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POSOCO / NLDC / CERC / 236

दिनांक : 01st June, 2015

To,

The Secretary,
Central Electricity Regulatory Commission
3rd & 4th Floor, Chanderlok Building,
36, Janpath, New Delhi- 110001

Subject: Views / Suggestions of POSOCO on the Draft Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015

Ref.: CERC Public Notice No. No.18/1/2013– Reg. Aff. (AS Reg.)/CERC dated: 1st May, 2015

Dear Sir,

With reference to the above mentioned notice of the Hon'ble Commission, the views / suggestions of POSOCO on the Draft Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 are enclosed herewith for your kind perusal.

Thanking You.

Yours Sincerely,

1/6/15

(S.S. Barpanda)
Addl. General Manager,
National Load Despatch Centre, POSOCO

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Adr (RE)
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Views / Suggestions of POSOCO on the CERC Draft Regulations on Ancillary Services Operations, 2015

The CERC Draft Regulations on Ancillary Services Operations, 2015 is an important step forward in the development of the Indian Electricity Market, where, the fourth essential pillar of Electricity Market is proposed to be implemented. The views / suggestions of POSOCO are as follows:

I. Regulation-wise Comments / Suggestions

A. Regulation 2. Definitions and Interpretation

"...j. "Load Despatch Centre" means National Load Despatch Centre, Regional Load Despatch Centre or State Load Despatch Centre, as the case may be, responsible for coordinating scheduling of the buyers and the sellers in accordance with the provisions of Grid Code;..."

"...m. Reserves Regulation Ancillary Services Provider" means the inter-State Generating Stations (ISGSs) having un-requisitioned surplus and eligible to participate in the Reserves Regulation Ancillary Services."

POSOCO Comments

The Hon'ble Commission may clarify the responsibility of the NLDC/RLDC/SLDC for coordinating scheduling in accordance with the provisions of Grid Code. The clause may be amended as follows:

"...j. "Load Despatch Centre" means National Load Despatch Centre, Regional Load Despatch Centre or State Load Despatch Centre, as the case may be, responsible for coordinating scheduling ~~**of the buyers and the sellers**~~ *in accordance with the provisions of Grid Code;..."*

The Hon'ble Commission may modify the definition of the Reserve Regulation Ancillary Services Provider after taking into account the fact that Regulation down services is also envisaged:

"...m. Reserves Regulation Ancillary Services Provider" means the ***Regional Entity Generating Stations*** ~~***inter-State Generating Stations (ISGSs) having un-requisitioned surplus and***~~ *eligible to participate in the Reserves Regulation Ancillary Services."*

B. Regulation 5. Eligibility for participation for Reserves Regulation Ancillary Services

"...5.1. All Inter-State Generating Stations whose tariff is determined or adopted by the Commission and are operating on part load and which have not received full requisition shall be eligible to participate for providing the Reserves Regulation Ancillary Services..."

POSOCO Comments

Some of the Inter-State Generating Stations whose tariff is determined or adopted by the Hon'ble Commission also have merchant capacity. It needs to be clearly specified that such plants which have a mix of regulated and merchant capacity shall not be eligible to participate in the Reserve Regulation Ancillary Services mechanism. Hence, it is proposed that only those regional entity generating stations whose tariff is determined or adopted by CERC for their full capacity are mandated to participate in the Reserves Regulation Ancillary Services Mechanism. The clause may be amended as follows:

*"...5.1. All ~~**Inter-State Generating Stations**~~ **Regional Entity Generating Stations** whose tariff is determined or adopted by the Commission ~~**and are operating on part load and which have not received full requisition shall be eligible to participate for providing**~~ **for their full capacity shall provide** the Reserves Regulation Ancillary Services..."*

C. Regulation 6. Role of Nodal Agency

"...6.1. Nodal Agency shall prepare merit order stack of un-requisitioned surplus capacities of Inter-State Generating Stations willing to participate in this mechanism based on the variable cost of generation, Declared Capacity and take despatch decision...."

POSOCO Comments

It seems that draft regulations have given a choice to ISGS willing to participate in the Reserves Regulation Ancillary Services. To continuously ensure the quality of electricity provided for customers, Ancillary Services must be mandatory for each despatchable generator. Hence, it is proposed that all regional entity generating stations whose tariff is determined or adopted by CERC for their full capacity mandatorily participate in the Reserves Regulation Ancillary Services Mechanism.

