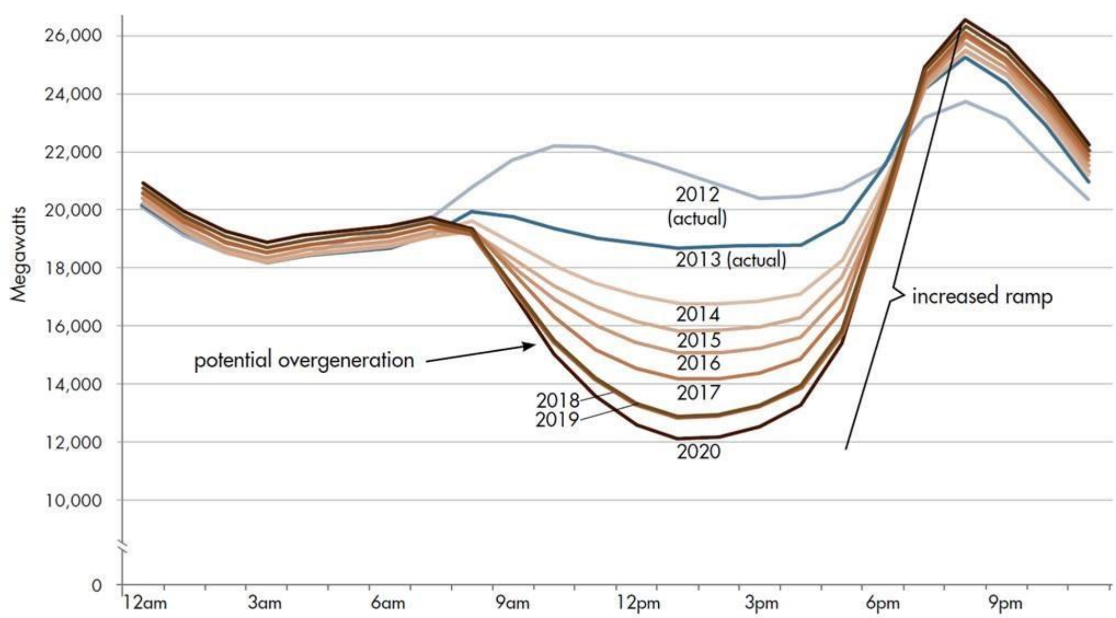

Figure 1: Net load curve for California, from 2012 to 2020, showing the difference between forecasted load and expected electricity production from variable renewable sources in a 24-hour cycle[26]

Balance of supply and demand directly affects system frequency. Thus, to ensure grid reliability, system frequency must be managed in a very tight band around the system’s design frequency of 60 Hz. When an unexpected event occurs that disrupts the supply-demand balance, such as a loss of a generator or transmission line, frequency is impacted. These events do not allow time for manual response and balance is maintained through automated equipment. Conventional generation resources include frequency-sensing equipment, or governors, that automatically adjust electricity output within seconds in response to frequency to correct out-of-balance conditions. Figure 2 below shows the Under-Frequency

[25] R. Masiello, et al., “Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid,” prepared for the California Energy Commission (CEC-500-2010-010) (2010).

[26] California ISO, http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Load Shedding (UFLS) threshold, frequency nadir, and settling frequency points during a frequency excursion caused by a loss of generation event.

Renewable generators are not currently required to include automated frequency response capability (i.e. no frequency reserve) and are operated at full output (i.e. they cannot increase power). Thus, as renewables begin to displace conventional generation, the total system inertia decreases, and additional contingency reserves are required to restore the system frequency to the reference value after contingency events. Even more problematic are renewable resources connected at the distribution level that have historically been required to trip offline during relatively small frequency excursions, meaning that a loss-of-generation event could be exacerbated by a sudden loss of all of the renewable DG resources within a control area[27]. This combination of factors makes the system more vulnerable to blackouts when generation or transmission outages occur.[28]

Recent studies have shown the short-term response of the power-system frequency to large mismatches between generation and load, and showcase how frequency nadir and settling frequency change in different scenarios.[29] Inadequate balancing reserves and/or transmission resources have already led to curtailment of renewable power in both the Electric Reliability Council of Texas (ERCOT) and the Bonneville Power Administration's (BPA) system.[30] Introduction of new grid control and optimization algorithms taking advantage of DG and load flexibility in the U.S. could directly contribute to the grid reliability and could have additional potential benefits, such as the reduction of renewables curtailment, peak load, T&D congestion, and grid vulnerability, in addition to improving power quality.

