Appendix I

FINAL REPORT

Survey of Benchmarking of processes and tools for Power Grid Operators

A deliverable specified in the Research and Development Collaboration Agreement between National Grid ESO and Tapestry.

Contents

Glossary of Terms

Term	Definition
Contingency	The tripping (switching off) of a transmission line, transformer and/or generator caused by an unplanned or unexpected event on the power system.
Continuous thermal limit	A thermal limit based on continuous flow capability of a transmission facility. Also called normal rating. This is the facility rating under normal system conditions with no time limit.
Day-Ahead Market	Market transacting the day before the operating day to set schedules and commitments for Sale (delivery) of power and purchases (consumption) of power the following day, normally for a different quantity in each scheduling interval (e.g., schedules for each hour of the following day).
Day-ahead Scheduling	Process which begins by requiring market participants to nominate hourly demand requirements, generation schedules, flexible generation offers, flexible demand offers, reserve nominations and reserve offers for each hour of the next operating day. This process results in the initial operating plan which is then subject to detailed review and analysis by the grid operator to create the reliability-based operating plan for the upcoming operating day
Demand Response Resource	A customer that commits to alter their consumption of electricity in response to a price or control signal from the utility/grid operator in exchange for compensation or cost savings. Some Demand Response is contractually bound to certain performance standards and others are more voluntary response
Distributed Energy Resources (DERs)	Smaller scale distributed renewable resources, distributed storage (e.g., batteries, thermal storage, EV technologies) and alternative technologies (e.g., demand response controls, building energy management systems) at the distribution level. Often installed on the customer side of the utility metering point (behind-the-meter)
Emergency thermal limit	A thermal limit based on short term emergency power flow rating that can be used for limited time, typically 30 minutes or less. This rating is utilized in power system operations immediately after a contingency

Term	Definition
FLOR – Forward Looking Optimization Run	A security-constrained optimization model that simulates conditions for a forward-looking interval of time
LR – Lagrangian Relaxation	A constraint relaxation technique in mathematical optimization that approximates certain constraints (e.g., Integer constraints) to allow the program to solve a simpler problem which yields an approximate solution to original problem.
Linear programming	Mathematical optimization techniques designed to solve a system of linear equations to determine the optimal solution or best outcome. Formulated as a set of objective functions, subject to a series of constraints. The objective function is a mathematical statement of the overall objective (e.g., to minimize cost or to maximize benefit, etc.). the constraints are a set of inequality equations that define the feasibility region
Mixed Integer Programming	Mathematical optimization technique like linear programming except that some of the decision variables are constrained to be integers. The use of integer variables greatly expands the scope of useful optimization problems that can be solved because it accommodates discontinuities, but the MIP solution technique is more complicated than standard LP.
Operating Day	The contractual 24-hour period of power system operation that is covered by the contracts and obligations resulting from the day-ahead scheduling process
Pre-scheduling	The process of analyzing system requirements in advance of normal day-ahead scheduling to determine if inflexible generation resources are required to be committed to operate in advance due to inflexible operating parameters
Reliability Must Run Generator	A generation resource that is scheduled to operate to address transmission system security constraints or reserve requirements. Usually, the scheduling commitment occurs prior to normal day-ahead scheduling because of inflexible generator operating parameters.
SCADA	Supervisory Control and Data Acquisition, systems used to acquire data, monitor, and control various resources and devices

Term	Definition
Security Constrained Economic Dispatch (SCED)	An optimal power flow problem that includes transmission network security constraints as constraints on the optimization. Typically solved using linear programming solution techniques but more advanced SCED can also deploy MIP-based solvers
Security Constrained Unit Commitment (SCUC)	An optimal power flow problem that includes transmission network security constraints as constraints on the optimization and can handle integer variables, such as turning generation on or off. Typically solved using mixed-integer programming solution techniques
Stability Limits	The maximum power flow through a transmission line or set of transmission lines that can be sustained prior to a contingency event such that frequency excursions occurring after a contingency event will remain stable (e.g., frequency oscillations will be damped and will not sustain or grow over time)
Thermal constraints	Power flow limitations on transmission lines or transformers to limit the temperature attained due to current flow. Thermal limits on transmission lines are normally driven by sag (spacing) limit as line expands due to heating, Thermal limits can either be continuous flow limits or emergency flow limits.
Transmission system security constraints	Normal or contingency transmission line or transformer thermal constraints, voltage constraints and stability constraints
Voltage Constraints	Voltage constraints can be either magnitude constraints or voltage drop constraints. Voltage magnitude constraints are the high voltage and low voltage limitations to the magnitude of voltage at a substation. Voltage drop limits are limits on the change in voltage that occurs after a contingency event.

Introduction

The purpose of this document is to report on a desktop benchmarking analysis of best existing practices for power grid operators around the world in the processes and tools utilized to perform short-term resource scheduling and dispatch operations. This activity included a desktop review of existing practices as well as selected interviews with grid operators in Asia-Pacific, Europe, South America, and North America. Because of the sensitive nature of the operating details for power system infrastructure, this document does not provide attribution of specific details, it provides a general overview of practices and evaluates which practices seem to have the most promise as an initial starting point to manage increasing operational uncertainties as the industry moves through the energy transition. The analysis also includes commentary to assist in the understanding of what state-of-the art technology exists (or will be available) that could be beneficial to the National Grid ESO's Virtual Energy program and includes a section on emerging trends in regions with higher renewable resource penetrations and high-level review of any similar Digital Twin work in other regions.

Objective and Scope

The objective of this document is to satisfy the Benchmarking milestone of the Project plan specified in the Research and Development Collaboration agreement between National Grid ESO and Tapestry.

The scope of this evaluation focuses primarily on near-term power system operations which includes the period from day-ahead scheduling through to real-time dispatch operations. This survey was focused only on jurisdictions with some form of organized power market structure, with competitive suppliers and with separation of operation and/or ownership between transmission and generation. The scope includes high level evaluation of operational practices as well as tools and technologies utilized to perform the functions.

Executive Summary

As the energy transition continues, more distributed intermittent renewable resources, many with integrated storage, will continue to be connected to the grid, more distributed technologies such as smart home controls and EV charging will continue to alter consumer behavior. This trend will continue to create increasing uncertainty for grid operators in forecasting and predicting which hours of the operating day will be most challenging. As this uncertainty increases, traditional methods of predicting which operating periods are most challenging and which transmission boundaries are most limiting will become increasingly insufficient. Reliance past operating experience and judgment to make key scheduling and dispatch decisions is becoming less effective and becomes especially difficult with limited experienced staff resources.

Additional challenges and complexities are becoming more apparent, especially in jurisdictions with less automation. For example, in the past, when adjustments needed to be made to generation schedules to accommodate transmission limits or supply deviations, the operator only needed to change schedules of a few large generators. As large generators retire or become less dependable in responding, it is increasingly becoming necessary to adjust the schedules of many smaller generators or alternative resources instead. Obviously, managing larger numbers of small adjustments will at some point become unsustainable without automation. A summary of best practices that position grid operators to manage these trends in each operational process area is provided below.

