Smart Dispatch of Generation Resources for Restructured Electric Power Systems

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*Abstract--***This paper addresses the vision of a new generation dispatch system for restructured power systems. As distributed generation, demand response and renewable energy resources become significant portions of overall system installed capacity, a better system dispatch tool for system control centers is required in order to cope with the increasing amount of uncertainties being introduced by the new resources. A Smart Dispatch (SD) framework for regional transmission organizations and transmission system operators to manage large power grids is proposed. In particular, the ability of the new dispatch system to provide a better holistic and forward-looking view of system conditions and generation patterns will be discussed in detail. Such features are deemed critical for the success of efficient system operations in the future.**

Index Terms—**Economic dispatch, system security, system operations, electricity market, smart grid, generation control**

I. INTRODUCTION

THE restructured electric power industry has brought new challenges and concerns for the secured operation of stressed power systems. Energy systems whether in developed or emerging economies are undergoing fundamental changes due to the emphasis of low carbon energy mix and the demand responsiveness. This will lead to a profound transition from the current centralized infrastructure towards the massive introduction of distributed generation, responsive and controllable demand and active network management throughout the system. At the same time regulators and market participants appetite for market liquidity and transparency naturally drives towards larger trading areas as well as new incentive for end users to consume their energy smartly.

Unlike conventional generation resources, outputs of many of the renewable resources do not follow traditional generation/load correlation but have strong dependencies on weather conditions or demand for heat, which from a system prospective is posing new challenges associated with the monitoring and controllability of the demand-supply balance.

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As distributed generations, demand response and renewable energy resources become significant portions of overall system installed capacity, a smarter dispatch system for generation resources is required to cope with the new uncertainties being introduced by the new resources. Regional transmission organizations (RTOs) and transmission system operators (TSOs) managing large geographical regions of resources need better tools to support operator's decision-making. The ability of the new dispatch system to provide a better predictive, forward-looking holistic view of system conditions and generation patterns is deemed critical for the success of efficient system operations.

Around the world very large power grid operators like PJM, Midwest ISO or North China Grid are fundamentally reliant on some generation-dispatching systems to optimally dispatch generation resources to serve the native load in large geographical regions [1]. Facing the challenges posed by the smart grid, RTOs/TSOs are in the process of designing the next generation of dispatch systems with broader and higher capability to handle the uncertainties ever before. For example, the limited dispatchability and intermittent nature of wind and solar generation could require grid operators to supply additional ancillary services needed to maintain reliability and operational requirements. The new dispatch system will need to somehow economically manage rapid changes in load, generation, interchange and transmission security constraints simultaneously on a real-time and near real-time basis. It is also expected that the system will flexibly incorporate various power forecast data sources including demand forecast and renewable generation forecast. A new time-coupled dynamic dispatch engine will provide a desired dispatch profile for any specified time frame. The scheduling solutions of different time frames addressing different system scenarios are consolidated to form a continuum of comprehensive operating plan (COP). COP provides operators with a holistic forward-looking view and continually updated view of trends and dynamics of generation profile and system conditions hours ahead of real-time.

The rest of the paper will be presented as follows. An overview of the evolution of economic dispatch is given in Section II. Section III discusses the functional framework and the vision for Smart Dispatch from a system operator perspective. Section IV describes the newly proposed dispatch system called generation control application (GCA) which is a key part of the overall smart dispatch vision. Conclusions are drawn in Section V.

II. The Evolution of Economic Dispatch

Economic dispatch is about the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities. The problem of economic dispatch and its solutions have evolved over the years. The evolution timeline of it could be divided into the following three major periods:

1. Classical dispatch (1970's – 1990's)
2. Market-based dispatch (1990's – 2010's)
3. Smart dispatch (2010's –)

Classical dispatch [2]