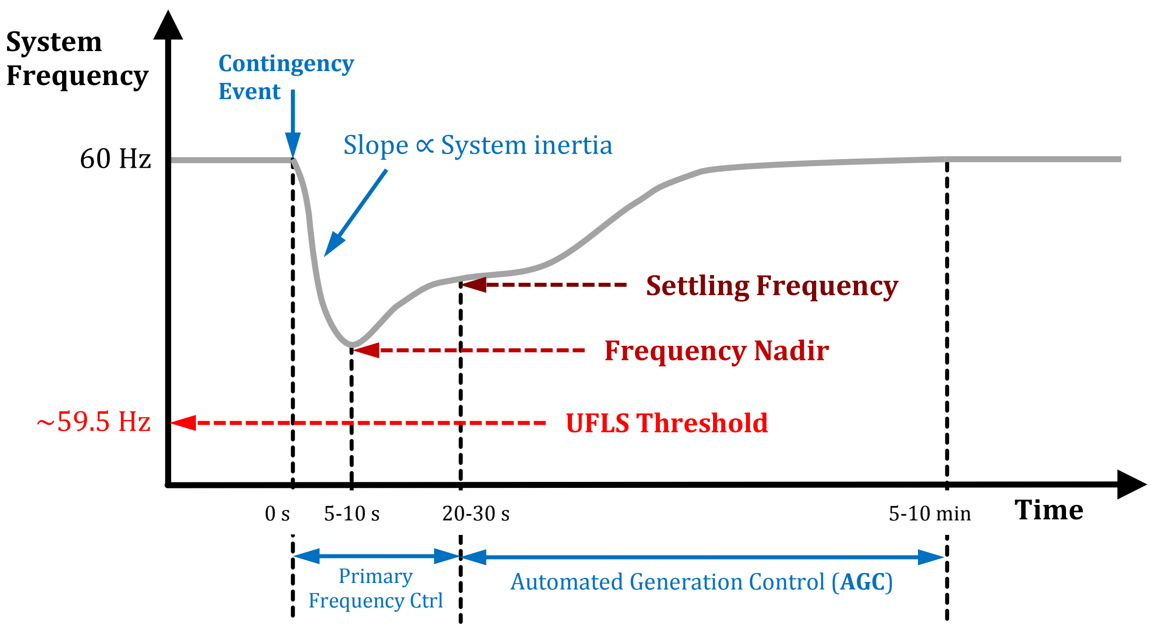

Figure 2: System frequency control following a loss-of-generation contingency event.

Deployment of VERs present operational challenges at the distribution level of the electric grid as well. Currently, the majority of distribution systems are predominantly radial networks (feeders) delivering grid-supplied power to customer's premises. With significant penetration of DERs distribution systems are facing a new demand to interconnect multiple feeders together in order to accept customer-generated power and be able to balance generation and demand on individual feeders with DERs available in surrounding feeders. In the future, distribution systems are likely to play two major roles; delivering power to or among customers and aggregating DERs to provide benefits to customers and the grid. The new structure and roles of distribution systems will require development of advanced distribution circuits and substations allowing bi-directional power flows, new protection schemes, and new control paradigms. Additionally,

[27] This issue is being addressed in new revisions of VER interconnection standards such as IEEE 1547. However, even with these changes, a large amount of legacy equipment will remain on the system that was compliant with older versions of the standard and could exhibit the mass-tripping behavior described here.
[28] N. Miller, M. Shao, S. Pajic, and R. D'Aquila, "Eastern Frequency Response Study," GE Energy, Tech. Rep. NREL/SR-5500-58077, May 2013.
[29] N. Miller, M. Shao, S. Pajic, and R. D'Aquila, "Eastern Frequency Response Study," GE Energy, Tech. Rep. NREL/SR-5500-58077, May 2013.
[30] R. Wiser and M. Bolinger, "Wind Technologies Market Report," http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf, 2011.

development of new technologies to enable DERs to provide Volt/VAR control resources are of great benefit to the grid given the importance of Volt/VAR optimization to achieving better asset utilization and improve distribution efficiency.[31] [32]

Grid Operating Reserves

Grid operators manage the variability of demand and generation on the system through reserves that are operated for diverse purposes across multiple timescales. Different amounts and types of operating reserves are secured in order to serve load reliably and keep the system frequency stable. Operating reserves (NREL report[33]) are defined as the real power capability that can be given or taken in an operating timeframe to assist in generation and load balance and frequency control. Systems also require reactive power reserves to provide voltage support. Finally, systems require certain targets for installed capacity that are often referred to as the planning reserve.

Operating reserves can be subdivided into five types: (1) frequency response reserves, (2) regulating reserves, (3) ramping reserves, (4) load following reserves, and (5) supplemental reserves, as summarized in Table 1 below. During normal system operation, regulating reserve (seconds) and load following reserve (minutes) are used. During contingencies, frequency response reserves (seconds) and supplemental reserves (minutes) are used for longer timescale events. Supplemental reserves are effectively used to replenish the faster responding reserves when these are insufficient to protect the system from the next event.

In addition to categorization by response time, reserves are classified by the physical capabilities needed of the responding participant. For instance, some reserves are required to be generating at part load to provide spinning reserve, others require Automatic Generation Control (AGC), and still others require portions of their reserve to be directly responsive to frequency deviations. According to NERC, the difference between spinning and non-spinning reserves is that spinning reserves must be synchronized to the system while non-spinning reserves are not necessarily synchronized.[34]

Both NERC and its sub-regions detail how much a balancing area of the grid will require of each type of operating reserve on its system.[35] For instance, the NERC BAL-002 standard requires that a balancing authority or reserve-sharing group maintain at least enough contingency reserve to cover the most severe single contingency. Regions typically require at least half of the contingency reserve to be spinning. Unlike contingency reserve, regulating reserves usually do not have explicit, pre-determined requirements on the amount of reserve that must be procured. Instead, balancing areas will maintain sufficient regulating reserves so that they meet their NERC Controlled Performance Standards (CPS1 and CPS2).

	Frequency Response Reserves	**Regulating Reserves**	**Ramping Reserves**	**Load Following Reserves**	**Supplemental Reserves**
Purpose of Reserve	Provide Initial Frequency Response to major disturbance	Maintain area control error due to random movement in a time frame faster than energy markets clear	Respond to events that occur over longer time frames than a contingency, but shorter than standard load following (e.g. wind	Maintain area control error and frequency due to non-random movements on a slower time scales than regulating reserves	Replace faster reserve to restore pre-event level reserve

[31] K. Mamandur and R. Chenoweth, "Optimal control of reactive power flow for improvements in voltage profiles and for real power loss minimization," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-100, no. 7, pp. 3185–3194, July 1981.
[32] Michael J. Krok and Sahika Genc, "A Coordinated Optimization Approach to Volt/VAr Control for Large Power Distribution Networks" American Control Conference, June 2011.
[33] E. Ela, M. Milligan, B. Kirby, "Operating Reserves and Variable Generation", National Renewable Energy Laboratories technical report NREL/TP-5500-51978, August 2011.
[34] "Average Operating Heat Rate for Selected Energy Sources," http://www.eia.gov/electricity/annual/html/epa_08_01.html, accessed: 2014-10-23.
[35] "How much electricity is lost in transmission and distribution in the United States?" http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3, accessed: 2014-10-23.

			forecast error, wind ramps)		
Other Names	Governor response, primary control	Frequency Control	Variable Generation event Reserve, forecast error reserve, balancing reserve		
Response Timescale	sec	sec	min-hrs	min	min-hrs
Spinning Reserve	✔	✔	✔	✔	✔
Non-Spinning Reserve			✔	✔	✔

Table 1: Summary of Reserve Types[36]

Increasing Grid Edge Functionality by Active Net-Load Control: The Potential for Greater use of Renewables

The challenges associated with centralized grid management by dispatching power generation as described above indicate the potential for direct control of DERs and load to be a complementary and beneficial strategy for affordable and reliable power delivery.