Pre-scheduling

A best existing practice for predicting forward pre-scheduling requirements is to utilize an integrated model capable of simulating the dispatch over all 24 hours of the operating day with a security-constrained dispatch approach that models reserve requirements and transmission limits simultaneously. The most comprehensive of these integrated approaches, currently in use, employ detailed models of the transmission system with explicit contingency analysis to reflect operational criteria translated into a planning model context[1]. This approach is enabled by tools that are based on current state of the art technology such as mixed integer programming-based security-constrained unit commitment and dispatch algorithms. In the jurisdictions with more integrated and automated prescheduling analysis, the tools are offline planning versions of the mixed-integer programming-based security-constrained unit commitment and dispatch tools that

[1] Although the power flow model used in these forward scheduling studies is based on a simplified bus-branch representation of each substation rather than the fully detailed breaker-node substation model, the contingency definitions are modified to reflect the more accurate operational outage set based on actual breaker connectivity.

are used in dispatch operations. This more detailed forward pre-scheduling model that reflects more realistic operating contingencies and more granular evaluation of all potentially all operating hours is likely to become an industry standard during this period of transition to a more dynamic and distributed set of supply resources which may not follow traditional control signals. While the grid operators that are currently utilizing these more detailed and integrated approaches still face increasing challenges managing scheduling uncertainty, they appear to be much better positioned to make key pre-scheduling decisions with less staff commitment based on more accurate and more automated information flow.

Day-Ahead and Within-Day Scheduling

A best existing practice for reliability-based scheduling is to utilize an integrated model capable of simulating the dispatch over all 24 hours of the operating day with a security-constrained dispatch approach that models reserve requirements and transmission limits simultaneously. The most comprehensive of these integrated approaches utilize detailed models of the transmission system with explicit contingency analysis to reflect operational criteria translated into a planning model context[2]. As with the pre-scheduling analysis, this more automated scheduling approach is enabled by tools that are based on current state of the art technology such as mixed integer programming-based security-constrained unit commitment and dispatch algorithms. In the jurisdictions with more integrated and automated scheduling analysis, the tools are offline planning versions of the mixed-integer programming-based security-constrained unit commitment and dispatch tools that are used in dispatch operations. This more detailed scheduling model that reflects more realistic operating contingencies and more granular evaluation of all potentially all operating hours is likely to become an industry standard during this period of transition to a more dynamic and distributed set of supply resources which may not follow traditional control signals. While the grid operators that are currently utilizing these more detailed and integrated approaches still face increasing challenges managing scheduling uncertainty, they appear to be much better positioned to make key scheduling decisions with less staff commitment based on more accurate and more automated information flow.

It is important to note that all grid operators that were included in the survey reported increasing difficulty in forecasting Net demand due to changes in consumer behavior and increasing penetration of imbedded distributed energy resources and alternative technologies. While some grid operators have had success using sampling approaches to predict imbedded DER response, no

[2] Although the power flow model used in these forward scheduling studies is based on a simplified bus-branch representation of each substation rather than the fully detailed breaker-node substation model, the contingency definitions are modified to reflect the more accurate operational outage set based on actual breaker connectivity.

comprehensive existing best practice has emerged to accurately forecast net demand due to the rapidly changing circumstances.

Dispatch Operations

Upon review of the different approaches to dispatch operations, a highly automated approach with feedback and time coupling mechanisms appears to be a best existing practice for a variety of reasons. This type of approach is adaptable to changing circumstances and provides a platform to manage increasing operational uncertainty by producing scenario envelopes that provide operators with a selection of various projected trends from two hours before the operating hour through to real-time dispatch. These approaches utilize automation and feedback mechanisms to adjust the operating plan based on actual observed operational performance, key transmission line flow trajectories and net demand trajectories. This approach allows operators to focus on key operational parameters to make informed decisions. While these automated approaches still allow operators to make decisions based on their experience and judgement, they depend less on historical experience and provide more capability to visualize the current operational situation from a variety of perspectives.

Grid operators who have implemented this type of automated decision support tool report that operators have developed more confidence in dealing with uncertainty through scenario dispatch which has resulted in more optimal decision making and less need for conservative operation.

System Architecture

A dual primary system is a best existing practice since it protects against loss of critical dispatch system functionality which will become increasingly important as the energy transition continues to require higher levels of control and automation to assist grid operators in maintaining safe reliable grid operations. The added advantage of a dual primary system is that system upgrades and maintenance can be done on-line with much less risk of down time. As the energy transition continues these will be an increasing requirement for much more adaptable technology and for more rapid software and system enhancements much more often than in the past.

A highly modular open architecture approach that has been implemented in some jurisdictions appears to have more ability to adapt and add new functionality more rapidly than older, less modern approaches. Therefore, the open architecture, modular approach is a best existing practice.

Discussion of Power System Operation Approaches

Longer-Term Transmission and Generation Outage Scheduling

In all jurisdictions, there is a process to evaluate, coordinate and approve long-term transmission maintenance schedules, transmission construction outage schedules and generation maintenance outage schedules. In all jurisdictions, these processes are initially performed at least one year in advance and often are initiated several years in advance to accommodate longer term construction planning. The purpose of these forward scheduling processes is to analyze longer-term transmission and generation outages in advance to ensure that major transmission and generation outages are coordinated, and the outages are scheduled in a manner that is consistent with regional and local reliability standards and will allow the system to be operated reliably. In most regions, transmission utilities are required to nominate their outage schedules and the grid operator will confirm the coordinated transmission outage schedules. In many jurisdictions, especially those with some form of capacity payment mechanism, competitive generation owners are required to submit long-term outage requests and obtain approval from the grid operator. In many cases there are rules that require such outage schedules to avoid peak demand periods or other difficult operational situations. Once the forward outage schedules are approved, they are reviewed periodically through the year and adjusted as necessary to account for change requests and updated reliability requirements. As the operating period approaches, the coordinated outage plan is incorporated into near-term scheduling and operational engineering analysis.

The tools utilized to evaluate the outage schedules from a reliability criteria perspective are standard power system planning tools capable of performing steady state power flow analysis. In some cases, production costing type software is utilized to analyze the relative impact of outages on power production costs or power prices. However, in most jurisdictions' outage approvals are solely based on reliability standards and operational criteria.

Pre-scheduling (Week-ahead Scheduling)

While in every jurisdiction there are generally some procedures to perform seasonal and monthly operational studies to update forecasts, assess projected peak-period operational conditions, perform forward operational reliability studies, and potentially adjust some forward outage schedules, in most regions operational pre-scheduling analysis begins in earnest about one week to two days ahead of the operating day. The primary purpose of this forward pre-scheduling analysis is to assess if there is sufficient projected availability of generation with the startup flexibility needed to meet the following requirements for each hour of the operating day:

- Projected net demand
- Ensure sufficient availability for all categories of reserve
- Ensure transmission grid can be operated within voltage, thermal and stability constraints within operating criteria (e.g., voltage limits, n-1 contingency events, etc.)