Since the birth of control center's energy management system, classical dispatch monitors load, generation and interchange (imports/exports) to ensure balance of supply and demand. It also maintains system frequency during dispatch according to some regulatory standards, using Automatic Generation Control (AGC) to change generation dispatch as needed. It monitors hourly dispatch schedules to ensure that dispatch for the next hour will be in balance. Classical dispatch also monitors flows on transmission system. It keeps transmission flows within reliability limits, keeps voltage levels within reliability ranges and takes corrective action, when needed, by limiting new power flow schedules, curtailing existing power flow schedules, changing the dispatch or shedding load. The latter set of monitoring and control functions is typically performed by the transmission operator. Traditionally, generation scheduling/dispatch and grid security are separate independent tasks within control centers. Other than some ad hoc analysis, classical dispatch typical only addresses the real-time condition without much consideration of scenarios in the past or the future.

Market-based dispatch [3,4,5]

Ensuring reliability of the physical power system is no longer the only responsibility for the RTO/ISOs. A lot of the RTOs/ISOs are also responsible for operating wholesale electricity markets. To facilitate market transparency and to ensure reliability of the physical power system, an optimization-based framework is used to provide an effective context for defining comprehensive rules for scheduling, pricing, and dispatching. Taking advantage of the mathematical rigor contained in formal optimization methodology, the rules are likely to be more consistent, and thus more defensible against challenges that invariably arise in any market. Congestion management via the mechanism of locational marginal pricing (LMP) becomes an integral part of design of many wholesale electricity markets throughout the world and security-constrained economic dispatch (SCED) becomes a critical application to ensure the transmission constraints are respected while generation resources are being dispatched economically. The other important aspect of market-based dispatch is the size of the dispatch system. A typical system like PJM or Midwest ISO is usually more than 100GW of installed capacity. Advances in mathematical algorithms and computer technology really make the near real-time dispatch and commitment decisions a reality.

Smart dispatch

Smart dispatch (SD) is envisioned to be the next generation of resource dispatch solution particularly designed for operating in the smart grid environment [6]. The "smartness" of this new era of dispatch is to be able to manage highly distributed and active generation/demand resources in a direct or indirect manner. With the introduction of distributed energy resources such as renewable generations, PHEVs (Plug-in Hybrid Electric Vehicles) and demand response, the power grid will need to face the extra challenges in the following areas:

- Energy balancing
- Reliability assessment
- Renewable generation forecasting
- Demand forecasting
- Ancillary services procurement
- Distributed energy resource modeling

A lot of the new challenges are due to the uncertainties associated with the new resources/devices that will ultimately impact both system reliability and power economics.

One way to cope with uncertainties is to create a better predictive model. This includes better modeling of transmission constraints, better modeling of resource characteristics such as capacity limits and ramp rates, and more accurate demand forecasting. It is our belief that providing a forward-looking view of system conditions and generation patterns to system operators is deemed critical for the success of efficient system operations in the future.

Another way to cope with uncertainties is to address the robustness of dispatch solutions. Optimality or even feasibility of dispatch solutions could be very sensitive to system uncertainties. Reserve requirements and "n-1" contingency analysis are traditional ways to ensure certain robustness of a given system. Scenario-based (Monte-Carlo) simulation is another common technique for assessing economic or reliability impact with respect to uncertainties such as demand forecast.

When compared to the classical dispatch which only deals with a particular scenario for a single time point, smart dispatch addresses a spectrum of scenarios for a specified time period (Figure 1). Thus the expansion in time and scenarios for SD makes the problem of SD itself pretty challenging from both a computational perspective and a user interface perspective. For example, effective presentation of multi-dimensional data to help system operators better visualize the system is crucial. Beside a forward-looking view for system operators, SD should also allow after-the-fact analysis. System analysts should be able to analyze historical data systematically and efficiently, establish dispatch performance measures, perform root-cause analysis and evaluate corrective