As noted above, generation and load must be balanced instantaneously and continuously to keep the power system stable and operating. Controllable reserves must be available to respond to variations in load and supply. From a reliability perspective, it does not matter if these reserves are provided by generation, demand response, or storage resources as long as they respond with the speed, accuracy, and magnitude that is required. At higher levels of renewables penetration, the available instantaneous renewable power output may surpass the system load, which makes curtailment inevitable unless there is flexibility available on the load side. The flexibility can be provided by energy storage or by scheduling system load to correlate its consumption with the availability of renewable energy.

While it is widely recognized that active participation from the load and DERs can improve dynamic behavior of the system, studies to date have generally considered only the correlation between technology features and dynamic recovery of frequency or voltage. Most notably, a recent study[37] that explored the technical and economic impacts of 30% renewable integration into the PJM interconnection assumed only traditional flexibility from the load (demand response).

To support high peak demand, utilities need to build very capital-intensive power plants and lines. Peak demand happens just a few times a year, and according to the Demand Response (DR) Smart Grid Coalition, 10%–20% of electricity costs in the United States are due to peak demand during only 100 hours of the year.[38] Current DR schemes are implemented with large and small commercial and residential customers, often through the use of dedicated control systems to shed loads in response to a request by a utility based on slow market price conditions (day-ahead or hour-ahead). Services (lights, machines, air conditioning) are reduced according to a pre-planned load prioritization scheme during the critical time frames. DR is a way for utilities to reduce the need for large capital expenditures by shedding some non-critical loads at peak times, and thus keep rates lower overall. However, there is a limit to such reductions because consumers will not tolerate too much real - or perceived - loss of quality of service. Thus, it is misleading to only look at the cost savings that DR can produce without also considering what the consumer forfeits in the process.

[36] Michael Milligan et al, NREL, "Operating Reserves and Wind Power Integration: An International Comparison", NREL/CP-5500-49019, October 2010

[37] GE Energy Management, "PJM Renewable Integration Study - Project Review (Task 3a)," http://www.pjm.com/~/media/committees-groups/committees/mic/20131028-impacts/20131028-pjm-renewable-integration-study.ashx, March 2014.

[38] E. Ela, M. Milligan, B. Kirby, "Operating Reserves and Variable Generation", National Renewable Energy Laboratories technical report NREL/TP-5500-51978, August 2011.

This program anticipates net-load functionality beyond the current load DR scenarios that could increase the benefits of DERs as an affordable, complementary technology for integrating renewables with the grid without loss of Quality of Service (QoS) to the consumer. Consumer QoS involve several factors including; electricity delivery reliability (based on SAIDI[39] and SAIFI[40]), cost of electricity, and load QoS to the consumer. Load QoS to consumer is inversely proportional to the magnitude of deviation from user-defined parameters (e.g. room temperature in the case of HVAC systems or water quality in the case of pool pumps) or mandatory system performance constraints (e.g. building ventilation requirements in the case of HVAC fans) caused by external load control mechanisms.[41] Several load types could likely be controlled with no net reduction in consumer quality of service or utility. While many flexible load resources can simply be switched off or cycled, other kinds of end-uses are capable of providing finer-grained control, such as reducing dimmable lighting levels or adjusting set-points on thermostats.[42] These flexible load resources can be directly controlled using automated DR to provide varying behaviors and response times.

Two major areas for improvement in operation of the power grid enabled by net-load flexibility are: the proactive shaping of load profiles over all relevant time horizons and geographical localities (home, neighborhood, city, and region); and leveraging the ability of load and DERs to provide dynamic response and positively contribute to dynamic system recovery, reducing the restrictions introduced by transmission and distribution network constraints. Shaping of load temporal profiles should include not only load shedding, but also aligning the flexible part of consumption with availability of renewable energy, directly contributing to increase in the grid efficiency, and CO_2 emission reduction.

C. PROGRAM OBJECTIVES

The overall objective of the NODES Program is to develop innovative and disruptive technologies to enable real-time management of T&D networks by large-scale active load control and system-wide coordination of DERs. Such technological advances would facilitate the utilization of net-load control to provide low-cost ancillary services to the electric grid at different time-scales and to improve grid operational reliability, efficiency, and resiliency.

NODES focuses on two major approaches to facilitate the integration net-load flexibility control in the electric grid's ancillary services.

The first approach is to alter the paradigm of grid operations by creating new functionality in various DERs that will provide net-load automated frequency response capability needed to overcome frequency stability limitations at higher renewable energy penetration levels.

The second approach is to develop advanced load shaping strategies, which make adjustments to load shapes over both short and long time horizons. This is a direct extension of traditional DR, which curtails the load to avoid using the most expensive peaking units. Short-term magnitude variation and time shifting of fast acting loads or distributed generation resources would facilitate large-scale coordinated control of net-load in order to provide fast acting synthetic regulation and contingency reserve services to the grid while minimally affecting customer quality of service. Long-term magnitude variation and time shifting of loads or DERs that are capable of responding to grid reserve signals within minutes, and maintaining the required net-load magnitude targets for few hours, would facilitate large-scale coordinated rescheduling of net-load in order to provide fast acting synthetic ramping reserve services to the grid.