*"...6.1. Nodal Agency shall prepare merit order stack of ~~**un-requisitioned surplus capacities of Inter-State Generating Stations**~~ **Regional Entity Generating Stations** ~~**willing to participate in this mechanism**~~ based on the variable cost of generation, ~~**Declared Capacity and take despatch decision**~~...."*

D. Regulation 6. Role of Nodal Agency

"...6.2. Nodal agency shall prepare stack of un-requisitioned surplus capacities available of Inter-State Generating Stations from lower variable cost to higher generation cost in each time block..."

POSOCO Comments

The draft regulations have given an impression that stack prepared by the Nodal Agency will be based on the generation cost which is inclusive of fixed and variable costs. However, for economic despatch as intended by the Hon'ble Commission, a stack may be prepared only on the basis of variable cost and therefore, term "generation cost" may be replaced by "variable cost" in the draft regulations. The clause may be amended as follows:

*"...6.2. Nodal agency shall prepare stack of ~~**un-requisitioned surplus capacities available of Inter-State Generating Stations**~~ **Regional Entity Generating Stations** from lower variable cost to higher ~~**generation**~~ **variable** cost in each time block..."*

E. Regulation 6. Role of Nodal Agency

"...6.3. Nodal agency shall prepare region-wise merit order stack factoring inter-regional transmission constraints, if any...."

POSOCO Comments

The national grid faces both inter-regional and intra-regional constraints. The nodal agency may prepare merit order stack also considering the likelihood of intra-regional constraints as well. The clause may be amended as follows:

*"...6.3. Nodal agency shall prepare ~~region-wise~~ merit order stack factoring inter-regional **and intra-regional** transmission constraints, if any...."*

F. Regulation 9. Dispatch of Reserves Regulation Ancillary Services

"...9.1. Generation under the Reserves Regulation Ancillary Services shall be scheduled to the Regional Deviation Pool in each Regional Gird..."

POSOCO Comments

In the draft regulations, it appears that Reserves Regulation Ancillary Services shall be scheduled only to the Regional Deviation Pool of the respective Region. However, in case of major contingency (Generation station outage, Load crash etc.) in any one of the regions, Nodal Agency may give Regulation Up/Down instructions to Reserves Regulation Ancillary Services Provider located in other regions and the same may be scheduled to the Regional Deviation Pool of the region under contingency. The clause may be amended as follows:

*"...9.1. Generation under the Reserves Regulation Ancillary Services shall be scheduled to the Regional Deviation Pool in ~~each Regional Gird~~ **in any one or more Regional Grids as decided by the Nodal Agency** ..."*

G. Regulation 11. Scheduling of Reserves Regulation Ancillary Services

"...11.5. The energy despatched under Reserves Regulation Ancillary Services would be deemed as delivered at the Regional periphery..."

POSOCO Comments

The schedule of the Reserves Regulation Ancillary Services provider will be at ex-bus periphery, and therefore, the injection loss/withdrawal loss shall be applied as per existing regulations so that the losses will be adjusted in kind. The clause may be amended as follows:

*"...11.5. The energy despatched under Reserves Regulation Ancillary Services would be deemed as delivered ~~at the Regional periphery~~ **ex-bus** ..."*

H. Regulation 13. Reserves Regulation Ancillary Services Settlement

"...13.6. The Reserves Regulation Ancillary Services provider shall adjust the fixed charges to the original beneficiaries in proportion to the quantum scheduled from generating station...."

POSOCO Comments

It may be clarified by the Hon'ble Commission that *the Reserves Regulation Ancillary Services provider shall adjust the fixed charges to the original beneficiaries in proportion to the quantum surrendered from generating station.* The clause may be amended as follows:

*"...13.6. The Reserves Regulation Ancillary Services provider shall adjust the fixed charges to the original beneficiaries in proportion to the quantum ~~scheduled~~ **surrendered** from generating station...."*

II. Other Comments / Suggestions

A. Triggering Reserve Regulation Ancillary Service prior to application of Congestion Charges

In case of congestion in a certain transmission corridor, Nodal Agency may invoke Reserve Regulation Ancillary Service prior to application of congestion charges as per CERC (Measures to relieve congestion in real time operation) Regulations, 2009 as amended from time to time.