actions, if necessary. SD will become an evolving platform to allow RTOs/ISOs to make sound dispatch decisions.
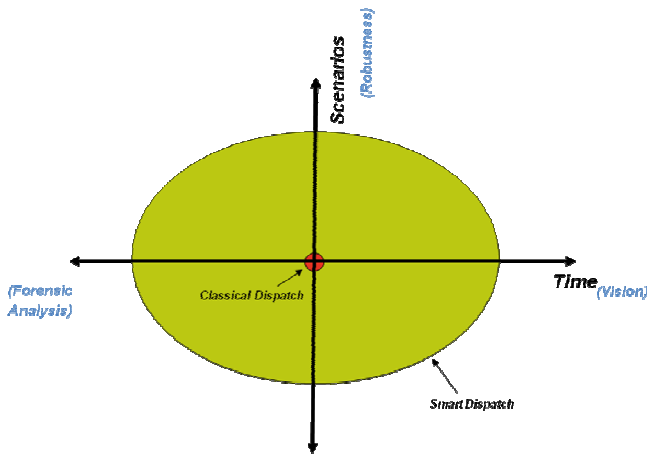

Figure 1. Time and Scenario Dimensions in Smart Dispatch

III. SMART DISPATCH FRAMEWORK

The objective of this section is to reveal the proposed framework of Smart Dispatch. The framework outlines the basic core SD functions for RTOs/ISOs operating in the smart grid environment. Some of the functional highlights and differentiations from classical dispatch are:

- Extension for price-based, distributed, less predictable resources
- Active, dynamic demand
- Modeling parameter adaptation
- Congestion management with security constrained optimization
- Continuum from forward scheduling to real-time dispatch
- Extension for dynamic, multi-island operation in emergency & restoration
- After-the-fact analysis for root-cause impacts and process re-engineering

One major core functions of Smart Dispatch is called Generation Control Application (GCA) which aims at enhancing operators' decision making process under changing system conditions (load, generation, interchanges, transmission constraints, etc.) in near real-time. GCA is composed of several distinct elements (Figure 2):

- Multi-stage Resource Scheduling Process (SKED 1,2&3)
- Comprehensive Operating Plan (COP)
- Adaptive Model Management

The multi-stage resource scheduling (SKED) process is security constrained unit commitment and economic dispatch sequences with different look-ahead periods (e.g. 6 hours, 2 hours and 20 minutes) updating resource schedules at different cycle frequencies (e.g. 5min, 15min or hourly). The results of

each stage form progressively refined regions that guide the dispatching decision space of the subsequent stages. Various SKED cycles are coordinated through the so-called Comprehensive Operating Plan (COP).
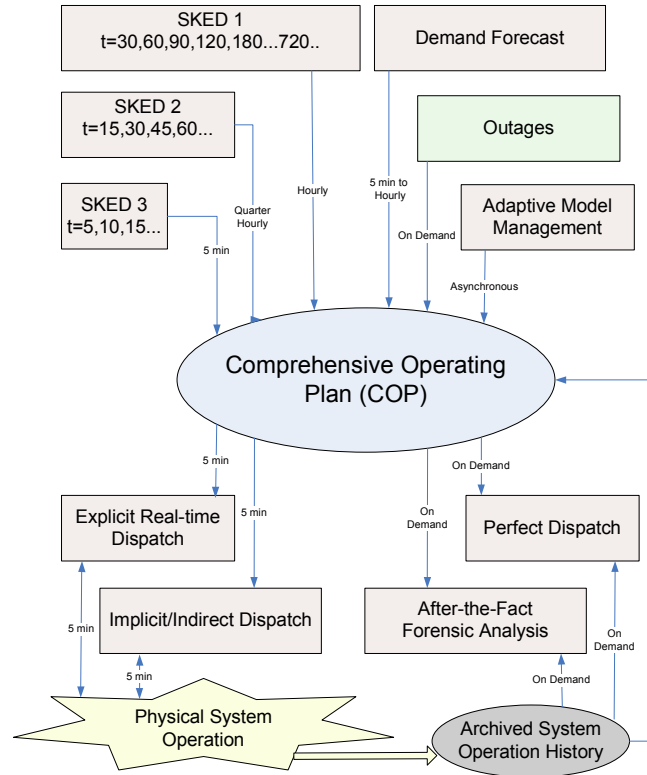

Figure 2. Smart Dispatch Framework

COP is a central repository of various kinds of scheduling data to and from a certain class of power system applications. COP presents a comprehensive, synchronized and more harmonized view of scheduling data to various applications related to power system operations. The class of scheduling data of interest includes the followings:

- Resource (renewable/non-renewable) MW schedule
- Demand forecast
- Outage schedule
- Transaction and interchange schedule
- Transmission constraint limit schedule
- Reserve and regulation requirement schedule
- Resource characteristics schedule

COP also contains comprehensive summary information. Summary information could be rollups from a raw data at a lower level (e.g. resource level) according to some pre-defined system structures.

COP has a *presentation layer* or a set of operator user interfaces (UIs) of its own to support system operator decision making. However, it does not intend to replace but supplement UIs of individual scheduling applications. COP has a *service*

layer to provide a set of APIs to interact with external power system applications or data sources. COP also has a *business application layer* that performs validation, translation, transformation, consolidation and harmonization of various asynchronized scheduling data. Lastly, COP has a *persistence data layer* for storing key scheduling data related to power system operations (Figure 3).
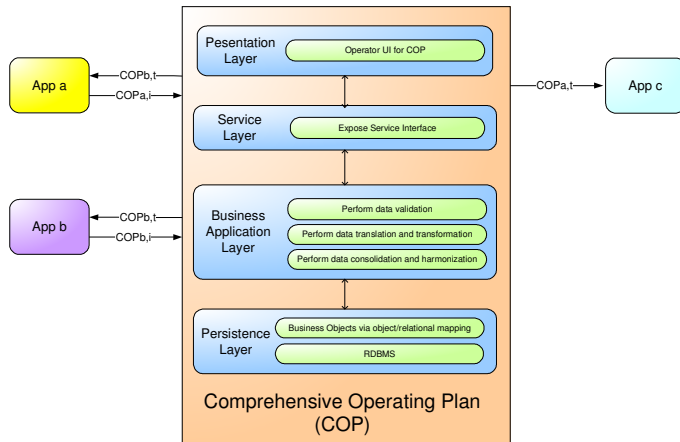

Figure 3. Comprehensive Operating Plan

Adaptive Model Management as shown in Figure 2 consists of two parts: Adaptive Constraint Modeling (ACM) and Adaptive Generator Modeling (AGM).

ACM will use intelligent methods to preprocess transmission constraints based on historical and current network conditions, load forecasts, and other key parameters. It should also have ability to achieve smoother transmission constraint binding.

AGM will provide other GCA components with information related to specific generator operational characteristics and performances. The resource "profiles" may contain parameters such as ramp rate, operating bands, predicted response per MW of requested change, Max & Min limits, etc.

Another major core functions of Smart Dispatch is After-the Fact Analysis (AFA). AFA aims at providing a framework to conduct forensic analysis. AFA is a decision-support tool to:

a. Identify root cause impacts and process re-engineering.

b. Systematically analyze dispatch results based on comparison of actual dispatches with idealized scenarios.

c. Provide quantitative and qualitative measures for financial, physical or security impacts on system dispatch due to system events and/or conditions.

One special use case of AFA is the so-called "Perfect Dispatch" (PD). The idea of PD was originated by PJM [7]. PD calculates the hypothetical least bid production cost commitment and dispatch, achievable only if all system conditions were known and controllable. PD could then be used to establish an objective measure of RTO/TSO's performance (mean of % savings, variance of % savings) in

dispatching the system in the most efficient manner possible by evaluating the potential production cost saving derived from the PD solutions.

The rest of the paper will focus on the discussion of GCA and its interaction with COP.

IV. GENERATION CONTROL APPLICATION

Generation Control Application (GCA) is an application designed to provide dispatchers in large power grid control centers with the capability to manage changes in load, generation, interchange and transmission security constraints simultaneously on a intra-day and near real-time operational basis. GCA uses least-cost security-constrained economic scheduling and dispatch algorithms with resource commitment capability to perform analysis of the desired generation dispatch. With the latest State Estimator (SE) solution as the starting point and transmission constraint data from the Energy Management System (EMS), GCA Optimization Engines (aka Scheduler or SKED) will look ahead at different time frames to forecast system conditions and alter generation patterns within those timeframes.

Based on the high-level introduction in Section III, this section will focus on the functionality of SKED engines and its coordination with COP.

A. SKED Optimization Engines

SKED is a Mixed Integer Programming (MIP) / Linear Programming (LP) based optimization application which includes both unit commitment and unit dispatch functions. SKED can be easily configured to perform scheduling processes with different heart beats and different look-ahead time. A typical configuration for GCA includes three SKED sequences:

- SKED1 provides the system operator with intra-day incremental resource (including generators and demand side responses) commitment/de-commitment schedules based on Day-ahead unit commitment decision to manage forecasted upcoming peak and valley demands and interchange schedules while satisfying transmission security constraints and reserve capacity requirements. SKED1 is a MIP based application. It is typically configured to execute for a look-ahead window of 6-8 hours with viable interval durations, e.g., 15-minute intervals for the 1st hour and hourly intervals for the rest of study period.

- SKED2 will look 1-2 hour ahead with 15-minute intervals. SKED2 will fine-tune the commitment status of qualified fast start resources and produce dispatch contours. SKED2 also provides resource ramping envelopes for SKED3 to follow (Figure 4).

- SKED3 is a dispatch tool which calculates the financially binding base points of the next five-minute dispatch interval and advisory base-points of the next several intervals for each resource (5 min, 10 min, 15 min, etc). SKED3 can also calculate ex-ante real-time LMPs for the financial binding interval and advisory

price signals for the rest of study intervals. SKED3 is a multi-interval co-optimization LP problem. Therefore, it could pre-ramp a resource for the need of load following and real-time transmission congestion management.
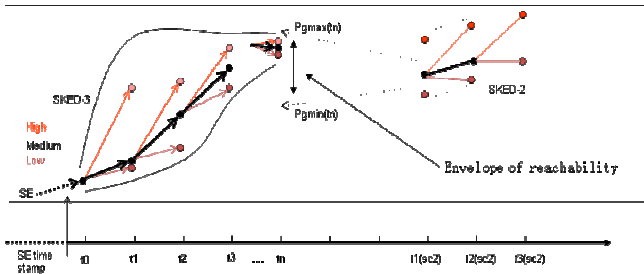

Figure 4. SKED 2 and SKED 3 Coordination

SKED formulation can be generalized as below:

Objective Function

SKED objective function consists of all or some of the following cost items:

- Resource Startup/Shutdown cost and no-load cost
- Resource incremental energy cost
- Transaction cost
- Ancillary Services (i.e., regulation and spinning) procurement cost

Constraints

All or some of the following constraints are enforced in SKED formulation:

- Load balancing
- Ancillary services requirements
- Resource capacity, including multiple limit sets, such as Economic Max/Min, AGM Max/Min, SKED Envelope Max/Min
- Resource Ramp Rate constraints
- Resource temporal constraints (min-run time, min-down time, etc.)
- Max number of startup/shutdown
- Daily energy constraints
- Emission constraints
- Transmission security constraints (support interval dependent constraint right hand side and MW dependent constraint penalty cost)

B. SKED and COP Coordination

GCA is built upon a modular and flexible system architecture. Although different SKED processes are correlated, they do not replay on each other. The orchestration between SKEDi is managed by COP. This design enables low-risk, cost-effective business process evolution. It also ensures high availability for the mission critical real-time GCA SKED

functions. Failure of any one or more SKED components will cause smooth degradation of, instead of abrupt service interruptions to, real-time dispatch instructions.

COP is the repository of all operating plans in a multi-stage decision process. Each SKEDi in the decision process generates a set of schedules that are reflected in its corresponding COP (COPi). The aggregated results from the multi-stage decision process are captured in the total COP (COPt), which is the consolidated outcome of the individual COPi's. SKED and COP coordination is illustrated in Figure 5.