Both approaches require building intelligence into distribution system components (distribution substations, distribution feeder circuits, transformers, and protection systems) to allow automatic reconfiguration and integration of DERs and to maintain acceptable voltage at all points along the feeder.

[39] System Average Interruption Duration Index (SAIDI)
[40] System Average Interruption Frequency Index (SAIFI)
[41] Yue Chen, Ana Busic, and Sean Meyn, "Individual Risk in Mean Field Control with Application to Automated Demand Response", IEEE Conference on Decision and Control, December 2014, Los Angeles, California, USA.
[42] David S. Watson et el. (LBNL), Karin Corfee el. (KEMA), "Fast Automated Demand Response to Enable the Integration of Renewable Resources", June 2012.

D. TECHNICAL CATEGORIES OF INTEREST

NODES is focused on supporting research and development of technologies that can enable reliable and affordable approaches to utilize net-load flexibility to provide operational reserve services to the grid, in one or more of the following three categories:

CATEGORY 1: Synthetic Frequency Response Reserves

A study analyzing year 2020 33% renewables scenario, conducted by CAISO, indicated that in times of low load and high renewable generation, as much as 60% of the energy production would come from VERs that displace the power output of conventional generation without providing inertial response.[43] Under such operating conditions, the study results showed that the frequency could drop below the acceptable UFLS threshold because the system did not have sufficient inertial response to be able to prevent frequency decline following the loss of a large conventional generator or transmission asset. Figure 3 below shows the effect of declining grid inertia within ERCOT interconnection from 2006 to 2010. This situation arises because renewable generators are not currently required to include automated frequency response capability. Therefore, they usually cannot increase their output power either because they are operated at maximum output or lack the control capability necessary to respond to system frequency regulation requirements. This decrease in available inertial response capacity leaves the system increasingly exposed to blackouts when generation or transmission outages occur.

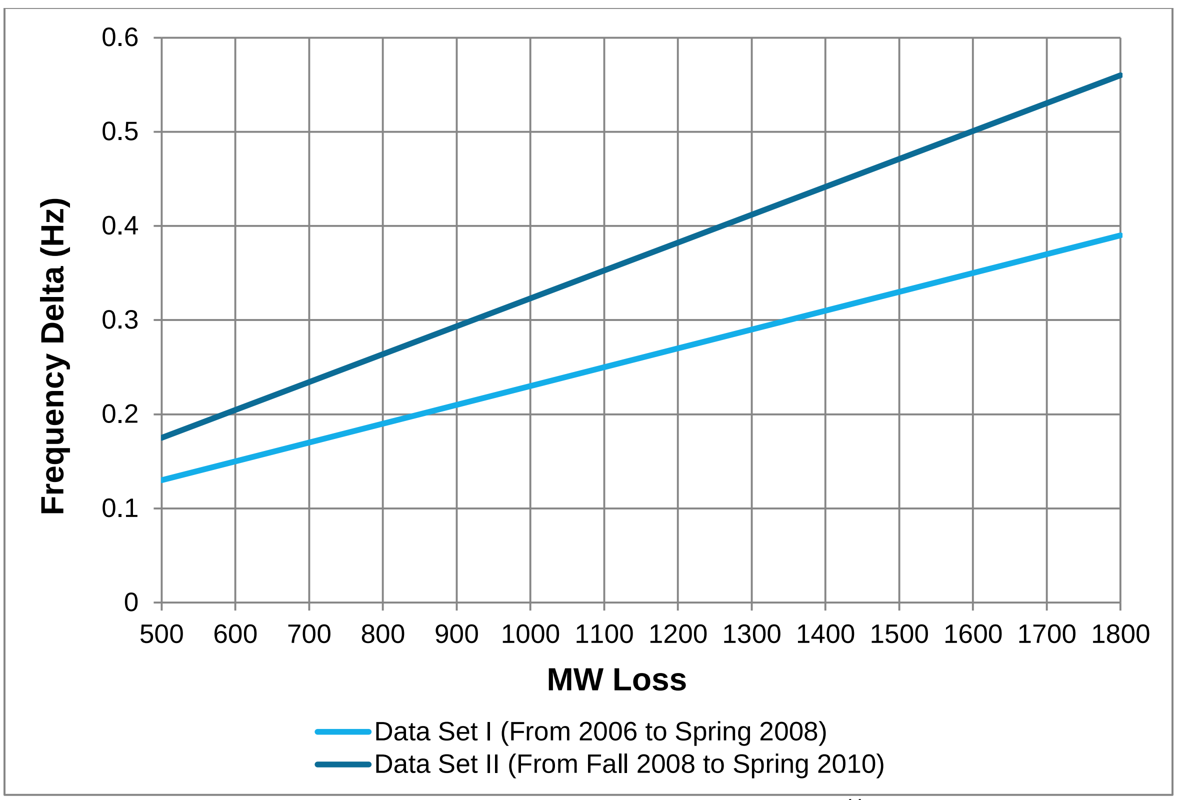

Figure 3: Declining grid inertia within ERCOT interconnection from 2006 to 2010.[44] System frequency decline is shown as a function of power loss in the system, with the red curve illustrating the loss of system inertia as a result of increased penetration of renewables.

[43] Nicholas W. Miller, Miaolei Shao, Sundar Venkataraman, "California ISO (CAISO) Frequency Response Study", GE Energy, Technical Report, November 2011.
[44] ERCOT Concept Paper, "Future Ancillary Services in ERCOT", Version 1.0, 2013

Approximately 44% degradation in frequency response has been observed for the case with about 30% of the generation participating in governor control.[45] One way to address this is to require renewable generators to operate at lower-than-maximum output and thus enable their participation in providing reserves; however, this would not be cost effective for renewable generation plants under current energy market rules. This pre-emptive curtailment has a financial penalty in that it reduces the utilized renewable energy. An alternative is to provide frequency response by energy storage and loads. The frequency events in the power system typically last less than 20 seconds; therefore, partial participation of loads in response to system frequency could be fully automated and would not cause noticeable changes in most settings.