B. Retrospective Adjustments

It may be clarified in the Regulation itself that Incentive, Fuel Price Adjustment and other charges are covered in the markup to be notified by the Hon'ble Commission. Therefore, Truing up or Retrospective Adjustment of charges payable shall not be applicable to the quantum scheduled under Reserves Regulation Ancillary Services. On similar lines, markup for down regulation may be considered by the Hon'ble Commission.

C. Monthly Reconciliation

The Reserves Regulation Ancillary Services provider must reconcile with the respective RLDCs on monthly basis regarding the schedule and despatch of Reserves Regulation Ancillary Service in the previous month alongwith quantum of payable/receivable amounts.

D. International Experience

A literature review on the implementation and experience of Ancillary Services markets in international electricity markets such as Australia, United Kingdom, Nordic Countries and United States of America is placed at Annex – I. The references for the literature review are as follows:

- Grayson Heffner[1], Charles Goldman[1], Brendan Kirby[2] and Michael Kintner-Meyer[3]
  [1]Lawrence Berkeley National Laboratory, [2]Oak Ridge National Laboratory, [3]Pacific Northwest National Laboratory, Environmental Energy Technologies Division, May 2007 Loads Providing Ancillary Services: Review of International Experience
  http://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Loads_providing_Ancillary_Services_main_report_62701.pdf
- G.A. Pagani, M. Aiello, Energy market trading systems in G6 countries
  www.cs.rug.nl/~andrea/publications/energyMarketG6.pdf
- Preben Nyeng, System Integration of Distributed Energy Resources ICT, Ancillary Services, and Markets PhD Thesis, July 2010, Technical University of Denmark
  http://orbit.dtu.dk/services/downloadRegister/5568822/pny_phd_thesis%5B1%5D.pdf
- Lisa Cameron and Peter Cramton, The Role of the ISO in U.S. Electricity Markets: A Review of Restructuring in California and PJM, Electricity Journal, April 1999, 71-81
  ftp://www.cramton.umd.edu/papers1995-1999/99ej-role-of-the-iso-in-us-electricity-markets.pdf

ANNEX-2

Ancillary Services – Some International Practices

Ancillary Services Arrangements in the National Electricity Market Management Company (NEMMCO), Australia

NEMMCO is responsible for the security and reliability of the electricity grid. To fulfill this obligation, NEMMCO controls key technical characteristics of the system, notably frequency and voltage. Reserves relating to frequency control are procured through centralized markets operated by NEMMCO. Reserves relating to network control ancillary services (voltage control and network loading control) and system restart resources are procured through a tender process, resulting in bilateral contracts between NEMMCO and successful tenderers. Typical sources of ancillary services include automatic generation control, governor control, load shedding, and rapid loading or unloading of generating units.

The present Rules organize ancillary services into three "bundles" – Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), and System Restart Ancillary Services (SRAS). Since 2001 NEMMCO has operated markets for the delivery of frequency control ancillary services (FCAS, sometimes called market ancillary services) while continuing to purchase network control ancillary services (NCAS) and System Restart Ancillary Services (SRAS) under long-term bulk procurement agreements. Ancillary service costs as a percent of total market costs has been gradually decreasing due to use of competitive procurement processes for FCAS. Although Market Generators and Market Loads bid their output or loads into the FCAS on a daily basis, most of the FCAS market turnover is event driven. FCAS are the most frequently used and therefore the most costly, accounting for almost three fifths of total ancillary services turnover. Under the "causer-pays" system of settlement, NEMMCO determines and allocates ancillary services costs to the responsible market participant (e.g., Market Customers or Market Generators). Under the "causer pays" philosophy individual contribution to the aggregate deviation in frequency of the power system is assessed, and each Market Generator is required to participate in the causer pays regime. Those Market Generators are each allocated a 'causer pays' factor by NEMMCO on a monthly basis that represents the extent to which the generating unit(s) caused frequency deviations over the previous month. Generators contribute to the cost of regulation frequency control ancillary service in accordance with their causer pays factor. Historically, Market Generators pay about 30% of regulating service costs, and Market Customers pay the remainder. With the reduction in overall FCAS costs, NCAS costs have become a proportionally greater share of total ancillary services cost.