Initialization of the COP for each operating day begins with the day-ahead schedule, which is based on the DAM financial schedules and then updated with Reliability Commitment results. Before any SKEDi is run in the current day of operation, the overall COPt is initialized with the day-ahead schedules. When COPt is suitably initialized, it will be used to generate input data for SKED1, SKED2 and SKED3. Results of SKEDi's are then used to update their respective subordinate COPi, which will cause COPt to be updated, and thus the overall iterative process continues.
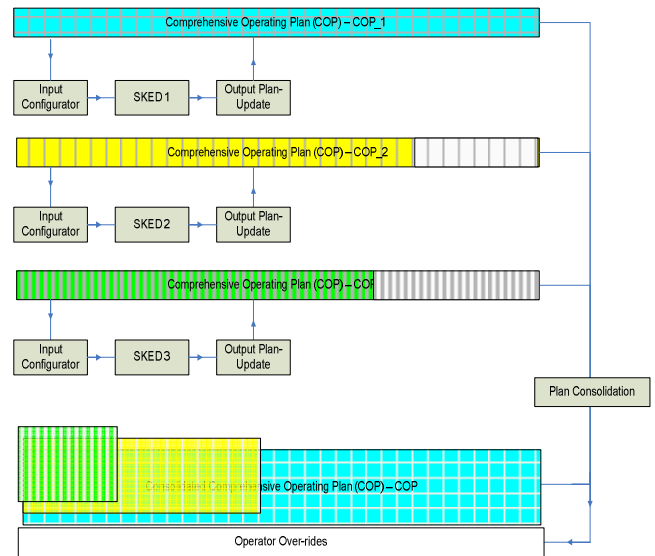

Figure 5. SKED and COP Coordination

C. Impact of Multi-interval Co-Optimization on Pricing

Different from the single-interval dispatch in most of the existing real-time energy market, SKED3 is a multi-interval co-optimization which means the coupling between study intervals and resource pre-ramping. In SKED3 solution a generator may be pre-ramped (out of merit dispatch) in an early interval for a need in a later interval in order to obtain minimized cost across all interval while the single-interval dispatch will minimize the cost of each individual interval.

SKED3 with binding ramp rate constrains will produce different LMPs than the LMPs produced by sequential single-interval dispatch. LMP is defined as the change in the objective function due to an increment in the demand at a

given network node and a given study interval. In extreme cases, negative LMPs may occur during the intervals with abrupt demand changes and generator ramping flexibility is limited.

For ex-ante pricing which is single interval based, a decoupled "pricing" solve may be performed after SKED3 multi-interval co-optimization. In the "pricing" solve, the binding ramp-rate constraints will be converted to generator capacity constraints with reduced MW limits in order to remove the pricing impact from interval coupling.

D. Multi-Scenario Solution and Robust Solution

In order to manage the uncertainties in the future intervals, the operator may need to run multiple scenarios in one SKED sequence, for example, scenarios for high/medium/low load forecast. For SKED1/2, multi-scenario solution can be used to determine the likelihood of a unit commitment. For instance, if a unit is committed in all three scenarios, it is very likely that the unit will be called on by the operator; on the other hand, if a unit is only committed in the high load scenario, it is not very likely to be called on by the operator.

A potential alternative to handle the uncertainties is to apply robust programming in order to achieve a more robust solution that coordinates the three demand scenarios, e.g. to have a single solution that guarantees the "reachability" for high and low demand scenarios.

V. CONCLUSIONS

This paper discusses the vision of Smart Dispatch in the context of control center's operations for the evolving smart grid environment. In particular, a new generation dispatch system to cope with the increasing amount of uncertainties being introduced by distributed energy resources is proposed. The proposed dispatch system will provide a better holistic and forward-looking view of system conditions and generation patterns and help system operators to make better decisions. Such features are deemed critical for the success of efficient power system operations in the near future.

VI. ACKNOWLEDGMENT

The views expressed in this paper are solely those of the authors, and do not necessarily represent those of AREVA.

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VIII. BIOGRAPHIES

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