This category focuses on the development of technologies to enable the net-load automated frequency response capability needed to overcome frequency stability limitations at higher VER penetration levels. If the dynamic load response can be provided using only the inherently available system frequency signal as input, the deployment of dynamically responsive load controls would not be contingent on the availability of a high-speed, high-cost communication channel to send state and control signals. Autonomous local control actions are more likely to result in faster frequency response time.

<u>Examples of potential technologies of interest for this category include, but are not limited to:</u>

- Decentralized control algorithms that:
  - Have a sufficiently fast response that they can provide a reliable replacement for generator inertial and governor response;
  - Are able to discern between events that require load response and those that do not, based on local measurements only;
  - Are sufficiently adaptive to remain effective as loads, generation and the system configuration change;
  - Are able to provide a coordinated response to system events under all loading conditions;
  - Properly coordinate a handoff from responsive loads back to generators during the frequency recovery period; and
  - Provide high levels of visibility and predictability to system operators.
- Centralized control algorithms that:
  - Integrate responsive load into grid inertial and governor response mechanisms, thereby reinforcing the system's own inertial response;
  - Are sufficiently adaptive to automatically remain effective as the system changes over time;
  - Minimize communication requirements and costs; and
  - Provide system operator visibility and predictability.
- Dynamic and robust load operational models (e.g., energy consumption patterns, responsiveness, and user utility).
- Techniques that account for the distribution network topology and variable constraints (e.g., line flow limits, transformer overload ratings) that can restrict the ability of connected loads or DERs to participate in a net-load management scheme. For example, a sudden adjustment in distribution-connected loads or DERs in response to a frequency event cannot result in distribution feeder voltage swinging beyond the acceptable range.
- Techniques that account for transmission network constraints that can be affected by active control of DERs.

<u>**Note: All technology examples provided in this FOA are only meant to illustrate principles, and they are *not* meant to prescribe or limit the technical approaches proposed under the NODES program.**</u>

CATEGORY 2: Synthetic Regulating Reserves

Significant integration of VERs into the grid requires the use of dispatchable, quick-ramping generators (spinning) that provide the regulating reserves necessary to smooth the variability and hedge against the uncertainty within a "balancing region." Spinning reserve units are required to be synchronized to the grid and able to rapidly increase or decrease their output on a short time scale (seconds to minutes, faster than energy markets react, but slower than AGC or inertial response) to provide contingency, regulation, and flexibility reserves. While operating in spinning reserve mode, these units are consuming fuel, producing emissions, and experiencing wear and tear, all while operating at very low power

[45] N. Miller, M. Shao, S. Pajic, and R. D'Aquila, "Eastern Frequency Response Study," GE Energy, Tech. Rep. NREL/SR-5500-58077, May 2013.

output levels at which the generators tend to be less efficient.[46] They also tend to be the more expensive units that could replace more cost effective resources because of the market reserve requirements. Additionally, generation based reserve units are only capable of providing "upward" reserves when they are operating at their minimum generation points. The need for "downward" reserves becomes more important at high renewable penetration when conventional thermal generators are operated at or near their minimum levels.[47]

This category focuses on developing enabling technologies that could facilitate large-scale coordinated control of net-load in order to provide fast acting synthetic regulating reserve services to the grid. Submissions to this category should focus on short-term magnitude variation and time shifting of fast acting loads or distributed generation resources that are capable of responding to grid reserve signals within seconds and ramp up/down to required magnitude targets within a few minutes.

"Synthetic Regulating Reserves" is the term being used in this FOA to describe the desired reserve service timing and magnitude characteristics. System operators may use a number of different types of reserves to meet the system need for this response. Additionally, different ISOs or RTOs use slightly different or overlapping definitions for the different types of operating and contingency reserves. Applications in this category could target technologies that can enable responsive loads or DERs to provide any type of reserve service that enables the system to handle short-term variability in the VERs' output.

<u>Examples of potential technologies of interest for this category include, but are not limited to:</u>

- Methods and architectures to optimally schedule and control local energy resources (flexible loads, distributed generation, storage) at the level of home or building based on user utility, weather forecast, and grid reserve and price signals.
- Methods and architectures to aggregate and coordinate controllable net-load resources at the distribution level and integration with transmission market and control structures effectively creating a "virtual power plant" from aggregated responsive loads.
- Real-time hierarchical or consensus-based distributed control methods, market models, and system architectures to actively manage very large number of loads to guarantee convergence while satisfying global (transmission), regional (distribution), and local operational constraints and objectives.
- Approaches that mitigate distribution system problems induced by variable net-load (voltage sags/surges, flicker, voltage rise …)
- Techniques that account for the distribution network topology and variable constraints (e.g., line flow limits, transformer overload ratings) which can restrict the ability of connected loads or DERs to participate in net-load control and aggregation schemes providing ancillary services to the bulk grid.
- Techniques that account for transmission network constraints that can be affected by active control of DERs.

<u>**Note: All technology examples provided in this FOA are only meant to illustrate principles, and they are *not* meant to prescribe or limit the technical approaches proposed under the NODES program.**</u>

CATEGORY 3: Synthetic Ramping Reserves

Some U.S. utilities, particularly in California, Hawaii and Texas, are beginning to experience a lack of sufficient ramping reserve generation due to high penetrations of VERs. "Ramping reserve" is usually considered to be generation reserve that is able to handle infrequent events that are more severe than those handled by regulating reserves, but less severe than contingency reserve.[48] Examples of situations in which VERs can cause events requiring ramping reserve would be:

- Sudden, unforeseen decrease in wind leads to a loss of wind generation and an error in net forecast load, or

[46] Marissa Hummon, Paul Denholm, Jennie Jorgenson, and David Palchak, National Renewable Energy Laboratory, "Fundamental Drivers of the Cost and Price of Operating Reserves", NREL/TP-6A20-58491, 2013.
[47] Marissa Hummon, Paul Denholm, Jennie Jorgenson, and David Palchak, National Renewable Energy Laboratory, "Fundamental Drivers of the Cost and Price of Operating Reserves", NREL/TP-6A20-58491, 2013.
[48] E. Ela, M. Milligan, B. Kirby, "Operating Reserves and Variable Generation", National Renewable Energy Laboratories technical report NREL/TP-5500-51978, August 2011.