Frequency Control Ancillary Services (FCAS) are used to balance power supply and demand over intervals too short for the energy market to manage (e.g., less than five minutes). There are several different frequency control ancillary services, including two types of regulation services and six types of contingency services. *Regulation Raise and Lower Services* correct the supply and demand balance in response to minor deviations in demand or generation. These services are required dynamically and their delivery is centrally controlled by NEMMCO. Regulation frequency control services are provided by generators equipped with Automatic Generation Control. This allows NEMMCO to continually monitor system frequency and control generating units to ensure that frequency is maintained between 49.9 and 50.1 Hertz. Loads generally do not provide regulation frequency control. *Contingency frequency control services* are required for correcting the supply-demand balance following a major imbalance event, such as the failure of a generating unit or transmission line . Some forms of demand side participation – notably load shedding – can and do participate in providing contingency frequency control services.

There are strict rules governing participation for any resource providing FCAS, especially for the quick-response categories (e.g., Fast Raise and Fast Lower Service):

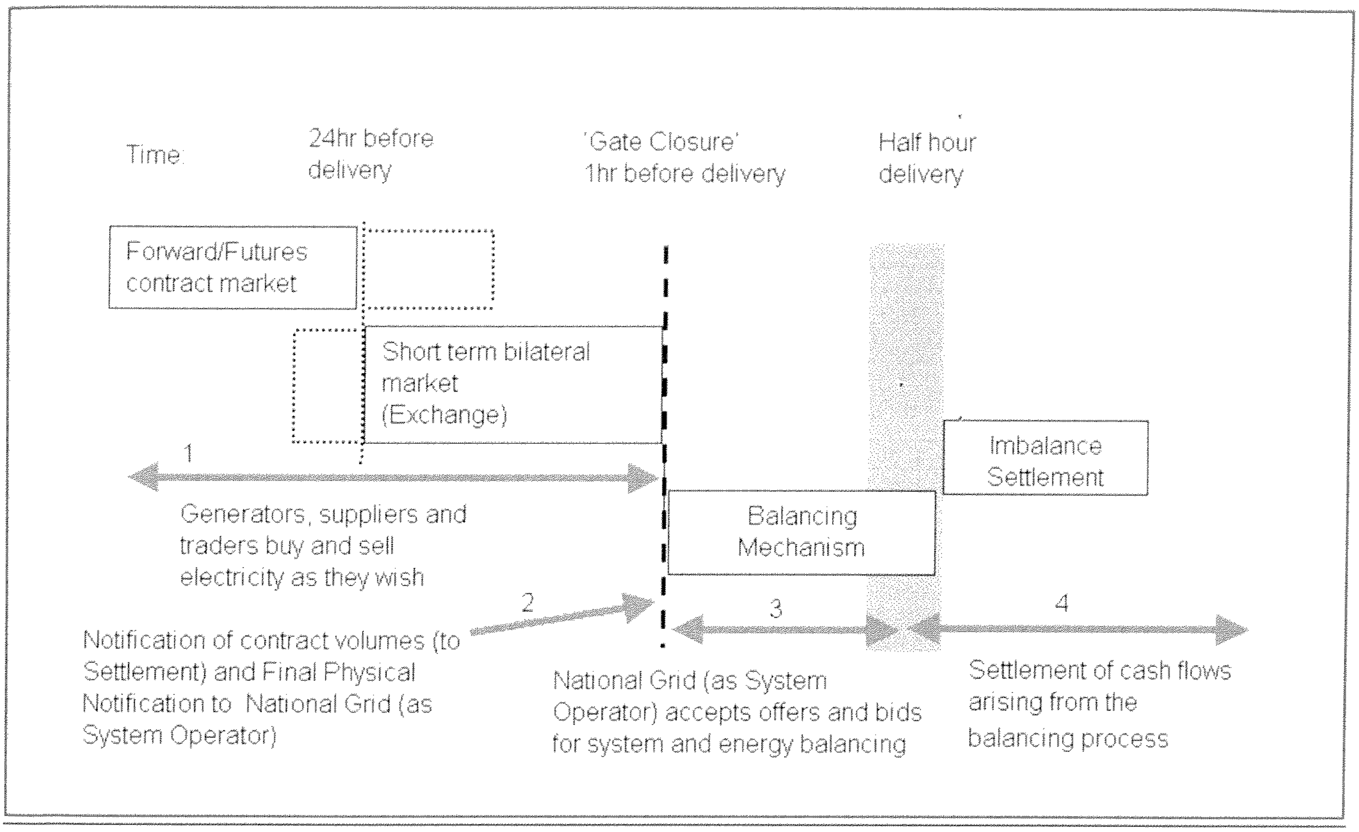
- The ancillary services generating unit or load must have a control system (either a proportional controller or switching controller) that automatically initiates a fast raise or fast lower response depending on which is called for by system frequency conditions;
- The ancillary services provider must inform NEMMCO of the details of the control system, in order to facilitate central dispatch or determining frequency settings;
- The ancillary services provider must install measurement equipment, at or near the connection point, allowing under-frequency load shedding (relaying) to occur at intervals of 50 millisecond or less.