This pre-scheduling analysis is necessary, in many jurisdictions, because the binding competitive offer period for generation is held one day in advance of the operating day and the normal economic scheduling of generation is performed day-ahead (usually less than 24 hours in advance). Certain generators may be inflexible and may require up to 48-hour notice to startup for a variety of reasons[3]. The week ahead pre-scheduling analysis is designed to capture these rare scheduling conflicts to ensure these resources can be scheduled ahead of time if necessary to avoid power shortages, reserve shortages and reliability violations. This type of scheduling is referred to as reliability must-run scheduling and the compensation for such resources is strictly controlled to address market power concerns.

In some jurisdictions, the analysis to evaluate the three criteria[4] is performed simultaneously using a fully integrated model that simulates security-constrained unit commitment and economic dispatch over each hour of the operating period using a detailed transmission model. In other jurisdictions, separate evaluations of net demand, reserve requirement and transmission constraints are performed and only for selected hours of the operating day using separate modeling approaches by separate teams. In these cases, the transmission model is sometimes based on simplifying approximations such as transmission interface or closed transmission boundary constraints that are utilized to represent normal or contingency-based transfer limitations on key transmission interfaces.

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[3] Older fossil generation generally requires a start time of more than 24 hours. In some jurisdictions, as fossil generation utilization rates decline some fossil plants require even longer notice, 72-96 hours in extreme cases, during certain seasons when they are partially mothballed to reduce maintenance costs. Nuclear generators also require long startup times.

[4] The most prevalent pre-scheduling criteria are net demand, reserve requirement for all reserve categories and Transmission constraints, including thermal, voltage and stability constraints

The analytical approach for these pre-scheduling activities to identify any necessary forward reliability must-run scheduling events varies by jurisdiction. The approaches are summarized in Table 1 below.

Table 1 – High level summary of Pre-scheduling approaches

Type	Modeling Approach	Analysis Approach	Time Periods Analyzed	Tools
Fully Integrated	Demand Requirement, Transmission constraints and Reserve requirements modeled simultaneously	Optimal scheduling of resources to satisfy all requirements in integrated model includes full transmission model detail	All 24 hours of the day	MIP-based unit commitment and dispatch simulation with integrated power flow software
Partially Integrated	Demand Requirement and Transmission constraints modeled simultaneously	Scheduling to meet demand and transmission constraints together, Reserve requirement not analyzed in detail	Projected Peak hour and a few selected other key projected transitional hours	LR-based Unit Commitment, LP-based economic dispatch, power flow software
Separate	Separate modeling for net demand analysis, transmission analysis and reserve analysis	All three analysis processes are done separately	Projected Peak hour and a few selected other key projected transitional hours	Spreadsheets to evaluate energy and reserve requirement needs and simplified power flow analysis for transmission interfaces

Generally, the pre-scheduling models are less detailed than day-ahead scheduling models and the focus of analysis tends to be on the projected peak operational periods because those periods have historically been the most challenging operational periods. However, in some jurisdictions as the energy transition is changing resource mix and demand characteristics, it is becoming increasingly difficult to project which periods of the day will be most challenging. Therefore, the industry trend appears to be moving toward adding additional detail to forward pre-scheduling modeling due to increasing projections of uncertainty.

As the transition to more renewable and distributed resources continues, most grid operators indicated they are experiencing increasing need to review the prescheduling timeframe in more detail because larger, fossil fueled generators are being operated less often and appear on a trajectory to retirement in many cases[5]. However, their retirement in some cases has been delayed because they are needed to maintain grid reliability and stability at certain times during this transitional period. Since many of these resources were originally designed to be operated nearly continuously, their ability to frequently start and stop operation was limited even when they were newer and well-maintained. As they become older and are less well maintained due to economic difficulties, their flexibility is even more limited. Since these resources have become expensive and have high emitting characteristics, many grid operators are motivated to make pre-scheduling studies more comprehensive to more accurately assess the need for operating these resources and to minimize their operation as much as possible while maintaining stability and security of the power grid.

Therefore, a best existing practice for predicting forward pre-scheduling requirements is to utilize an integrated model capable of simulating the dispatch over all 24 hours of the operating day with a security-constrained dispatch approach that models reserve requirements and transmission limits simultaneously. The most comprehensive of these integrated approaches, which are currently in use, utilize detailed models of the transmission system with explicit contingency analysis to reflect operational criteria translated into a planning model context[6]. This approach is enabled by tools that are based on current state of the art technology such as mixed integer programming-based security-constrained unit commitment and dispatch algorithms. In the jurisdictions with more integrated and automated prescheduling analysis, the tools are offline planning versions of the mixed-integer programming-based security-constrained unit commitment and dispatch tools that are used in dispatch operations. This more detailed forward pre-scheduling model that reflects more realistic operating contingencies and more granular evaluation of all potentially all operating hours is likely to become more of an industry standard during this period of transition to a more dynamic and

[5] In some cases, this retirement trajectory is estimated to be relatively quick, say 3 to 5 years, but in other cases it is a longer expected trajectory extending out 20 years.

[6] Although the power flow model used in these forward scheduling studies is based on a simplified bus-branch representation of each substation rather than the fully detailed breaker-node substation model, the contingency definitions are modified to reflect the more accurate operational outage set based on actual breaker connectivity.

distributed set of supply resources which may not follow traditional control signals. While the grid operators that are currently utilizing these more detailed and integrated approaches still face increasing challenges managing scheduling uncertainty, they appear to be much better positioned to make key pre-scheduling decisions with less staff commitment based on more accurate and more automated information flow.

Most grid operators expect that the need for such pre-scheduling analysis to determine if reliability must run resources are necessary will eventually diminish over time as the design of the power system and its operation is adapted to a more flexible, diverse, and distributed resource mix. However, many operators expect this transition to take several decades to accomplish.

Day-Ahead and Within-Day Scheduling

This period is defined as the period from 24 hours to four hours in advance of the real-time operations. Day-ahead scheduling processes and models are more detailed than pre-scheduling because the day-ahead scheduling process results in an actual operating plan for the next operating day which for details specific generation[7] operation and assignments for provision of energy and each category of reserve. The day-ahead operating plan also assigns generation operation to resolve any transmission security constraints including thermal, voltage and stability limitations.