- Late-day load pickup that is coincident with the decrease of PV output as the sun goes down. The combination of load pickup and loss of PV generation leads to what appears from the utility perspective to be an uptake in demand that increases as the PV penetration level rises (the “duck curves” in Figure 1).

These events may lead to large errors between actual and forecast net-load, meaning that a balancing authority may be required to call on contingency reserves or other standby generation to cover this load forecast error, leaving the system vulnerable to contingencies or other events that now cannot be covered by the generation used to supply the ramping reserve. Even if the event is predicted, and the likelihood of the event is known to be high, utilities must request additional reserve resources which is more expensive and increases emissions.

The main strategies available to mitigate this problem today are to add fast-ramping generation capacity, and as a last resort, initiate Conservation Voltage Regulation (CVR) or load shedding schemes.[49] None of these mitigation strategies is desirable. It is widely thought that responsive load can make a significant contribution to meeting this need, and responsive load would potentially have very significant cost advantages over either spinning or non-spinning ramping reserve. However, there is a significant challenge due to the fact that the load response will be required over a period of 30 min up to 2 hours. It is highly unlikely that any single flexible load could maintain a useful response over that entire time-period without disrupting service required by the end customer. Thus, there is a need for aggregation, coordination and dispatch algorithms that cause the widely dispersed aggregated load to have the desired ramp rate response characteristics and maintain them over the required time period (very much like the “virtual power plant” concept).

This category focuses on developing enabling technologies that would facilitate large-scale coordinated rescheduling of net-load in order to provide fast acting synthetic ramping reserve services to the grid. Projects in this category would focus on long-term magnitude variation and time shifting of loads or distributed generation resources that are capable of responding to grid reserve signals within minutes and maintain the required net-load magnitude targets for few hours.

“Synthetic Ramping Reserves” is the term being used in this FOA to describe the desired reserve service timing and magnitude characteristics. System operators may use a number of different types of reserves to meet the system need for this response. As previously mentioned, different ISOs or RTOs use slightly different or overlapping definitions for the different types of operating and contingency reserves. This is especially applicable in this category because “ramping reserve” is not yet a clearly defined term across the industry. Submissions to this category should target technologies that can enable responsive loads or DERs to provide any type of reserve service that enables a system with high penetrations of VERs to better follow high net-load ramp rates.

Examples of potential technologies of interest for this category include, but are not limited to:

- Quantitative assessments of the responsive load resource and its adequacy for providing slower, non-spinning type reserves. This includes quantification of load types’ flexibility capacity as well as real-time forecasting of load flexibility capabilities.
- Responsive load control and aggregation systems that are able to provide predictable and consistent synthetic ramping reserves over a period of few hours, without degrading the quality of service to the end user.
- Statistical modeling of the responsiveness of various populations of controlled loads in response to various reserve control signals.
- Utilization of data analytics and machine learning techniques to develop aggregated net-load behavior and response models from large-scale sensory measurements (thermostat data, smart meters, μPMUs …) and weather forecast.

Note: All technology examples provided in this FOA are only meant to illustrate principles, and they are *not* meant to prescribe or limit the technical approaches proposed under the NODES program.

[49] Irradiance and wind forecasting are also being developed to help in solving this problem, but these technologies are outside the scope of the present FOA.

E. TECHNICAL PERFORMANCE TARGETS

Proposed technical plans must show a well-justified, realistic potential for the technology to meet or exceed all of the Primary Technical Performance Targets described below by the end of the period of performance for the proposed project.

1. Primary Technical Performance Targets

The Primary Technical Performance Targets for the different project categories of this FOA are stated below, with time-sensitive performance metrics illustrated in Figure 4 below.

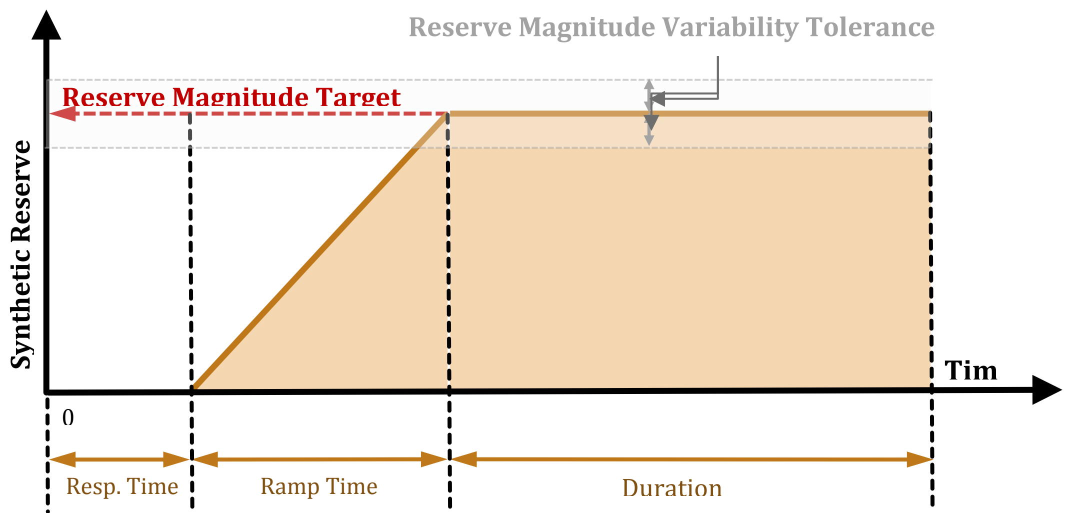

Figure 4: Schematic illustration of the timing performance metrics for synthetic reserves. Specific values for each timing metric are given for each of the three technical categories of interest: Synthetic Frequency Response Reserves, Synthetic Regulating Reserves, and Synthetic Ramping Reserves.