Network Control Ancillary Services (NCAS) allow the operator to maintain and extend the operational efficiency and capability of the network within secure operating limits. There are two types of NCAS – voltage control (usually through generators with automatic voltage regulators (AVC) and synchronous condensers) and network loading control. Network loading control is required only in Victoria. NCAS are procured centrally on a biennial basis, but providers update their availability weekly. Load customers that meet the stringent response performance and telemetry requirements are eligible for this service, and loads now provide 100% of the network load control requirement.

United Kingdom: Ancillary Services and Load Participation

The British power market under BETTA is strictly an energy commodity market, with provisions accommodating bilateral long-term contracts, bilateral day-ahead trading, for forward and futures markets extending months to years ahead, and a small imbalance market. Almost all electricity (>90% of the wholesale market) is bought and sold by bilateral contracts between buyers and sellers in over-the-counter markets or in power exchanges such as the London-based UKPX or other European power exchanges (e.g., APX or EEX). Additional generation (or load) capacity is procured for use as Balancing Reserves, Standing Reserves, and Frequency Response under NGC's (National Grid

Company) Balancing Services umbrella. National Grid Company (NGC) operates the transmission grid in England, Wales, and Scotland, which deliver power to10 major distribution systems. Generators self-dispatch their plants rather than being centrally dispatched by the System Operator. There are three stages to the wholesale market, including settlement, which are illustrated in the following Figure-



The bilateral contracts markets for firm delivery of electricity operate from a year or more ahead of real time (i.e. the actual point in time at which electricity is generated and consumed) up to 24 hours ahead of delivery. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver or take delivery, of a given quantity of electricity for an agreed price at a specified day and time. The Forwards and Futures Contract Market is intended to reflect electricity trading over extended periods and represents the majority of trading volumes. Although the market operates typically up to a year ahead of real time, trading is possible up to one hour ahead of delivery (Gate Closure).

Power Exchanges operate over similar timescales, although trading tends to be concentrated in the last 24 hours. The markets are in the form of exchanges where participants trade a series of standardized blocks of electricity (e.g. the delivery of any amount of MWh over a specified period of the next day). Power Exchanges enable sellers (generators) and buyers (suppliers) to fine-tune their rolling half hour trade contract positions as their own demand and supply requirements firm up. The markets are firm bilateral markets and participation is optional. One or more published reference prices are available to reflect trading in the Power Exchanges.

The Balancing Mechanism operates from Gate Closure to real time and ensures that supply and demand can be continuously balanced in real time (Ref above fig). The System Operator acts as the sole counterparty to all Balancing Mechanism transactions. Participation in the optional Balancing Mechanism involves submitting 'offers' (proposed trades to increase generation or decrease demand) and/or 'bids' (proposed trades to decrease generation or increase demand). The mechanism operates on a 'pay as bid' basis. NGC purchases offers, bids and other Balancing Services to match supply and demand and resolve transmission constraints, thereby balancing the system in a manner consistent with operational standards and limits. There is no spot price for the two half-hour imbalance energy markets. Prices are set by using the averaging of the energy bids and offers, respectively; not at the marginal price. This yields a single system buy and system sell price. Prices for balance energy are valid for the entire the BETTA system, omitting locational energy pricing methods. Network constraint management is settled via transmission charges, separate from energy settlements.

Power flows are metered in real time to determine the actual quantities of electricity produced and consumed at each location. The magnitude of any imbalance between participants' contractual positions (as notified at Gate Closure) and the actual physical flow is then determined. Imbalance volumes are settled at either the System Buy Price (SBP) or System Sell Price (SSP), depending on whether the seller or buyer is long or short.

Ancillary and "Other Services" are part of the Balancing Mechanism and are procured from both authorized electricity operators (AEOs), who own and operate generators, and other commercial entities, generally load customers or aggregators with backup generators and demand response resources. The total value of ancillary and other services is about 1.1% of the total electricity market. Customer loads are only eligible to provide frequency response and reserve services, either as a direct customer or as part of a load block aggregated by a retail provider. From a technical point of view, it is difficult for customer loads to provide other ancillary services (reactive power support, fast start, and black start). The fast start units are gas turbine units that start rapidly from standstill and are used as next-start units in a black start scheme. NGC whenever possible seeks competitive procurement of ancillary services. This typically involves issuing tenders that document the terms and conditions of the service sought. NGC selects the lowest cost bid meeting the contract requirements. For services with insufficient competition, NGC will negotiate bilateral contract with individual service providers. The procurement guidelines are generally inclusive of frequency response products from demand-side providers and reactive power and fast and standing reserves and frequency response products from small generators. NGC is interested in attracting more demand side resources into existing market structures or developing new ancillary and other service products that will utilize emerging demand/load management approaches.

NGC procures frequency response as a commercial service from demand side resources, which typically consists of load blocks contracted between customers and load aggregators. Size eligibility requirement is 3 MW or more for any individual load. The frequency threshold at which the relay disconnects the load is negotiated based on how often the load is prepared and willing to be disconnected. Historically, a setting of 49.7 Hz has yielded about 30 load shed events/year . On average, the load curtailments lasted between 15 and 20 minutes. NGC has provisions that allow the under-frequency relays to be disarmed when the load is unavailable, allowing an important reassurance to the end-use customer against unwanted interruption risk.

A demand response pilot program, called the Demand Turndown Pilot, was initiated in summer 2004. A primary objective of the Pilot program was to increase competition in the balancing services market by increasing the number of contingency reserve resources (i.e. customer loads) and to free up generation capacity for the energy markets or other reserve services. The pilot project was targeted to large customers with back-up generators and/or significant load reduction capabilities that could be aggregated by load aggregators in the Balancing Mechanism as warming reserve. Because of the low turnout, NGC revised the design of the pilot for the winter 2004/2005 to allow participating customers more flexibility in determining an option price associated with time windows during which their loads could be curtailed. This new program feature was made available in addition to the existing fixed time window product (9:00 a.m. to 11:00 a.m. for the winter). The overall experience during both summer and winter seasons was disappointing in terms of participation levels among loads, and the Pilot was discontinued.

The Nordic Electricity Market

The four economies comprising the Nordic region (Denmark, Finland, Norway and Sweden) were among the very first to restructure their electricity industries and introduce competitive wholesale electricity markets. Nord Pool, established in 1993, was the world's first multinational power exchange. Nord Pool operates several regional financial and physical markets, most notably the forward market (Eltermin and Eloptions), the day ahead market (Elspot), and the real-time or hourly market (Elbas, or Electricity Balancing Adjustment Service). Elbas is the intraday (hourly) market, currently serving only Finland, Eastern Denmark, and Sweden. The Elbas market supplements Elspot and the national Nordic regulating power markets. Nord Pool is an energy-only market but is supported by limited operating reserves financed by the national grid operators via capacity payments. There is significant price volatility under this market design, as high spot prices signal consumers to reduce their electricity demand (or use back-up sources) and power companies to invest in generation capacity and/or demand flexibility. In the Nordic model two types of reserves are used: (i) primary reserves, calculated based on dimensioning outages characteristics of the system; and (ii) secondary reserves, which serve both to relieve primary reserves after outages and also to cope with deviations from forecasts. Anytime there is a tight balance between demand and supply, the generators will have an incentive to bid their capacity into the day-ahead spot market instead of the hour-ahead Elbas or real-time regulating power market. The result would be a spot market that clears but insufficient generation reserves bidding into the Elbas or regulating power market, thus jeopardizing real-time system balance. The Nordic solution is to contact certain quantities of operating reserves to be available only in the regulating power market. Because the conditions placed on these secondary reserves are more "DR-friendly" (e.g., non-synchronized, 15 minute activation time), it is not surprising to find a very high level of demand response participation in the Nordic operating reserves scheme.

In September 2002 a common Nordic balancing market, the Regulating Power Market or RPM, was established. This Balancing Market is a key tool of all Nordic transmission system operators, as it provides the means for real-time balancing of electricity supply and demand due to load forecast errors, system disturbances, or other causes. Although each Nordic TSO operates its own variant of the RPM, the operating reserves of one TSO may be applied to relieve imbalances elsewhere in the Nordic grid. The Balancing Market ensures an efficient acquisition of reserves on an hourly basis, but does not in itself reduce the required amount of reserves. It was introduced as an efficient way of securing sufficient reserves from existing capacity during peak load periods. This helps control the risk associated with balance management, especially for the Norwegian and Danish TSOs who are financially responsible for real-time energy balancing. The basis for balance management of the synchronous system is frequency control. The entire Nordic power system comprises a single market for regulating power. A single merit order list is used, except when bottlenecks require the regulating power market to be divided. For each hour, the regulation price is determined in all Elspot areas as the margin price of activated bids in the joint regulation list. Reserves are categorized by whether they are automatically (via frequency control) or manually activated. Although the TSOs in the Nordic system operate individually in normal balancing operations, there is close cooperation with regard to managing system disturbances. The Nordic TSOs further disaggregate reserves into categories including

- Frequency controlled operating reserve (100 % activated between 49.9-50.1 Hz)
- Frequency controlled disturbance reserve (50% activated at 5 sec. and 100% at 30 sec.)
- Fast active reserve (15 min.)
- Slow active reserve (4-8 hours)
- Reactive reserve

The *frequency-controlled operating reserve* is an automatic upward and downward regulation reserve used to maintain grid frequency. Regulation is automatic and commonly implemented by a closed-loop frequency controller at the point of generation (e.g., automatic generator control). The operating reserve is designed to completely activate at 49.9 Hz and 50.1 Hz, respectively. This reserve accommodates any required upwards or downwards regulation within 2-3 minutes.

Frequency-controlled disturbance reserves are used when the frequency leaves the lower limit of normal operations (49.9Hz). Both contracted automated load shedding and governor controlled generation can be used. The response time is 5 seconds for activating 50% of the reserve, with 100% of the reserves activated within 30 seconds. Telemetry requirements are in line with those for frequency-controlled operating reserves.

Fast active disturbance reserves and *slow active disturbance reserves* are used to progressively replace and restore frequency-controlled operating and disturbance reserves. The fast active disturbance reserves must have 15 minute availability to restore the frequency responsive operating and disturbance reserves, while slow active reserves may take up to 4 hours to come on line. System operators secure fast and slow active reserves through bilateral agreements or from their own reserves. Reserves resources generally consist of gas turbines, thermal power plants, hydropower and load shedding. Active disturbance reserves are called upon infrequently; just three times in the past five years.

California ISO, USA :

California's electricity market consists of: (1) a number of competing forward markets for energy, (2) day-ahead and hour-ahead markets for transmission and for ancillary services, and (3) a real-time energy spot market. Scheduling coordinators (SCs) run the forward energy markets. The ISO manages the spot market. It is also currently responsible for conducting the transmission and ancillary services markets. Currently, California has about thirty SCs. Most of these SCs establish day-ahead schedules and prices through bilateral contracting. One SC, the Automated Power Exchange, runs a continuous market. Another SC, the Power Exchange (PX), was established as California's "official" energy market. The PX runs auctions that establish energy prices and schedules on both a day-ahead and an hour-ahead basis. It currently handles most of the trading in the California market. However, part of the reason for the PX's dominance may be the fact that all California utilities are required to bid their generation and loads into the PX for the first five years of the California market.

The PX energy market and the ISO markets for transmission and ancillary services are conducted in a sequence. First, the PX conducts the day-ahead market for energy, which is followed by ISO markets for transmission and ancillary services. Second, the PX conducts a market for energy one hour in advance of the actual dispatch hour, which is followed by the ISO's hour-ahead markets for transmission and ancillary services. Finally, in real time, the ISO conducts the energy spot market. California uses a multi settlement system, which means that the prices and quantities established in market phases prior to dispatch represent binding forward contracts for the purchase and sale of electricity. Under this system, day ahead PX transactions are settled at the day-ahead PX energy price and hour-ahead PX transactions are settled at the hour ahead PX energy price. Similarly, transmission prices established in the day-ahead market apply to flows scheduled in the PX's day-ahead market while hour-ahead transmission prices apply only to flows scheduled in the PX's hour-ahead market. Finally, any difference between scheduled flows and actual flows in the real-time market are settled at the ISO determined spot energy price. Because the prices established in the scheduling phases of the market are binding in a multi settlement system, these scheduling phases are also referred to as forward markets.