To begin the development of an operating plan, in most jurisdictions market participants are required to nominate hourly demand requirements, generation schedules, flexible generation offers, flexible demand offers, reserve nominations and reserve offers for each hour of the next operating day into some form of day-ahead scheduling process. In most jurisdictions, grid scale renewable resources are required to enter nominations of forecast production and most have strong incentive for renewable resource operators to enter accurate information. In some jurisdictions, the scheduling is accomplished through a binding day-ahead market with financial settlement in which market participants submit generation schedules and offers, demand bids and reserve offers, and the market is ‘cleared’ or balanced by the market operator. In other jurisdictions the schedules are submitted by market participants who are responsible for balancing their supply and demand contracts and satisfying their reserve requirements. In either case, the resulting

[7] In some jurisdictions, reserve assignments for alternative resources such as demand response or batteries are also made during the day-ahead scheduling process and therefore they are included in the operating plan.

initial set of generation schedules and reserve assignments comprise the initial operating plan for the next operating day.

However, this initial operating plan is based on the market participants view of the upcoming operating day which is primarily driven by their own individual forecasts, commercial contracts, expectations of delivery constraints and risk management practices. Therefore, the initial operating plan is not a feasible plan that can be implemented because it does not necessarily comply with all reliability requirements such as reserve requirements and transmission security requirements.

Since the grid operator is responsible for operational reliability, the grid operator will analyze the initial operating plan to ensure it will satisfy all operational reliability obligations including the following:

- Projected net hourly demand forecast
- Updated hourly renewable resource supply forecast
- Ensure sufficient availability and make specific assignments for all categories of reserve
- Account for import/export schedules on interconnectors
- Ensure transmission grid can be operated within voltage, thermal and stability constraints within operating criteria (e.g., voltage limits, n-1 contingency events, stability limits, etc.)
- Account for any special operating conditions which may require implementation of conservative operating protocols

In all the jurisdictions that were analyzed, the demand forecast is based on forecast of the net demand[8] which is usually created as a total system, regional, and/or zonal forecast that is then distributed to the substation level using distribution factors that are based on near-term historical experience. These distribution factors are updated quite frequently in some jurisdictions and monthly/seasonally in others. Many jurisdictions are experiencing or expect to experience increasing uncertainty in prediction of net demand due to increasing penetration of distributed renewable resources, distributed storage, and alternative technologies at the distribution level. Some jurisdictions have had success in creating short-term predictive models of distributed behind-the-meter solar resource production by validating output from a representative sample of solar PV sites then upscaling the output to predict region wide performance using weather predictions, solar irradiance values etc. These types of representative sampling models have been used to predict regional DER performance with some success, but significant forecast inaccuracies have occurred due to unforeseen effects and changing customer behavior patterns. As

[8] The net demand forecast is the projected total demand less the projected DER production.

DER installations become more diverse with integrated storage and other technologies, a simple sampling approach has limited application. The increasingly diverse DER penetration is expected to create increasing uncertainty in locational net demand forecasting as some distribution feeders will experience more DER and the distribution utilities have not been able to easily track or predict such trends. While some entities have begun to explore pilot programs to better forecast DER production at the distribution level, there does not yet appear to be sufficient progress toward establishing a successful method to comprehensively predict net demand. While no specific best existing practice approach has emerged, a focus on approaches that use machine learning and artificial intelligence methods to better understand and predict DER and consumer behavior appears to be a promising development direction in this area.

Renewable supply resource forecasting obviously depends on accurate weather forecasting because for weather dependent renewable resources, like wind and solar power generation, the most important scheduling input comes from weather forecasting information. All jurisdictions surveyed have partnered with third party suppliers to provide enhanced or advanced weather forecasting and renewable resource production forecasting. Significant work has been done taking advantage of digital technologies such as artificial intelligence and big data to improve forecasting of renewable resource production in short-term and mid-term timeframes. Forecast improvement efforts are well documented and beyond the scope for this paper so this area will not be explored in detail here.

Reserve categories and deployment of reserves varies between jurisdictions and there is a significant difference in approach to reserve deployment between large interconnected systems and smaller isolated systems. However, for the purpose of this analysis, it is sufficient to describe the key features of the reserve scheduling and modeling processes and tools rather than exploring the details of different frequency control and reserve deployment approaches.

Although the terminology and specific response requirements vary across jurisdictions, it is possible to categorize reserves into the following three types.

Frequency Containment Reserves (FCR)[9] - This is the first response to frequency deviations; its purpose is to fine tune frequency and correct for small frequency changes due to short term fluctuations in supply and demand. FCR is usually an automated response within seconds to short term frequency imbalances.

[9] Also known as primary control reserves, primary reserves, frequency regulation, primary frequency control

Frequency Restoration Reserves (FRR)[10] - Purpose is to keep reserves available to respond to restore system frequency following a contingency event and larger frequency excursion. Response times are in the three-to-ten-minute range.

Replacement Reserves (RR)[11] - Additional energy that can be called upon to restore frequency restoration reserves in the event of a contingency event. Can be thought of as the 'headroom' that the operator has to re-balance the system after a significant event. Response times are in the ten-to-thirty-minute range.

The initial assignment of binding reserve obligation to generators and other technologies is done in the scheduling phase, based on forward contracts, or based on day-ahead market results, in some jurisdictions while in others the actual reserve assignments are not done until the dispatch phase of operations. In either case, reserve assignments are often modified during the dispatch phase of operations.

As the energy transition continues, many grid operators indicated they have looked to adapt their reserve categories, performance parameters and requirements to account for, and in some cases take advantage of, the changing supply mix. For example, some grid operators have adapted their FCR product to leverage the utilization of battery storage and to allow batteries to compete directly with other fast acting resources to provide such high-quality reserves. In other cases, grid operators have combined and simplified FRR-type reserves to accommodate demand-based response and take advantage of the benefit of expanding the set of choices available to operators to maintain vital reserve services. Several grid operators related quite positive experiences with adapting their reserve deployment processes to evaluate tradeoffs of utilizing conventional versus alternative resources for reserves which resulted in better overall performance, a more diverse supply mix and more equitable assignment of reserve obligations. In other, less advanced jurisdictions, market participants have been advocating for such comprehensive review and restructuring of reserve categories and deployment approaches to monetize the inherent flexibility in newer alternative resources. Therefore, a best practice appears to be undertaking a comprehensive review of the definition of reserve categories, performance parameters and requirements considering the transitioning resource mix. Also, many grid operators have reviewed and standardized reserve deployment and assignment practices to ensure the optimal resource mix is deployed to maintain stability and reliability of the power grid.

[10] Also known as secondary reserves, secondary frequency control, synchronized reserves

[11] Also known as tertiary reserves, operating reserves, scheduling reserves

In some jurisdictions, the analysis to evaluate the feasibility of the operating plan to satisfy the net energy forecast requirement and reserve assignments within all transmission security constraint criteria is performed simultaneously using an integrated model that simulates security-constrained unit commitment and economic dispatch over each hour of the operating period using a highly detailed transmission model. In other jurisdictions the evaluations of net energy forecast requirement, reserve assignments to meet reserve requirements and transmission modeling to ensure transmission security constraints are satisfied are done separately and only for selected hours of the operating day using separate modeling approaches by separate teams. In these cases, the transmission model is sometimes based on simplifying approximations such as transmission interface or transmission boundary constraints that are utilized to represent normal or contingency-based transfer limitations on key transmission interfaces.

The analytical approach for the reliability-based review of the initial operating plan also varies by jurisdiction. The approaches are summarized in Table 2 below.

Table 2 – High level summary of Reliability Scheduling approaches

Type	Modeling Approach	Analysis Approach	Time Periods Analyzed	Tools
Fully Integrated	Demand Requirement, Transmission constraints and Reserve requirements modeled simultaneously	Optimal scheduling of resources to satisfy all requirements in integrated model includes full transmission model detail	All 24 hours of the day	MIP-based unit commitment and dispatch simulation with integrated power flow software
Partially Integrated	Demand Requirement and Transmission constraints modeled simultaneously; Reserve model based on reserve eligible units only	Scheduling to satisfy demand and transmission constraints together, Reserve requirement analyzed separately	All 24 hours of the day	LR-based Unit Commitment, LP-based economic dispatch, power flow software
Separate	Separate modeling for net demand analysis, transmission	All three analysis processes are done separately	Projected Peak hour and a few selected	Simple LP for energy schedule, and reserve requirement

	analysis and reserve analysis		other key projected transitional hours	spreadsheet and simplified power flow analysis for transmission interfaces

As the energy transition continues, more distributed intermittent renewable resources, many with integrated storage, will continue to be connected to the grid, more distributed technologies such as smart home controls and EV charging will continue to alter consumer behavior. This trend will continue to create increasing uncertainty for grid operators in forecasting and predicting which hours of the operating day will be most challenging. As this uncertainty increases, traditional methods of predicting which operating periods are most challenging and/or which transmission boundaries are most limiting will become increasingly insufficient. Reliance past operating experience and judgment to make key scheduling decisions is becoming more challenging to perform effectively and becomes especially difficult with limited experienced staff resources.

Therefore, a best existing practice for reliability-based scheduling is to utilize an integrated model capable of simulating the dispatch over all 24 hours of the operating day with a security-constrained dispatch approach that models reserve requirements and transmission limits simultaneously. The most comprehensive of these integrated approaches utilize detailed models of the transmission system with explicit contingency analysis to reflect operational criteria translated into a planning model context[12]. As with the pre-scheduling analysis, this more automated scheduling approach is enabled by tools that are based on current state of the art technology such as mixed integer programming-based security-constrained unit commitment and dispatch algorithms. In the jurisdictions with more integrated and automated scheduling analysis, the tools are offline planning versions of the mixed-integer programming-based security-constrained unit commitment and dispatch tools that are used in dispatch operations. This more detailed scheduling model that reflects more realistic operating contingencies and more granular evaluation of all potentially all operating hours is likely to become more of an industry standard during this period of transition to a more dynamic and distributed set of supply resources which may not follow traditional control signals. While the grid operators that are currently utilizing these more detailed and

[12] Although the power flow model used in these forward scheduling studies is based on a simplified bus-branch representation of each substation rather than the fully detailed breaker-node substation model, the contingency definitions are modified to reflect the more accurate operational outage set based on actual breaker connectivity.

integrated approaches still face increasing challenges managing scheduling uncertainty, they appear to be much better positioned to make key scheduling decisions with less staff commitment based on more accurate and more automated information flow.

An additional advantage to using comprehensive and integrated modeling approaches is that the resulting scheduled operating plan will more accurately account for transmission and reserve requirements for each operating hour which reduces the likelihood of infeasible operating conditions due to errors or omissions in scheduling. Some grid operators have found that more manual and siloed approaches to scheduling of generation to address transmission security and reserve requirements had an increasing risk of missing key interactions between these requirements as scheduling became more complex which drove the need for integrated approaches to ensure that scheduling results in a feasible and reliable operating plan. Another driver that is commonly referenced is that integrated models helped reduce the need for adding operational staff to manage increasing uncertainties.

Dispatch Operations

This period is defined as the period from four hours ahead to real-time dispatch. In most jurisdictions, the operating plan moves from the scheduling phase into the dispatch phase approximately four hours ahead of real-time dispatch operation. In all jurisdictions, dispatch operations are segmented into to the following two general timeframes:

1. Forward looking analysis (4 hours to 15 minutes ahead of real-time)
2. Near-term balancing (30 minutes ahead up to real-time)

In some jurisdictions the dispatch operations are an incremental dispatch that essentially performs only incremental balancing around the binding generation schedules resulting from the day-ahead or forward scheduling/nomination process. In other jurisdictions, the dispatch operations are more comprehensive dispatch and balancing of supply and demand. All jurisdictions included in the survey allow self-scheduling of generation and all jurisdictions reported that renewable resources have no or very limited capability to respond to dispatch instructions. In a few jurisdictions, renewable resources have priority dispatch and most other regions require renewable resources to provide accurate forecasts or schedules of production and include some form of penalty or incentive so that such resources are encouraged to follow their forward nominated schedules.

Some form of forward-looking analysis is performed in all jurisdictions included in the survey. The overall goal of the forward-looking analysis is to continue to refine the operating plan to fine-tune the generation schedules, reserve assignments and transmission constraint control objectives and to adjust the plan as system conditions change, contingencies occur, or other unexpected events occur[13]. In all jurisdictions some form of scenario analysis is performed to evaluate potential trends of supply/demand balance, project impact of potential contingencies or other events on operating conditions and provide operators with suggested remedial actions in the event certain scenarios occur.

In some jurisdictions the forward-looking analysis and scenario evaluation is highly automated with feedback and time-coupling mechanisms designed to enhance the accuracy of information and solutions. In these highly automated models, power requirements, reserve assignments and transmission constraints are modeled simultaneously. Some of the automated modeling approaches include adaptive modeling of certain key inputs, such as transmission constraints and generation response predictions, which provides automated correction and cleansing of input data to improve accuracy of dispatch results. Since the analysis considers power balance, transmission constraints and reserve requirements simultaneously, the resulting scenario analysis and operator action suggestions incorporate the interaction of the various constraints and objectives so suggested actions are optimal and work to simplify the required operator decision making. This approach allows operators to focus on key operational decisions in a holistic manner.

In other jurisdictions, the forward-looking analysis is less automated and performed by separate teams of support engineers. In these less automated approaches, the support teams perform scenario analysis using off-line studies and develop various sets of operating instructions that real-time operators can use in the event contingencies occur. They also provide guidelines for operators to adjust based on larger deviations in supply/demand balance. However, in some cases these more manual approaches do not capture interactions between multiple transmission constraints or between transmission constraints and reserve objectives. The result is more reliance on the experience and judgment of operators to put all the pieces of information together to adjust the operating plan in a consistent manner.

While both approaches have been effective ways to perform reliable and cost-effective power system operations in the past, as the energy transition

[13] For example, unexpected events could be a transmission line tripping, a generator tripping, significant changes in regional RE resources performance, etc.

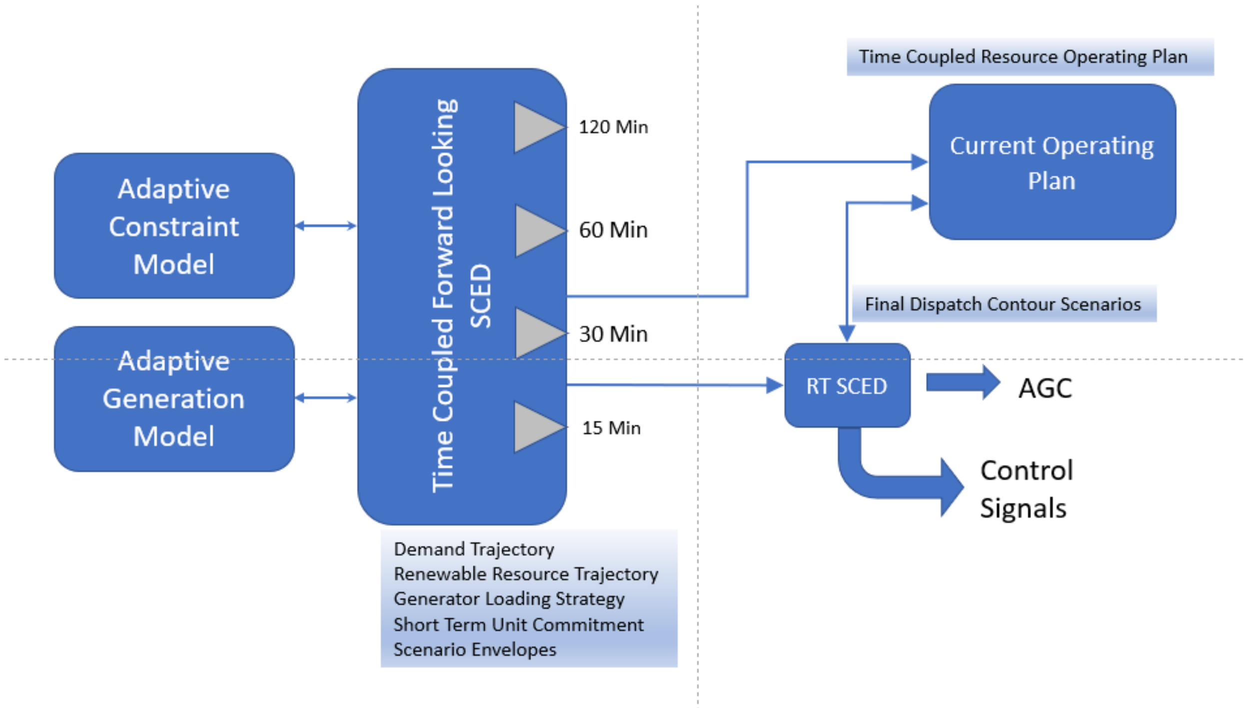
continues, reliance past operating experience and judgment to make key operational decisions is becoming more challenging.
Additional challenges are also becoming more apparent in jurisdictions with less automation. For example, in the past, when adjustments needed to be made to schedules to accommodate transmission limits or supply deviations, the operator only needed to change schedules of a few larger generators. As large generators retire or become less dependable in responding, it is increasingly becoming necessary to adjust the schedules of many smaller generators instead. Obviously, larger numbers of small adjustments will at some point become unsustainable without automation.

Therefore, upon review of the different approaches to dispatch operations, a highly automated approach with feedback and time coupling mechanisms appears to be a best existing practice for a variety of reasons. This type of approach is adaptable to changing circumstances and provides a platform to manage increasing operational uncertainty by producing scenario envelopes that provide operators with a selection of various projected trends from two hours out through to real-time dispatch. These approaches utilize automation and feedback mechanisms to adjust the operating plan based on actual observed operational performance, key transmission line flow trajectories and net demand trajectories. This approach allows operators to focus on key operational parameters to make informed decisions. While these automated approaches still allow operators to make decisions based on their experience and judgement, they depend less on historical experience and provide more capability to visualize the current operational situation from a variety of perspectives.

Grid operators who have implemented this type of automated decision support tool report that operators have developed more confidence in dealing with uncertainty through scenario dispatch which has resulted in more optimal decision making and less need for conservative operation. As the energy transition continues, grid operators are experiencing more operational situations they have not experienced in the past and the manual, less automated processes which depend more on operational experience will become less viable.

To explain the suggested best existing practice approach and tools in more detail, Figure 1 below provides a high-level overview of a highly automated process that has been implemented in several jurisdictions. A description of each of the components of this process as well as the overall operational and dispatch approach is provided below.

Figure 1. – Automated Dispatch Process with Feedback and Time-Coupling Mechanisms



Adaptive Constraint Model

This model evaluates current loading trends on key transmission interfaces and on transmission lines that are, or projected to be, at their operating limit within the current operating period[14]. The model tracks the transmission facility loading trend over the last few hours and evaluates the rate of change of actual and expected flow versus limit and suggests control strategies to mitigate the severity and cost of the managing constraint. It groups, ranks, and prioritizes active transmission constraints to develop a control strategy based on trajectory and interaction that minimizes the number of 'hard' limits enforced in the optimization phase to make constraint control more effective and reduce burden on the transmission operator. For voltage and stability constraints, on-line AC power flow analysis is used to provide updated linearized pre-contingency flow limit surrogates that are linearized at the current operating point to increase accuracy. Since these models are highly specialized and were designed to evaluate unique parameters of the regional transmission grid, they were developed as in-house solutions by the grid operators.

Adaptive Generator Model

[14] This includes thermal limits, PV characteristics, voltage limits and stability limits

This model evaluates the current generation performance versus its committed or projected performance. Also evaluates each generator's operational history which is used to predict actual response to dispatch instructions and to certain conditions such as weather and operating circumstances. The model creates a probabilistic response model for each generator and replaces the need for operators to correct bad input data. The model creates updated response rates, ramp rates, and forecast output for the near-term operating period which creates a more realistic set of input data for use in the development of optimized dispatch trajectories. The model can also be used to track forecast versus actual production for renewable resources and suggest operational adjustments to compensate for sustained or large forecast errors of renewable resource production. Since these models are highly specialized and were designed to evaluate unique parameters of the local generation they were developed as in-house solutions by the grid operators.

Time-Coupled, Forward-Looking Security-Constrained Economic Dispatch

This module is a family of optimization engines that utilize MIP-based algorithms to solve a series of security-constrained economic dispatch problems[15], that also co-optimize energy and reserve dispatch[16], for various time periods leading up to the real-time dispatch. The time period covered by each Forward Looking Optimization Run (FLOR) and their connectivity relationship can vary depending on operational conditions and resource mix. The time period designation represents the number of minutes in advance of real-time operation. For the example shown in Figure 1, time periods of the FLOR are set at 15, 30, 60 and 120, minutes before real-time operations.

Obviously dispatch operations are continuous, but in most jurisdictions market participants' offers, transactions and/or schedules are changed on a daily cycle which can create an artificial boundary called the start of the operating day. Therefore, we begin the description of SCED operation at the start of the operating day. At the beginning of each operating day, the FLOR15 establishes the initial trajectory dispatch for the period from current time to 15 minutes ahead by calculating the projected operating point for each resource 15 minutes forward. The FLOR30 calculates trajectory dispatch for the period from the FLOR15 result to 30 minutes ahead by calculating the projected operating point for each resource 30 minutes forward. FLOR60 and FLOR120 calculate the projected operating points for 60 and 120 minutes forward respectively. This series of forward-looking optimization runs creates a trajectory for dispatch over the next 120 minutes that

[15] Some of the forward-looking economic dispatch problems also require commitment of short lead time resources (e.g., peaking generators or demand response) so the optimization engines are capable of handling integer variables.

[16] the co-optimization of energy and reserves means that there are multiple objective functions to minimize the cost of energy production as well as to minimize cost of provision of all categories of reserve simultaneously subject to all energy, reserve, and transmission constraints

are time-coupled because each calculated operating point is based on the projection of the previously calculated operating point. Since the SCED engines respect all constraints including generation ramp constraints[17], transmission limitations[18], etc., the resulting dispatch trajectory represents a realistic dispatch envelope over the next two hours of operation. This dispatch trajectory is then updated 15 minutes later when the next set of FLOR15,30,60,120 executes. This forward-looking dispatch system provides automatically updated forward dispatch trajectories every 15 minutes to assist operators in making short term resource commitment, reserve assignment adjustments and dispatch decisions to keep the current operating plan accurate and realistic.

Another benefit of time-coupled optimization and scheduling capability is that it provides a platform to manage limited energy resources because the time coupling provides a linkage to evaluate deployment of limited energy resources over time. Such an approach can be used to evaluate the tradeoffs of deploying energy limited resources between current and future dispatch periods to optimize utilization. Time coupling can also be deployed to schedule recharging of storage devices as part of the balancing to utilize the capability of such resources more fully. These optimization models were developed based on standardized optimization solvers such as CPLEX, Gurobi and others.

Real-time SCED

The real-time SCED module is an optimization engine that utilizes a MIP-based algorithm to solve the current security-constrained economic dispatch problem that co-optimizes energy and reserve dispatch while respecting transmission security constraints. This module is executed every 5 minutes to create the final set of dispatch instructions for generation and alternative resources which are set out automatically upon approval of the RT SCED operator.

The module is also capable of creating multiple final dispatch contour scenarios which provide the system operator with the flexibility to choose which scenario is best to satisfy current system control requirements while enforcing all security and reserve constraints to present the operator with a consistent, simultaneously feasible solution that also allows operator discretion and judgement. The operator can request three dispatch contour scenario alternatives based on net desired change in supply/demand balance. The best way to illustrate this functionality is through the following example

[17] The ramp limits that are enforced are generally the adapted, realistic, ramp limits calculated by the adaptive generation model unless overridden by the operator

[18] The transmission limits enforced are the adapted, more accurate transmission limits calculated by the adaptive transmission model unless overridden by the operator

- Example 1 – Suppose the current forecasted net change in system supply/demand balance requirement is forecast to be +100 MW over the next 10 minutes, the operator could enter a set of balanced scenario requests like +200, +100 and 0 and then choose the resulting solution that best fits the current conditions based on their judgement.
- Example 2 – Suppose the same supply/demand balance forecast of +100 MW as in Example 1, but the operator believes the demand forecast is too high by 500 MW, so net change should be -400 MW, they can then enter scenarios at -200, -400, -500, view resulting solutions and choose the one that best fits the current conditions based on their judgement.
- Example 3 – Suppose a high ramp period where the supply/demand balance forecast requirement is +600 MW in the next 10 minutes, but operator is concerned that generators are slow to ramp they can then enter scenarios at +600, +800, +900, view resulting solutions and choose the one that best fits the current conditions based on their judgement

This approach to providing system operators with the ability to request scenarios based on key parameters and then select the resulting comprehensive solution based on their judgement appears to be a best existing practice which allows computer-assisted decision support. While the solutions that are currently deployed by grid operators focus just on power balance scenarios, this approach could be extended to other scenarios like line-tripping or other events. This approach uses automation to improve awareness and present the operator with information to make key decisions. This approach appears to be a good way to assist operators in making decisions without attempting to over-automate.

An additional benefit to this computer-assisted approach to operator decision making is it creates the ability to record and evaluate operator override decisions that can later be utilized in operator training scenarios. This type of automatic recording and evaluation system has been implemented in at least one jurisdiction and is being utilized to analyze and improve dispatch tool and operator performance over time.

These optimization models were developed based on standardized optimization solvers such as CPLEX, Gurobi and others. In practice, the largest of these optimization models that are being solved to support dispatch operations are more than 10,000 busses, and over 1000 constraints and control variables. These models are being utilized by grid operators in the US to implement real-time operations and solve in 1 to 5 minutes depending on the mode of operation[19].

[19] In real-time SCED mode execution times are less than 2 minutes, look-ahead mode can be as long as five minutes

Dispatch Signals and Instructions

The delivery of dispatch control signals and instructions varies by jurisdiction. In some jurisdictions dispatch instructions are sent automatically upon operator approval to generators and other resources[20]. In other jurisdictions electronic instructions are sent but through a more manual, individual approval process and in still other jurisdictions, instructions are sent via a combination of electronic signals, phone calls and other communication methods using a less automated or manual process.

As the energy transition continues, larger generators will retire and be replaced by many smaller, more distributed resources. Therefore, a best existing practice will be to move toward more automated dispatch instruction delivery because it will be increasingly difficult for system operators in less automated jurisdictions to continue to review and send individual instructions.

In some jurisdictions, the electronic dispatch signals are sent directly from the grid operator's control center to each generator, but more commonly, the electronic signals are sent from the grid operator control room to the generation owner's control center which then distributes them to individual generators that they own or control.

Most jurisdictions utilize Automatic Generation Control (AGC) to keep frequency within established bandwidth. AGC is a system for automatically adjusting the power output of generators in response to changes in system frequency. Reliable and stable power grid operations require that load and generation are closely balanced minute by minute. If more power is being generated than consumed, all generators in the system begin to speed up which increases system frequency. Conversely, if less power is generated than consumed the generators slow down which decreases system frequency. The AGC system senses such system frequency changes and automatically changes generation output to keep load and generation in balance and frequency stable.

Demand Response and Distributed Resources

In many jurisdictions demand response resources and other distributed resources have become or are becoming an important part of the dispatch process. Demand resources, as small as 0.1 MW in some jurisdictions, are participating directly in economic dispatch and power markets. Grid scale and smaller distributed storage devices (e.g., batteries) are providing frequency regulation, other reserve services

[20] In some jurisdictions, alternative resources such as demand response or grid-scale battery storage are included in dispatch

and economic response to market pricing and dispatch instructions. Utilization of these small, distributed resources for dispatch response and system control has required innovations in communications and control technologies to adapt dispatch systems, which were designed based on large central station generation, to accommodate and leverage smaller controllable resources. Traditional SCADA systems with dedicated communication links are too expensive for small resources. Some jurisdictions have deployed cellular technology-based and/or internet-based SCADA systems as a lower cost way to communicate with distributed resources. These approaches have been used in several jurisdictions to improve operational visibility and control for small, distributed alternative resources.

Obviously, creating communication paths into power grid energy management systems must be carefully controlled to address information security and cybersecurity concerns. The jurisdictions that have implemented cellular and internet-based communication paths have addressed these security concerns in a variety of ways. Discussion of security details is beyond the scope of this document.

Primary and Backup Dispatch Systems

Since real-time dispatch systems are mission critical to maintaining economic, secure, and reliable power system operations, such systems must be highly available and emergency backup systems are necessary to ensure continuity of operations. The approach to designing and maintaining highly available primary and backup dispatch systems varies by jurisdiction. The high-level design approaches are summarized in Table 3 below

Table 3 – High-level design approaches for primary and backup system architecture

Description	Backup System state	Time to switch to Backup	Backup Functionality	Upgrade / Maintenance
Dual Primary	Instantaneous Backup	Instantaneous	Same as Primary	On-line, no outage required
Primary with Failover	Failover to Backup	30 minutes to 180 minutes	Same or Similar to Primary	Failover Required
Primary with limited function backup	Older Technology or Manual System Backup	Varies	Significantly Reduced from Primary	Outage required

In some jurisdictions, dual primary dispatch systems are implemented which are operated as parallel but separated systems are implemented and both execute in 'production' mode. One of these systems is designated as primary and the other is designated as secondary or backup. In other jurisdictions, only a single primary system is operational and the backup system, based on similar technology is kept in a warm but offline state and can be started through an automated 'failover' process if the primary system fails or needs to be taken down for upgrades or maintenance. Some jurisdictions only operate a single functional primary system, and the backup system is based on older technology or manual procedures.

Obviously, the dual primary system is a best existing practice since it protects against loss of critical dispatch system functionality which will become increasingly important as the energy transition continues to require higher levels of control and automation to assist grid operators in maintaining safe reliable grid operations. The added advantage of a dual primary system is that system upgrades and maintenance can be done on-line with much less risk of down time. As the energy transition continues these will be an increasing requirement for much more adaptable technology and for more rapid software and system enhancements much more often than in the past.

System Architecture

The architecture of the energy management system, market management systems and distribution management systems drive the scalability and flexibility characteristics of the overall dispatch platform. As shown in Table 4 below, there is a wide diversity of approaches to system architecture.

Table 4 – Architectural approaches for Energy Management systems

Description	Approach	Adaptability Characteristic
Highly Modular	Highly Modular, Open Architecture utilizing Enterprise service bus and APIs as integration platform. Applications are built as modules connected through and orchestrated by the enterprise service bus	Highly flexible and scalable system modular components. Applications easily added or modified
Proprietary Integration	Large interconnected system using proprietary platform. Applications tightly integrated into proprietary platform	Highly integrated system limited flexibility. Application Enhancements or

		additions often require total system upgrade
Disparate Systems	Collection of disparate systems using different technologies with limited integration between systems.	Varies but generally limited scalability and flexibility

Some jurisdictions have implemented highly modular approaches which utilize, and open architecture built on the concept of an enterprise service bus which provides an adaptable platform to connect and orchestrate functional applications through APIs. Other jurisdictions have more traditional, highly integrated systems based on proprietary EMS platforms using a proprietary technology platform that is not modular. Still other jurisdictions have more disparate systems that have generally evolved over time using different technologies.

As discussed previously, the energy transition is causing rapid changes in the power industry with rapid deployment of renewable energy technologies, distributed resources and other alternative technologies which require much more adaptable systems to manage power system operations. Therefore, the highly modular open architecture approach that has been implemented in some jurisdictions appears to have more ability to adapt and add new functionality more rapidly than older, less modern approaches. Therefore, the open architecture, modular approach is a best existing practice.

Emerging Trends in Regions with High Renewable Resource Penetration and Digital Twin Activity

Grid operators in regions with higher and growing renewable resource penetrations have faced significant challenges in keeping up with the speed of transition. The challenges that grid operators most often highlighted are as follows:

- Loss of inertia as large, legacy resources are de-commissioned
- Increasing concern and difficulty in keeping frequency and voltage control within criteria
- Electricity supply fleet is less controllable and is increasingly weather dependent
- Lack of visibility for distributed resources and all renewable resources in some cases
- Net demand is much less predictable due to DERs and changing consumer behaviors

Flow reversals on sub-transmission and distribution lines has required operational changed and re-engineering in some cases

Experiencing unforeseen operational challenges more frequently with inadequate information which causes conservative operation more frequently

Lack of knowledge, experience and confidence with how inverter-based technologies will respond to system disturbances

To address these emerging issues, grid operators are adjusting operational practices and upgrading operational tools and in some cases are advocating for regulatory changes and market design changes to help address the challenges. The set of initiatives that is being considered varies significantly by jurisdiction. Some of the most referenced initiatives are as follows[21]:

Improve generation interconnection standards and make them equitable across all resources

implement DER interconnection standards

Regulatory and/or market rule changes to incent renewable resources to provide accurate production forecasts and match actual production to forecast when necessary.

Improve metering and data collection for distributed resources,

Improve net demand forecasting using advanced techniques and algorithms that consider DER, consumer behavior and other factors

Address data and information gap at transmission distribution interface encourage or require coordination between transmission and distribution operators

Move markets closer to real-time and implement five-minute settlements to incent fats and accurate response to price signals

Review of reserve products and markets and revised to include and incent DER participation

Add fast frequency response and ramping products

Accommodate and encourage demand-side and distributed storage participation in all markets

Integrate congestion management with energy balance and reserve deployment

Evaluate capacity mechanism for system security and reliability services

Significantly improve and automate grid operational tools and models to improve operator situational awareness and decision making

Aspirational goal to create digital twin model of entire system (supply, demand, transmission, and distribution)

[21] A few of these initiatives have been implemented others are either planned or being considered. Grid operators indicate that a number of these initiatives may require market rule and/or regulatory changes

In regions with a goal to develop digital twin models, the intent is to develop the modeling capability incrementally with the long-term goal resulting in a comprehensive model. The starting point is generally focused on improving metering, information gathering and forecasting at the distribution level. This improved data modeling will then be enhanced by applying advanced digital technologies such as machine learning, artificial intelligence, and big data to improve forecasting. With improved data models, simulation capability can then begin followed by optimization and orchestration approaches. With a strong digital model foundation, the simulation and optimization modeling can be expanded to perform scenario analysis and improve operational resiliency of the models and ultimately of grid operation.