CATEGORY 1: Synthetic Frequency Response Reserves

ID	Performance Metric	Target Value
1.1	Initial Response Time	< 2 seconds
1.2	Reserve Magnitude Target (RMT, % of load)	> 2 %
1.3	Reserve Magnitude Variability Tolerance (RMVT)	< +/- 5%
1.4	Ramp Time	< 8 seconds
1.5	Duration	> 30 seconds
1.6	Availability	> 95 %
1.7	Cascaded Contingency Support	> 2

<u>Supplemental Explanation of Category 1 Performance Targets</u>

1.1 The *Initial Response Time* is the time between reception of a request for services (for centrally-controlled architectures) or initiation of the system-level event triggering a need for services (for architectures with distributed control) and the availability of the candidate system to provide the required reserve service.

1.2. The *Reserve Magnitude Target* (RMT) quantifies the amount of synthetic frequency regulation reserve provided to the grid through the aggregated active control of flexible load and VERs. It is expressed in terms of the percentage of system load within a given balancing area, at the time of the event triggering the need for this type of reserve service. The value of 2% is based on the magnitude expected to be required to make a significant positive contribution to the transient response of a typical balancing area.

1.3. The *Reserve Magnitude Variability Tolerance (RMVT)* quantifies the maximum tolerated deviation from the RMT after the initial ramping interval.

1.4 The *Ramp Time* is the time required to go from 0% activation to 100% of the RMT provided by the responsive load and VERs used in a candidate system.

1.5. *Duration* is the length of time over which the candidate system must be able to maintain RMT and stay within the tolerated variability envelope (deviation < RMVT) to satisfy system reserve services.

1.6. *Availability* is defined in this context in the same way as it is for generation resources; it is the fraction of time during which the aggregated responsive loads or DERs control system is able to provide its specified ancillary service to the grid.

1.7. The *Cascaded Contingency Support* parameter describes the number of cascaded contingencies (contingencies occurring one after another, spaced by no more than 15 seconds) that the candidate technology must be able to support. The purpose of this parameter is to ensure that a candidate technology providing Synthetic Inertial Response is prepared to assist the system in the event that a first contingency (e.g., loss of a major tie line) leads within a few seconds to a second contingency (e.g., mass tripping of VER or loss of other generation), which is a common occurrence that can lead to a cascade system failures. This parameter requires that the candidate technology be able to support no fewer than the specified number of contingency events involving the largest contingency elements within the balancing area, and should maintain effectiveness regardless of whether the contingencies involve loss of generation or load.

CATEGORY 2: Synthetic Regulating Reserves

ID	Performance Metric	Target Value
2.1	Initial Response Time	< 5 seconds
2.2	Reserve Magnitude Target (RMT, % of load)	> 5 %
2.3	Reserve Magnitude Variability Tolerance (RMVT)	< +/- 5%
2.4	Ramp Time	< 5 minutes
2.5	Duration	> 30 minutes
2.6	Availability	> 95 %

Supplemental Explanation of Category 2 Performance Targets

2.1 See 1.1 above.

2.2 See 1.2 above.

2.3. See 1.3 above.

2.4. See 1.4 above.

2.5. See 1.5 above. This value is based on historical data from balancing areas with high wind penetrations (ERCOT, SPP).

2.6. See 1.6 above.

CATEGORY 3: Synthetic Ramping Reserves

ID	Performance Metric	Target Value
3.1	Initial Response Time	< 10 minutes
3.2	Reserve Magnitude Target (RMT, % of load)	> 10 %
3.3	Reserve Magnitude Variability Tolerance (RMVT)	< +/- 5%
3.4	Ramp Time	< 30 minutes
3.5	Duration	> 3 hours
3.6	Availability	> 95 %
3.7	Recovery Time	< 4 hours

Supplemental Explanation of Category 3 Performance Targets

3.1 See 1.1 above.

3.2 See 1.2 above.

3.3. See 1.3 above.

3.4. See 1.4 above.

3.5. See 1.5 above. This value is based on worst-case values seen in balancing areas with heavy solar penetration (CAISO, HECO).

3.7 The *Recovery Time* is the time required by the candidate technology to become prepared to support a second ramping event, after having supported a first event. The value in the table is driven by experience with ramping events associated with wind farms. Ramping reserve to support high PV penetration levels (the “duck curve”) might be able to tolerate a longer recovery time as these events are anticipated at most twice per day, at sunup and sundown.

2. Additional Technical Objectives

The Additional Technical Objectives provided below apply to all technical categories of interest.

a. ***Validation***

- Quantitative validation of proposed solutions is required of all projects. Due to the wide range of different system designs that could potentially meet the technical performance targets described above, each team’s specific testing and evaluation plan is expected to be different.
- *Hardware-In-The-Loop Testing:* It is critical to test new control and aggregation schemes with a minimum of 100 actual hardware devices (representing 10s of customers/prosumers). This could take the form of testing diverse devices in a laboratory environment, a commercial building, a group of utility customers in a controlled experimental test platform, or a campus with controlled devices (e.g. electric vehicles charge stations, micro-grids.) In all cases, applicants should have a plan for demonstrating the effectiveness and convergence of their proposed solutions in this “hardware-in-the-loop” test environment.
- *Large-Scale Simulations:* Beyond testing the effectiveness of algorithms with actual hardware, large-scale, realistic simulations of the proposed flexible load and DERs control and aggregation schemes are also critically important for validating the robustness and scalability of the proposed solutions. During their projects, all NODES program teams are expected to prove the ability of their proposed solutions to control large-scale dynamical test systems. In order to ensure simulations are as realistic as possible, the datasets and models used for simulations should be provided by grid operators or utilities whenever possible.
- Applicants should provide a high level overview of their testing plan in the Concept Paper.