After managing congestion and allocating transmission, the ISO also conducts a day-ahead market for four ancillary services, regulation, spinning reserves, non-spinning reserves, and replacement reserves. The ISO procures regulation services from generators that are equipped to respond to its automatic generation control (AGC) signals. These signals direct generators to increase or reduce generation on a minute-to-minute basis so that system frequency is maintained within a range dictated by reliability considerations. The three types of reserves differ by the amount of time that the generator has before it must begin supplying power to the grid and whether or not the facility must be consuming resources while waiting in reserve. Spinning reserves must be on-line and synchronized with the system so that they can begin producing power as soon as they are called upon. Non-spinning reserves are offline but must be fully available within ten minutes. Replacement reserve is capacity that can be delivered as energy within one hour. Suppliers submit bids for these four markets with their day ahead energy schedules, offering both a capacity and an energy bid. Winning bidders are chosen solely on the basis of their capacity bids; the energy bids are used to determine whether the plant will be run in the real-time spot market. The ISO resolves the four ancillary service markets in sequence, procuring regulation first and replacement reserves last. Any bid that is not accepted in the first market is automatically assumed to be a bid in the next market, and so on. Thus, while suppliers must decide upfront how they want to allocate their generation between the energy market and the ancillary services market, they do not need to decide in advance which ancillary service they would like to offer. Currently the ISO verifies that the results of the ancillary services auctions do not impose additional transmission constraints. There may be a further integration of ancillary services auctions and transmission auctions in the future. Ancillary services costs will be allocated pro-rata based on an SC's load and resource mix.

The ISO conducts the energy spot market in real time, balancing supply and demand while maintaining voltage and frequency within tight bands. Its resources consist of participants' supplemental energy bids submitted prior to the operating hour, as well as the generation capacity of winning bidders from the four ancillary service markets. If real-time demand exceeds scheduled supply, the ISO dispatches these resources in merit order and the spot price is the price of the most expensive energy bid called on in the merit order. If real time supply exceeds demand, the ISO uses market participants' adjustment bids to increase demand or reduce supply. In this case, the spot price is determined by the least profitable adjustment bid accepted. The energy spot price is computed every ten minutes. All adjustments ordered by the ISO in real time are settled at the spot price in force when the instruction was given to the generator. Similarly, any market participant that over delivers (under delivers) energy, relative to scheduled amounts, is paid (must pay) the spot price for that energy.

The PJM , USA:

In the real-time spot market, the ISO continuously optimizes its economic dispatch to meet demand while respecting reliability constraints. It also runs a program every five minutes to compute an LMP (locational marginal Prices) for each node on the grid. All generators that inject power into the same location receive the same LMP (i.e., the locational price where power is injected into the system) per MWh provided. Similarly, all grid users at the same location pay the same LMP (i.e. the locational price where power is withdrawn from the system) per MWh consumed. The difference between LMPs at any two nodes on the system is the charge for transporting electricity from one node to the other. Because LMPs are typically lower at points of injection than they are at points of withdrawal, the cost of transporting electricity to a particular withdrawal point is typically positive. A PJM participant that submits a balanced schedule of injections and withdrawals to the ISO would be similar to an SC in the California system. To the extent that such an entity adheres to its balanced schedule in real time, it would pay only the cost of transportation between its injection and withdrawal points (i.e., the difference between the LMPs at points of injection and the LMPs at points of withdrawal.) However, any imbalances between the entity's scheduled supplies and loads would face the same LMPs that would apply to centrally dispatched transactions. Hence, self-scheduled generators that inject excess energy into the grid would be paid the LMP at the injection point while self-scheduled load withdrawing "excess" energy from the grid would pay the LMP at the point where energy is withdrawn.

The PJM ISO procures essentially the same ancillary services as the California ISO. However, it procures these services on an administrative basis, allocating costs in proportion to use of grid. All purchasers in PJM pay a charge covering the cost of these ancillary services, as well as control area operations, and marginal line losses. Line losses will eventually be incorporated into the LMP.