b. ***Renewable Penetration***

- Beyond testing the scalability of system concepts, large-scale simulations should also be used to quantify the role that the proposed control solutions can play in enabling the cost effective integration and management of intermittent, non-dispatchable renewable generation with penetrations of at least 50% on an energy basis (kWh of total). In these simulations, at least 15% of the renewable generation should be assumed to come from distributed generation resources. For example, project teams may choose to evaluate the avoided costs of additional balancing reserves for managing intermittency that would be necessary without the technologies involved in the project.

c. Consumer QoS

- Load/DERs control and aggregation technologies should demonstrate that they have minimal to no impact on the customer’s QoS from the load and the electric grid, including:
    - No negative impact on the reliability of electricity delivery to customers, as measured by indices such as SAIDI and SAIFI.
    - No increase in the cost of energy to customers by showing that they do not increase the monthly energy bill for all customers.
    - Minimal impact on the user QoS from the load by showing that they cause minimal deviation from user-defined load-utility parameters and/or mandatory system performance constraints. QoS performance parameters should be defined for each type of load under control and validation that the mean absolute percentage error (MAPE) in such parameters resulting from the introduction of the control approach is less than 2% should be provided.

d. ***Failsafe Designs***

- System control architectures should address or *resolve* the sensing, communications, computational, and actuation (ramp and dispatch) challenges for implementation in "real-time" markets under normal, stressed, and degraded conditions.
- Control solutions should be designed so that a failsafe operation occurs in the event of local or wide-area failure or attack.
- The control approach should demonstrate graceful degradation under major system failures or blackouts as well as gradual and stable recovery from such failures.

e. ***Cost Effectiveness***

- System control technologies must be cost effective, e.g., they must be at least competitive in cost with the incumbent reserves they seek to replace. The cost analysis should consider control systems' one-time fixed cost components, such as installation and commissioning cost, amortized over the expected system lifetime. It should also account for incremental operational cost to manage and maintain the system.

F. APPLICATIONS SPECIFICALLY NOT OF INTEREST

The following types of applications will be deemed nonresponsive and will not be reviewed or considered (see Section III.C.2 of the FOA):

- Applications that fall outside the technical parameters specified in Section I.E of the FOA
- Applications that have been submitted in response to other currently issued ARPA-E FOAs.
- Applications that are not scientifically distinct from applications submitted in response to other currently issued ARPA-E FOAs.
- Applications for basic research aimed solely at discovery and/or fundamental knowledge generation.
- Applications for large-scale demonstration projects of existing technologies.
- Applications for proposed technologies that represent incremental improvements to existing technologies.
- Applications for proposed technologies that are not based on sound scientific principles (e.g., violates a law of thermodynamics).
- Applications for proposed technologies that are not transformational, as described in Section I.A of the FOA.
- Applications for proposed technologies that do not have the potential to become disruptive in nature, as described in Section I.A of the FOA. Technologies must be scalable such that they could be disruptive with sufficient technical progress.
- Applications that are not scientifically distinct from existing funded activities supported elsewhere, including within the Department of Energy.
- Applications that propose any of the following:
    - Sensor development;
    - Computation hardware development;
    - Simulation only based validation of algorithms for Categories 1 and 2; or
    - Development of communication protocols or standards.

G. TECHNICAL GLOSSARY

AGC	Automatic Generation Control. Refers to the speed controller (governor) and field current controller (exciter) that control a generator's output real and reactive power.
Ancillary Services	Services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system
CAISO	California Independent System Operator.
CHP	Combined Heat and Power. A device that provides both electric energy and usable heat to a single or multiple buildings.
CVR	Conservation Voltage Regulation. CVR involves a deliberate reduction of the distribution voltage in an attempt to moderate demand.

DERs	Distributed Energy Resources. Similar to DG, except that DER specifically includes such things as energy storage or responsive loads that are not generation
DG	Distributed Generation. Typically refer to generation resources connected at the distribution level of the system.
Distribution system	The part of the electric grid traditionally used to distributed electric power (typically at <100kV) from the high-voltage transmission system to the end-user.
ERCOT	Electric Reliability Council of Texas.
Extra-high penetration of renewable energy	A level of penetration resulting in significant number of hours where instantaneous power output from variable renewable sources added to the power output from base-load nuclear fleet surpasses the instantaneous power consumption by the load.[50]
FERC	Federal Energy Regulatory Commission.
Frequency Nadir	Minimum frequency reached during a frequency excursion event. It is a direct measure of how close a system has come to interrupting the delivery of electricity to customers after a generation loss event.
ISO	Independent System Operator
LCOE	Levelized Cost of Energy
LOS	Level-of-Service
MAPE	Mean Absolute Percentage Error
NERC	North American Electricity Reliability Corporation.
Net-Load	The electric load minus the electricity production from VERS.
NODES	Network Optimized Distributed Energy Systems
QoS	Quality of Service
Quad	1 quadrillion (10^{15}) BTU
RMT	Reserve Magnitude Target
RMVT	Reserve Magnitude Variability Tolerance
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Settling Frequency	Refers to the point during a loss-of-generation disturbance when the frequency stabilizes following a frequency excursion. It represents the interconnected system frequency at the point after the frequency stabilizes due to governor action but before the contingent balancing authority takes corrective AGC action.
UFLS threshold	Under-frequency load shedding threshold.
VERs	Variable Energy Resources. These are generation sources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities.[51]

[50] GE Energy Consulting, Jovan Bebic', Gene Hinkle, Slobodan Matic', and William Schmitt, "Grid of the Future: Quantification of Benefits from Flexible Energy Resources in Scenarios With Extra-High Penetration of renewable Energy", Nov 2014.
[51] FERC Docket No. RM10-11-000; Order No. 764 "Integration of Variable Energy Resources" http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf