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Electricity Markets Modeling Considering Complex Contracts and Aggregators

by

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Dedicated to those who love me

“Learning is the only thing the mind never exhausts,
Never fears and never regrets”
(Leonardo da Vinci)

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Abstract

All over the world, the liberalization of electricity markets, which follows different paradigms, has created new challenges for those involved in this sector. In order to respond to these challenges, electric power systems suffered a significant restructuring in its mode of operation and planning. This restructuring resulted in a considerable increase of the electric sector competitiveness. Particularly, the Ancillary Services (AS) market has been target of constant renovations in its operation mode as it is a targeted market for the trading of services, which have as main objective to ensure the operation of electric power systems with appropriate levels of stability, safety, quality, equity and competitiveness.

In this way, with the increasing penetration of distributed energy resources including distributed generation, demand response, storage units and electric vehicles, it is essential to develop new smarter and hierarchical methods of operation of electric power systems. As these resources are mostly connected to the distribution network, it is important to consider the introduction of this kind of resources in AS delivery in order to achieve greater reliability and cost efficiency of electrical power systems operation.

The main contribution of this work is the design and development of mechanisms and methodologies of AS market and for energy and AS joint market, considering different management entities of transmission and distribution networks. Several models developed in this work consider the most common AS in the liberalized market environment: Regulation Down; Regulation Up; Spinning Reserve and Non-Spinning Reserve. The presented models consider different rules and ways of operation, such as the division of market by network areas, which allows the congestion management of interconnections between areas; or the ancillary service cascading process, which allows the replacement of AS of superior quality by lower quality of AS, ensuring a better economic performance of the market.

A major contribution of this work is the development an innovative methodology of market clearing process to be used in the energy and AS joint market, able to ensure viable and feasible solutions in markets, where there are technical constraints in the transmission network involving its division into areas or regions. The proposed method is based on the determination of Bialek topological factors and considers the contribution of the dispatch for all services of increase of generation (energy, Regulation Up, Spinning and Non-Spinning reserves) in network congestion. The use of Bialek factors in each iteration of the proposed methodology allows limiting the bids in the market while ensuring that the solution is feasible in any context of system operation.

Another important contribution of this work is the model of the contribution of distributed energy resources in the ancillary services. In this way, a Virtual Power Player (VPP) is considered in order to aggregate, manage and interact with distributed energy resources. The VPP manages all the agents aggregated, being able to supply AS to the system operator, with the main purpose of participation in electricity market. In order to ensure their participation in the AS, the VPP should have a set of contracts with the agents that include a set of diversified and adapted rules to each kind of distributed resource.

All methodologies developed and implemented in this work have been integrated into the MASCEM simulator, which is a simulator based on a multi-agent system that allows to study complex operation of electricity markets. In this way, the developed methodologies allow the simulator to cover more operation contexts of the present and future of the electricity market. In this way, this dissertation offers a huge contribution to the AS market simulation, based on models and mechanisms currently used in several real markets, as well as the introduction of innovative methodologies of market clearing process on the energy and AS joint market.

This dissertation presents five case studies; each one consists of multiple scenarios. The first case study illustrates the application of AS market simulation considering several bids of market players. The energy and ancillary services joint market simulation is exposed in the second case study. In the third case study it is developed a comparison between the simulation of the joint market methodology, in which the player bids to the ancillary services is considered by network areas and a reference methodology. The fourth case study presents the simulation of joint market methodology based on Bialek topological distribution factors applied to transmission network with 7 buses managed by a TSO. The last case study presents a joint market model simulation which considers the aggregation of small players to a VPP, as well as complex contracts related to these entities. The case study comprises a distribution network with 33 buses managed by VPP, which comprises several kinds of distributed resources, such as photovoltaic, CHP, fuel cells, wind turbines, biomass, small hydro, municipal solid waste, demand response, and storage units.

Resumo

A liberalização dos mercados de energia elétrica, considerando de diferentes paradigmas, cria novos desafios para as entidades que operam neste sector. Em resposta a estes desafios, os sistemas elétricos de energia sofreram uma reestruturação significativa no seu modo de operação e planeamento. Este processo de reestruturação originou num aumento considerável da competitividade do sector elétrico. Como parte integrante dos mercados elétricos, o mercado de serviços de sistema tem vindo a ser alvo de constantes remodelações no seu modo de operação, visto ser um mercado direcionado para a negociação de serviços que possuem como principal objetivo assegurar a exploração dos sistemas elétricos de energia com níveis apropriados de estabilidade, segurança, qualidade, igualdade e competitividade.

Neste sentido, com a crescente penetração de recursos energéticos distribuídos nomeadamente a produção distribuída, a gestão da procura (*demand response*), as unidades de armazenamento de energia elétrica e os veículos elétricos, torna-se imprescindível desenvolver novas metodologias de operação dos sistemas elétricos de energia, mais inteligentes e hierarquizadas. Estando estes recursos maioritariamente ligados à rede de distribuição, é importante considerar a sua introdução no fornecimento de serviços de sistema com o objetivo de obter uma maior fiabilidade e eficiência nos custos de operação dos sistemas elétricos.

O principal contributo deste trabalho é a conceção e desenvolvimento de metodologias e mecanismos de mercado de serviços de sistema e de mercados conjuntos de energia e serviços de sistema, considerando as diferentes entidades de gestão das redes de transmissão e distribuição. Os vários modelos desenvolvidos neste trabalho consideram os serviços de sistema mais comuns em ambiente de mercado liberalizado: *Regulation Down*; *Regulation Up*; *Spinning Reserve*; e *Non-Spinning Reserve*. Os modelos apresentados consideram diferentes regras e modos de funcionamento como a divisão do mercado em áreas da rede, que permite uma gestão do congestionamento nas interligações entre as áreas, ou o processo de cascata de serviços de sistema (*ancillary services cascading process*), que permite a substituição de serviços de sistema de qualidade superior por serviços de sistema de qualidade inferior, assegurando um melhor desempenho económico do mercado.

Um grande contributo deste trabalho reside no desenvolvimento de uma metodologia inovadora de encontro de ofertas a ser utilizada no mercado conjunto de energia e serviços de sistema, capaz de garantir soluções viáveis e exequíveis em mercados onde existam restrições técnicas na rede de transmissão que impliquem a sua divisão em áreas ou regiões. O método proposto baseia-se na determinação dos fatores topológicos de Bialek e considera a contribuição do despacho da energia e dos serviços de sistema (*Regulation Up*, *Spinning* e *Non-spinning reserves*) no congestionamento da rede. O uso dos fatores de Bialek em cada iteração da metodologia proposta permite limitar as ofertas existentes no mercado, garantindo sempre que a solução encontrada é exequível em qualquer contexto de operação do sistema.

Outro aspeto importante neste trabalho é a modelação de recursos energéticos distribuídos nos serviços de sistema. Neste sentido, um *Virtual Power Player* (VPP) é considerado a fim de agregar, gerir e interagir com os recursos energéticos distribuídos. O VPP gere as necessidades dos agentes agregados, podendo fornecer serviços de sistema ao operador do sistema, tendo como

principal finalidade a participação no mercado de eletricidade. Para assegurar a sua participação nos serviços de sistema, o VPP deverá ter um conjunto de contratos com os agentes agregados que incluirão um conjunto de regras diversificadas e adequadas a cada tipo de recurso distribuído.

Todas as metodologias desenvolvidas e implementadas neste trabalho foram integrados no simulador MASCEM. Este é um simulador baseado num sistema multiagente que permite estudar a operação complexa dos mercados de eletricidade. Neste sentido, as metodologias desenvolvidas permitem ao simulador abranger mais contextos de operação do presente e futuro do mercado de eletricidade. Neste ponto de vista, esta dissertação oferece uma enorme contribuição na simulação do mercado de serviços de sistema, baseado em modelos e mecanismos utilizados atualmente em vários mercados reais, bem como na introdução de metodologias inovadores de encontro de ofertas no mercado conjunto de energia e serviços de sistema.

Nesta dissertação são apresentados cinco casos de estudo, cada um constituído por vários cenários. O primeiro caso de estudo ilustra a aplicação de simulação de mercado de serviços de sistema considerando várias ofertas de agentes de mercado. A simulação do mercado conjunto de energia e serviços de sistema é exposto no segundo caso de estudo. O terceiro caso de estudo desenvolve uma comparação entre a metodologia de simulação do mercado conjunto em que as ofertas dos agentes para os serviços de sistema é considerado por áreas da rede e uma metodologia de referência. O quarto caso de estudo apresenta a simulação da metodologia do mercado conjunto com base nos fatores topológicos de distribuição de Bialek aplicado a uma rede de transporte de 7 barramentos gerida por um *TSO*. O último caso de estudo apresenta a simulação do modelo de mercado conjunto em que considera a agregação de pequenos agentes de mercado a um VPP, bem como os contratos complexos associados a estas entidades. Este caso de estudo é constituído por uma rede de distribuição de 33 barramentos gerida por um VPP que comtempla vários tipos de recursos, tais como: unidades fotovoltaicas, cogeração, células de combustível, eólicas, biomassa, mini-hídricas, resíduos sólidos urbanos, *demand response*, e unidades de armazenamento.

Acronyms

Notation	Description
AC	Alternate Current
AGC	Automatic Generation Control
AMES	Agent-based Modelling of Electricity Systems
AS	Ancillary Services
ASM	Ancillary Services Market
BETTA	British Electricity Trading and Transmission Arrangements
BGSA	British Grid System Agreement
BRP	Balance Responsible Parties
BSC	Balancing and Settlement Code
CAISO	California Independent System Operator
CEGB	Central Electricity Generating Board
CHP	Combined Heat and Power
CMRI	CAISO Market Results Interface
CONOPT	CONtinuous global OPTimizer
CPLEX	Simplex algorithm and C programming
CRR	Congestion Revenue Rights
DAM	Day-Ahead Market
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DICOPT	Discrete and Continuous OPTimizer
DLC	Direct Load Control
DNO	Distribution Network Operator
DR	Demand Response
DSO	Distribution System Operator
GCP	Generation Curtailment Power
EMCAS	Electricity Market Complex Adaptive System
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FCT	Foundation for Science and Technology
FERC	Federal Energy Regulatory Commission
FPN	Final Physical Notifications
GAMS	General Algebraic Modeling System
HASP	Hour-Ahead Scheduling Process
ICL	Interagent Communication Language

IEEE	–	Institute of Electrical and Electronics Engineers
IFM	–	Integrated Forward Market
IPN	–	Initial Physical Notifications
ISO	–	Independent System Operator
LINDOGlobal	–	Linear, Integer, Nonlinear, Dynamic Optimization Global
LMP	–	Locational Marginal Price
MASCEM	–	Multi-Agent Simulator of Competitive Electricity Markets
MATLAB	–	MATrix LABoratory
MCP	–	Market Clearing Price
MIBEL	–	Mercado Ibérico de Electricidade
MINLP	–	Mixed Integer Non-Linear Programming
MIP	–	Mixed Integer Programming
MO	–	Market Operator
MPM-RRD	–	Market Power Mitigation & Reliability Requirements Determination
MSW	–	Municipal Solid Waste
NERC	–	North American Electric Reliability Corporation
NETA	–	New Electricity Trading Arrangements
NGC	–	National Grid Company
NGET	–	National Grid Electricity Transmission
NRC	–	Nuclear Regulatory Commission
NS	–	Non-Spinning Reserve
NSD	–	Non-Supplied Demand
NYISO	–	New York Independent System Operator
N2EX	–	Nord Pool Spot NASDAQ OMX Commodities
OAA	–	Open Agent Architecture
OASIS	–	Open Access Same-Time Information System
OMIclear	–	Sociedade de Compensação de Mercados de Energia
OMIE	–	Operador del Mercado Ibérico de Energia, Spanish pole
OMIP	–	Operador de Mercado Ibérico de Energia, Portuguese pole
OPF	–	Optimal Power Flow
PS	–	Power Systems
RD	–	Regulation Down
RMR	–	Reliability Must-Run
RTD	–	Real-Time Dispatch
RTED	–	Real-Time Economic Dispatch
RTM	–	Real-Time Market
RTUC	–	Real-Time Unit Commitment

RU	–	Regulation Up
RUC	–	Residual Unit Commitment
SBP	–	System Buy Price
SCED	–	Security Constrained Economic Dispatch
SCUC	–	Security Constrained Unit Commitment
SEPIA	–	Simulator for Electric Power Industry Agents
SESAM	–	Nord Pool Spot’s day-ahead trading system
SG	–	Smart Grid
SO	–	System Operator
SP	–	Spinning Reserve
SSP	–	System Sell Price
STUC	–	Short-Term Unit Commitment
TD	–	Trading Day
TH	–	Trading Hour
TM	–	Trading Month
TSO	–	Transmission System Operator
TY	–	Trading Year
V2G	–	Vehicle-to-Grid
VPP	–	Virtual Power Player
WECC	–	Western Electricity Coordinating Council

Nomenclature

Notation		**Description**	**Unit**	
α_i^d	–	Set of nodes supplied directly from node *i*	-	-
α_i^u	–	Set of nodes which supplying directly node *i*	-	-
Δt	–	Elementary period	hour	(h)
$\eta_{c(S)}$	–	Yield of charge process of the electricity network to the storage unit *S*	-	(%)
$\eta_{d(S)}$	–	Yield of discharge process of the electricity network to the storage unit *S*	-	(%)
i	–	Bus index	-	-
k	–	Market component index (1 – Regulation Down; 2 – Regulation Up; 3 – Spinning Reserve; 4 – Non-Spinning Reserve; 5 – Energy)	-	-
l	–	Load index	-	-
r	–	Resource index	-	-
t	–	Period index	-	-
y	–	Network branch index	-	-
z	–	Zone index	-	-
$\theta_{i(t)}$	–	Voltage angle at bus *i* in period *t*	radians	(rad)
$\theta_{i(t)}^{\max}$	–	Maximum voltage angle at bus *i*	radians	(rad)
$\theta_{i(t)}^{\min}$	–	Minimum voltage angle at bus *i*	radians	(rad)
$\theta_{j(t)}$	–	Voltage angle at bus *j* in period *t*	radians	(rad)
A_u	–	Upstream distribution matrix	-	-
B_{ii}	–	Imaginary part of the element in admittance matrix (susceptance) corresponding to the *i* row and *i* column	siemens	(S)
B_{ij}	–	Imaginary part of the element in admittance matrix (susceptance) corresponding to the *i* row and *j* column	siemens	(S)
$C_{AS(r,k,t)}^{\max}$	–	Resource *r* selling bid at market clearing price, in ancillary service commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$C_{b(l,t)}^{\max}$	–	Load *l* buying at market clearing price, for period *t*	monetary unit per	(m.u./W)

			watt	
$C_{Ch(S,k,t)}$	–	Charge price of storage unit *S*, in commodity *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{Dch(S,k,t)}$	–	Discharge price of storage unit *S*, in commodity *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{DG(DG,k,t)}$	–	Distribution generation unit *DG* selling bid price, for commodity *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{DG\,\mathrm{Rem}(DG)}$	–	Minimum remuneration of distributed generation unit *DG*	monetary unit per watt	(m.u./W)
$C_{DR\_A(l,k,t)}$	–	*DR_A* program price, for load *l*, for service *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{DR\_B(l,k,t)}$	–	*DR_B* program price, for load *l*, for service *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{GCP(DG,t)}$	–	Generation Curtailment Power cost coefficient of *DG* unit, in period *t*	monetary unit per watt	(m.u./W)
$C_{NSD(l,k,t)}$	–	Non-supplied demand cost of load *l* for each commodity *k*, in period *t*	monetary unit per watt	(m.u./W)
$C^{\max}_{S(r,k,t)}$	–	Resource *r* selling bid at market clearing price, in commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$C_{SP(SP,k,t)}$	–	Supplier *SP* selling bid price, for commodity *k*, in period *t*	monetary unit per watt	(m.u./W)
$C_{SP\,\mathrm{Rem}(SP)}$	–	Minimum remuneration of external supplier *SP*	monetary unit per watt	(m.u./W)
$D^{g}_{ij,r}$	–	Portion of generation due to generator *r*, that flows in line *i-j* (Topological generation factor matrix)	-	-
$E_{BatCap(S,t)}$	–	Battery energy capacity of storage unit *S*, in period *t*	watt hour	(Wh)
$E_{Stored(S,t)}$	–	Energy stored in storage unit *S* at the end of period *t* for energy, RU, SP and NS services.	watt hour	(Wh)
$E_{Stored\_RD(S,t)}$	–	Energy stored in storage unit *S* at the end of period *t* for energy and RD services.	watt hour	(Wh)
$F_{AS(k,t)}$	–	Objective function portion concerning the ancillary services *k* in period *t*	monetary unit	(m.u.)
$F_{AS\_req(z,k)}$	–	Ancillary service *k* requirement percentage factor provided by generation units from the region *z*.	percent	(%)

$F_{E(t)}$	–	Objective function portion concerning the energy service in period *t*	monetary unit-	(m.u.)
$F_{power(DG,t)}$	–	Reactive power percentage factor in relation to the active power, by distributed generation *DG*, in period *t*	percent	(%)
$F_{power(r,t)}$	–	Reactive power percentage factor in relation to the active power, by resource *r*, in period *t*	percent	(%)
$F_{power(SP,t)}$	–	Reactive power percentage factor in relation to the active power, by external supplier *SP*, in period *t*	percent	(%)
G_{ii}	–	Real part of the element in admittance matrix (conductance) corresponding to the *i* row and *i* column	siemens	(S)
G_{ij}	–	Real part of the element in admittance matrix (conductance) corresponding to the *i* row and j column	siemens	(S)
N_B	–	Total number of buses	-	-
N_{DG}	–	Total number of distributed generation units	-	-
N_{DG}^{i}	–	Total number of distributed generation units which belongs to bus *i*	-	-
N_{DG}^{w}	–	Total number of distributed generation units which belongs to the region *z*	-	-
N_{DG}^{z}	–	Total number of distributed generation units which belongs to the region *z*	-	-
N_L	–	Total number of loads	-	-
N_L^{i}	–	Total number of loads which belongs to bus *i*	-	-
N_L^{k}	–	Total number of loads in commodity *k*	-	-
N_L^{w}	–	Total number of loads which belongs to the region w	-	-
N_L^{z}	–	Total number of loads which belongs to the region *z*	-	-
N_K	–	Total number of commodity services	-	-
N_K^{DG}	–	Total number of distributed generation units in commodity *k*	-	-

N_K^R	–	Total number of resources in commodity *k*	-	-
N_K^S	–	Total number of storage units in commodity *k*	-	-
N_k^{SP}	–	Total number of external suppliers in commodity *k*	-	-
N_R	–	Total number of resources	-	-
N_R^i	–	Total number of resources which belongs to bus *i*	-	-
N_R^w	–	Total number of resources which belongs to region *w*	-	-
N_R^z	–	Total number of resources which belongs to region *z*	-	-
N_S^i	–	Total number of storage units *S* which belongs to bus *i*	-	-
N_{SP}	–	Total number of external suppliers	-	-
N_{SP}^i	–	Total number of external suppliers which belongs to bus *i*	-	-
N_{SP}^w	–	Total number of external suppliers which belongs to the region *w*	-	-
N_{SP}^z	–	Total number of external suppliers which belongs to the region *z*	-	-
N_Y	–	Total number of lines	-	-
N_Z	–	Total number of regional zones of ancillary services	-	-
$P_{AS(r,k,t)}$	–	Resource r scheduled power, in commodity *k* (only ancillary services), for period *t*	watt	(W)
$P_{AS\_req(z,k,t)}$	–	Active power demand requirement for the region *z*, in ancillary services *k*, in period *t*	watt	(W)
$P_{AS(r,k,t)}^{\max}$	–	Resource r maximum selling bid power, in commodity *k* (only ancillary services), for period *t*	watt	(W)
$P_{AS(r,k,t)}^{\min}$	–	Resource r minimum selling bid power, in commodity *k* (only ancillary services), for period *t*	watt	(W)
$P_{b(l,t)}$	–	Load *l* scheduled power, for period *t*	watt	(W)
$P_{b(l,t)}^i$	–	Load *l* scheduled power which belongs to bus *i*, for period *t*	watt	(W)
$P_{b(l,t)}^{\max}$	–	Load *l* maximum buying bid power, for period *t*	watt	(W)
$P_{b(l,t)}^{\min}$	–	Load *l* minimum buying bid power, for period *t*	watt	(W)
$P_{CAP(r,t)}$	–	Maximum power capacity of resource *r*, for period *t*	watt	(W)
$P_{CAP\_DG(DG,t)}$	–	Maximum power capacity of distributed generation unit *DG*,	watt	(W)

		for period *t*		
$P_{CAP\_SP(SP,t)}$	–	Maximum power capacity of external supplier *SP*, for period *t*	watt	(W)
$P_{Ch(S,k,t)}$	–	Active power charge of storage *S* for commodity *k*, in period *t*	watt	(W)
$P^{i}_{Ch(S,k,t)}$	–	Active power charge of storage *S* for commodity *k* at bus *i* in period *t*	watt	(W)
$P_{ChMax(S,k,t)}$	–	Maximum active power charge of storage *S* for commodity *k* in period *t*	watt	(W)
$P_{ChMax(S,t)}$	–	Maximum global active power charge of storage *S* in period *t*	watt	(W)
$P_{Dch(S,k,t)}$	–	Active power discharge of storage *S* for commodity *k* in period *t*	watt	(W)
$P^{i}_{Dch(S,k,t)}$	–	Active power discharge of storage *S* for commodity *k* at bus *i* in period *t*	watt	(W)
$P_{DchMax(S,k,t)}$	–	Maximum active power discharge of storage *S* for commodity *k* in period *t*	watt	(W)
$P_{DchMax(S,t)}$		Maximum global active power discharge of storage *S* in period *t*.	watt	(W)
$P_{DG(DG,k,t)}$	–	Active power generation of distributed generation unit *DG* for each service *k*, in period *t*	watt	(W)
$P^{i}_{DG(DG,k,t)}$	–	Active power generation of distributed generation unit *DG* at bus *i*, for each service *k*, in period *t*	watt	(W)
$P^{w}_{DG(DG,k,t)}$	–	Active power generation of distributed generation unit *DG* which belongs to the region *w*, for each service *k*, in period *t*	watt	(W)
$P^{z}_{DG(DG,k,t)}$	–	Active power generation of distributed generation unit *DG* which belongs to the region *z*, for each service *k*, in period *t*	watt	(W)
$P_{DGMax(DG,k,t)}$	–	Maximum active power generation of distributed generation unit *DG*, for service *k*, in period *t*	watt	(W)
$P_{DGMin(DG,k,t)}$	–	Minimum active power generation of distributed generation unit *DG*, for service *k*, in period *t*	watt	(W)
$P_{DGMin(DG)}$	–	Total minimum active power generation of distributed generation unit *DG*	watt	(W)
$P_{DG\,\mathrm{Rem}(DG)}$	–	Total minimum remuneration of distributed generation unit *DG*	monetary unit	(m.u.)

$P_{DGVar(DG)}$	–	Generation variation of distributed generator unit *DG* between periods	watt	(W)
$P_{Di(t)}$	–	Active power demand at bus *i* in period *t*	watt	(W)
$P_{DR\_A(l,k,t)}$	–	*DR_A* active power reduction, for load *l*, in service *k*, in period *t*	watt	(W)
$P^{i}_{DR\_A(l,k,t)}$	–	*DR_A* active power reduction, for load *l* at bus *i*, in service *k*, in period *t*	watt	(W)
$P^{w}_{DR\_A(l,k,t)}$	–	*DR_A* active power reduction, for load *l* which belongs to the region *w*, in service *k*, in period *t*	watt	(W)
$P^{z}_{DR\_A(l,k,t)}$	–	*DR_A* active power reduction, for load *l* which belongs to the region *z*, in service *k*, in period *t*	watt	(W)
$P_{DR\_AMax(l,k,t)}$	–	*DR_A* maximum active power reduction, for load *l*, in service *k*, in period *t*	watt	(W)
$P_{DR\_B(l,k,t)}$	–	*DR_B* active power curtailment, for load *l*, in service *k*, in period *t*	watt	(W)
$P^{i}_{DR\_B(l,k,t)}$	–	*DR_B* active power curtailment, for load *l* at bus *i*, in service *k*, in period *t*	watt	(W)
$P^{w}_{DR\_B(l,k,t)}$	–	*DR_B* active power curtailment, for load *l* which belongs to the region *w*, in service *k*, in period *t*	watt	(W)
$P^{z}_{DR\_B(l,k,t)}$	–	*DR_B* active power curtailment, for load *l* which belongs to the region *z*, in service *k*, in period *t*	watt	(W)
$P_{DR\_BMax(l,k,t)}$	–	*DR_B* maximum active power curtailment, for load *l*, in service *k*, in period *t*	watt	(W)
$P_{energy\_\lim it\_DG(DG,t)}$	–	Active power limit obtained by Bialek factors considering the energy dispatch, for distributed generation unit *DG*, in period *t*	watt	(W)
$P_{energy\_\lim it(r,t)}$	–	Active power limit obtained by Bialek factors considering the energy dispatch, for resources *r*, in period *t*	watt	(W)
$P_{energy\_\lim it\_SP(SP,t)}$	–	Active power limit obtained by Bialek factors considering the energy dispatch, for external suppliers *SP*, in period *t*	watt	(W)
$P_{energy\_RU\_\lim it\_DG(DG,t)}$	–	Active power limit obtained by Bialek factors considering the energy and Regulation Up dispatch, for distributed	watt	(W)

		generation unit *DG*, in period *t*		
$P_{energy\_RU\_limit(r,t)}$	–	Active power limit obtained by Bialek factors considering the energy and Regulation Up dispatch, for resources *r*, in period *t*	watt	(W)
$P_{energy\_RU\_limit\_SP(SP,t)}$	–	Active power limit obtained by Bialek factors considering the energy and Regulation Up dispatch, for external suppliers *SP*, in period *t*	watt	(W)
$P_{energy\_RU\_Spinning\_limit\_DG(DG,t)}$	–	Active power limit obtained by Bialek factors considering the energy, Regulation Up and Spinning reserve dispatch, for distributed generation unit *DG*, in period *t*	watt	(W)
$P_{energy\_RU\_Spinning\_limit(r,t)}$	–	Active power limit obtained by Bialek factors considering the energy, Regulation Up and Spinning reserve dispatch, for resources *r*, in period *t*	watt	(W)
$P_{energy\_RU\_Spinning\_limit\_SP(SP,t)}$	–	Active power limit obtained by Bialek factors considering the energy, Regulation Up and Spinning reserve dispatch, for external suppliers *SP*, in period *t*	watt	(W)
P_G	–	Vector of nodal generations	watt	(W)
$P_{GCP(DG,t)}$	–	Generation Curtailment Power by *DG* unit in period *t*	watt	(W)
$P^{i}_{GCP(DG,t)}$	–	Generation Curtailment Power by *DG* unit at bus *i*, in period *t*	watt	(W)
P_{Gi}	–	Active power generation in node *i*	watt	(W)
$P_{Gi(t)}$	–	Active power generation at bus *i* in period *t*	watt	(W)
P_{Gr}	–	Active power generation of resource *r*	watt	(W)
P_{gross}	–	Unknown vector of gross nodal flows	watt	(W)
P^{g}_{i}	–	Unknown gross nodal active power flow through node *i*	watt	(W)
P_{ij}	–	Active power flow in line *i-j*	watt	(W)
P^{g}_{ij}	–	Unknown gross line active flow in line *i-j*	watt	(W)
$P^{g(r)}_{ij}$	–	Unknown gross line active flow in line *i-j* of resources *r*	watt	(W)
$P^{g(SP)}_{ij}$	–	Unknown gross line active flow in line *i-j* of external supplier *SP* resource	watt	(W)
P_j	–	Actual total active flow through node *j*	watt	(W)

P_{j}^{g}	–	Unknown gross nodal active power flow through node *j*	watt	(W)
$P_{Load(l,t)}^{i}$	–	Active power demand of load *l* at bus *i* in period *t*	watt	(W)
$P_{loss(t)}$	–	Active power losses in period t	watt	(W)
$P_{Ly(i,j)}^{\max}$	–	Maximum active power flow established in line *y* that connect the bus *i* and *j*	watt	(W)
$P_{NSD(l,k,t)}$	–	Non-supplied demand for load l in commodity *k* in period *t*	watt	(W)
$P_{NSD(l,k,t)}^{i}$	–	Non-supplied demand for load *l* at bus *i* in commodity *k* in period *t*	watt	(W)
$P_{Rd(t)}$	–	Rigid demand for period *t*	watt	(W)
$P_{req\_\mathrm{limit}(l,k,t)}$	–	Active power demand of load *l* for ancillary services *k*, in period *t*	watt	(W)
$P_{req\_\mathrm{limit}(l,k,t)}^{i}$	–	Active power demand of load *l* at bus *i* for ancillary services *k*, in period *t*	watt	(W)
$P_{req\_\mathrm{limit}(l,k,t)}^{\max}$	–	Maximum active power demand of load *l* for ancillary services *k*, in period *t*	watt	(W)
$P_{req\_\mathrm{limit}(l,k,t)}^{z}$	–	Active power demand of load *l* which belongs to the region *z*, for ancillary services *k*, in period *t*	watt	(W)
$P_{S(r,k,t)}$	–	Resource r scheduled power, in commodity *k*, for period *t*	watt	(W)
$P_{S(r,k,t)}^{i}$	–	Resource r scheduled power, in commodity *k*, at bus *i* for period *t*	watt	(W)
$P_{S(r,k,t)}^{\max}$	–	Resource r maximum selling bid power, in commodity *k*, for period *t*	watt	(W)
$P_{S(r,k,t)}^{\min}$	–	Resource r minimum selling bid power, in commodity *k*, for period *t*	watt	(W)
$P_{S(r,k,t)}^{w}$	–	Resource r scheduled power, in commodity *k*, for period *t* in region *w*	watt	(W)
$P_{S(r,k,t)}^{z}$	–	Resource r scheduled power, in commodity *k*, for period *t* in region *z*	watt	(W)
$P_{SP(SP,k,t)}$	–	Active power acquired from supplier *SP* for each service *k*, in period *t*	watt	(W)
$P_{SP(SP,k,t)}^{i}$	–	Active power acquired from supplier *SP* at bus *i*, for each service *k*, in period *t*	watt	(W)
$P_{SP(SP,k,t)}^{w}$	–	Active power acquired from supplier *SP* which belongs to the region *z*, for each service *w*, in period *t*	watt	(W)

$P_{SP(SP,k,t)}^{z}$	–	Active power acquired from supplier *SP* which belongs to the region *z,* for each service *k*, in period *t*	watt	(W)
$P_{SPMax(SP,k,t)}$	–	Maximum active power of external supplier *SP* for service *k* in period *t*	watt	(W)
$P_{SPMin(SP)}$	–	Total minimum active power of external supplier *SP*	watt	(W)
$P_{SP\,\mathrm{Rem}(SP)}$	–	Total minimum remuneration of external supplier *SP*	monetary unit	(m.u.)
$P_{SPVar(SP)}$	–	Generation variation of external supplier *SP* between periods	watt	(W)
$Q_{b(l,t)}^{i}$	–	Load *l* scheduled reactive power at bus *i*, for period *t*	volt-ampere reactive	(VAr)
$Q_{DG(DG,k,t)}$	–	Reactive power generation of distributed generation unit *DG* for service *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{DG(DG,k,t)}^{i}$	–	Reactive power generation of distributed generation unit *DG* at bus *i* for service *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{DGMax(DG,k,t)}$	–	Maximum reactive power generation of distributed generation unit *DG* for service *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{DGMin(DG,k,t)}$	–	Minimum reactive power generation of distributed generation unit *DG* for service *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{Di(t)}$	–	Reactive power demand at bus *i* in period *t*	volt-ampere reactive	(VAr)
$Q_{Gi(t)}$	–	Reactive power generation at bus *i* in period *t*	volt-ampere reactive	(VAr)
$Q_{Load(l,k,t)}^{i}$	–	Reactive power demand of load *l* at bus *i* for commodity *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{NSD(l,k,t)}^{i}$	–	Reactive non-supplied demand for load *l* in commodity *k* in period *t*	volt-ampere reactive	(VAr)
$Q_{S(r,k,t)}$	–	Resource r scheduled reactive power, in commodity *k*, for period *t*	volt-ampere reactive	(VAr)
$Q_{S(r,k,t)}^{i}$	–	Resource r scheduled reactive power, in commodity *k*, at bus *i* for period *t*	volt-ampere reactive	(VAr)
$Q_{S(r,k,t)}^{\max}$	–	Resource r maximum selling bid reactive power, in	volt-ampere	(VAr)

		commodity *k*, for period *t*	reactive	
$Q^{\min}_{S(r,k,t)}$	–	Resource r minimum selling bid reactive power, in commodity *k*, for period *t*	volt-ampere reactive	(VAr)
$Q_{SP(SP,k,t)}$	–	Reactive power acquired from supplier *SP* in service *k* in period *t*	volt-ampere reactive	(VAr)
$Q^{i}_{SP(SP,k,t)}$	–	Reactive power generation of external supplier *SP* at bus *i*, for service *k*, in period *t*	volt-ampere reactive	(VAr)
$Q_{SPMax(SP,k,t)}$	–	Maximum reactive power of external supplier *SP* in service *k* in period *t*	volt-ampere reactive	(VAr)
$R_{AS(k,t)}$	–	Ancillary service commodity *k* active power requirement, for period *t*	watt	(W)
$R^{\max}_{AS(k,t)}$	–	Ancillary service commodity *k* maximum required power, for period *t*	watt	(W)
$R^{\min}_{AS(k,t)}$	–	Ancillary service commodity *k* minimum required power, for period *t*	watt	(W)
$R^{z}_{AS(k,t)}$	–	Ancillary service in region *z* for commodity *k* active power requirement, for period *t*	watt	(W)
$R^{\max;\ z}_{AS(k,t)}$	–	Ancillary service in region *z* for commodity *k* maximum required power, for period *t*	watt	(W)
$R^{\min;\ z}_{AS(k,t)}$	–	Ancillary service in region *z* for commodity *k* minimum required power, for period *t*	watt	(W)
$RLXD_{(k,t)}$	–	Commodity *k* relaxation down variable to apply violation penalties, for period *t*	watt	(W)
$RLXD_{(z,k,t)}$	–	Relaxation down variable to apply violation penalties in each identified region *z*, for each ancillary service *k*, in period *t*	watt	(W)
$RLXU_{(k,t)}$	–	Commodity *k* relaxation up variable to apply violation penalties, for period *t*	watt	(W)
$RLXU_{(z,k,t)}$	–	Relaxation up variable to apply violation penalties in each identified region *z*, for each ancillary service *k*, in period *t*	watt	(W)
$SLCK^{RU\_NS}_{(t)}$	–	Amount of power which can be transferred from Regulation Up to Non-Spinning reserve, for period *t*	watt	(W)
$SLCK^{RU\_SP}_{(t)}$	–	Amount of power which can be transferred from Regulation Up to Spinning Reserve, for period *t*	watt	(W)

$SLCK^{SP\_NS}_{(t)}$	–	Amount of power which can be transferred from Spinning Reserve to Non-Spinning reserve, for period *t*	watt	(W)
$SLCK^{RU\_NS}_{(z,t)}$	–	Amount of power which can be transferred from Regulation Up to Non-Spinning reserve, in each region *z* for period *t*	watt	(W)
$SLCK^{RU\_SP}_{(z,t)}$	–	Amount of power which can be transferred from Regulation Up to Spinning Reserve, in each region *z* for period *t*	watt	(W)
$SLCK^{SP\_NS}_{(z,t)}$	–	Amount of power which can be transferred from Spinning Reserve to Non-Spinning reserve, in each region *z* for period *t*	watt	(W)
$S^{\max}_{Ly}$	–	Maximum apparent power flow established in line *y* that connect the bus *i* and *j*	volt-ampere	(VA)
T	–	Total number of periods	-	-
$\overline{U_{i(t)}}$	–	Voltage at bus *i* in polar form in period *t*	volt	(V)
$\overline{U_{j(t)}}$	–	Voltage at bus *j* in polar form in period *t*	volt	(V)
$X_{AS(r,k,t)}$	–	Resource *r* commitment binary variable, in ancillary service commodity *k*, for period *t*	-	-
$X_{DG(DG,k,t)}$	–	Binary variable of distributed generation unit *DG* related to accept the power generation in service *k*, in period *t*	-	-
$X_{DGMax(DG)}$	–	Maximum entries in service of distributed generation unit *DG* in time horizon *T*	-	-
$X_{DGMin(DG)}$	–	Minimum of period's *t* in functioning of distributed generation unit *DG* in time horizon *T*	-	-
$X_{DR\_B(l,k,t)}$	–	Binary variable for load curtailment *l*, in service *k*, in period *t*	-	-
$X_{L(l,t)}$	–	Load *l* commitment binary variable, for period *t*	-	-
$X_{S(r,k,t)}$	–	Resource *r* commitment binary variable, in ancillary service commodity *k*, for period *t*	-	-
$X_{S(S,t)}$	–	Binary variable of storage *S* to power discharge, in period *t*	-	-
$X_{SPMax(SP)}$	–	Maximum entries in service of external suppliers *SP* in time horizon *T*	-	-
$X_{SPMin(SP)}$	–	Minimum of period's *t* in	-	-

		functioning of external supplier *SP* in time horizon *T*		
$V_{i(t)}$	–	Voltage magnitude at bus *i* in period *t*	volt	(V)
$V_{i(t)}^{\max}$	–	Maximum voltage magnitude at bus *i*	volt	(V)
$V_{i(t)}^{\min}$	–	Minimum voltage magnitude at bus *i*	volt	(V)
$V_{j(t)}$	–	Voltage magnitude at bus *j* in period *t*	volt	(V)
$W_{RLXD(k,t)}$	–	Relaxation down penalty of commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$W_{RLXD(z,k,t)}$	–	Relaxation down penalty of region *z*, in commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$W_{RLXU(k,t)}$	–	Relaxation up penalty of commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$W_{RLXD(z,k,t)}$	–	Relaxation up penalty of region *z*, in commodity *k*, for period *t*	monetary unit per watt	(m.u./W)
$Y_{S(S,t)}$	–	Binary variable of storage *S* related to power charge, in period *t*	-	-
$\overline{y_{ij}}$	–	Series admittance of line that connect the bus *i* and *j* in polar form	siemens	(S)
$\overline{y_{Sh\_i}}$	–	Shunt admittance of line connected in the bus *i* in polar form	siemens	(S)

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Chapter 1

Introduction

1. Introduction

This chapter exposes the motivation, the objectives and the contribution of the work developed in the scope of this dissertation. The importance of ancillary services in the context of the present and future power systems is explained.

Here it is also presented how the dissertation is organized, as well as its contribution to the field of study.

1.1. Background and Motivation

The restructuring and consequent deregulation of the electricity sector imposes new methodologies in the operation and management of Power Systems (PS) [Shahidehpour-2002]. Therefore, the collaboration between regions and countries is increasingly crucial for the proper functioning of the overall electricity market. In the last decade, there has been a continued restructuring of competitive electricity markets based on the electricity sector's restructuring process, which introduced a new paradigm in its functioning, particularly in terms of generation and trading, which began to unfold in a competitive environment. Thus, the electricity started to be seen as a marketable product resulting in a set of transactions between players, managed by coordination entities, namely the Market Operator (MO) and System Operator (SO) and regulatory authorities which supervise the functioning of the system [Gomes-2007, Shahidehpour-2002].

In this context, to guarantee the good functioning of power systems in a market environment, adequate Ancillary Services (AS) requirements must be defined. Throughout their existence, ancillary services have been defined in several different ways in the USA and in Europe according to the evolution of power systems. In 1995 Kirby *et al.* defined ancillary services as *"those functions performed by the electrical generating, transmission, system-control, and distribution system equipment and people that support the basic services of generating capacity, energy supply, and power delivery"* [Kirby-1995]. In the same year, the Federal Energy Regulatory Commission (FERC) defined ancillary services as "*those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system*" [FERC-1995]. In 2000, EURELECTRIC stated that ancillary services are "*those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser*" [EURELECTRIC-2000]. A few years later, the same EURELECTRIC established a definition for AS accepted by most of the countries and the wider scientific community: "*Ancillary services are all services required by the transmission or distribution system operator to enable them to maintain the integrity* *and stability of the transmission or distribution system as well as the power quality"* [EURELECTRIC-2004, Braun-2007].

Multiple ways to classify the AS have been developed. The more general AS classification is based on systems needs in terms of operating requirements. The system needs of each ancillary service are determined by the Independent System Operator (ISO) in accordance with specific system operation standards of the market [EURELECTRIC-2000]. AS are classified into three distinct categories of their contribution to specific system requirements, as illustrated in Figure 1.1.

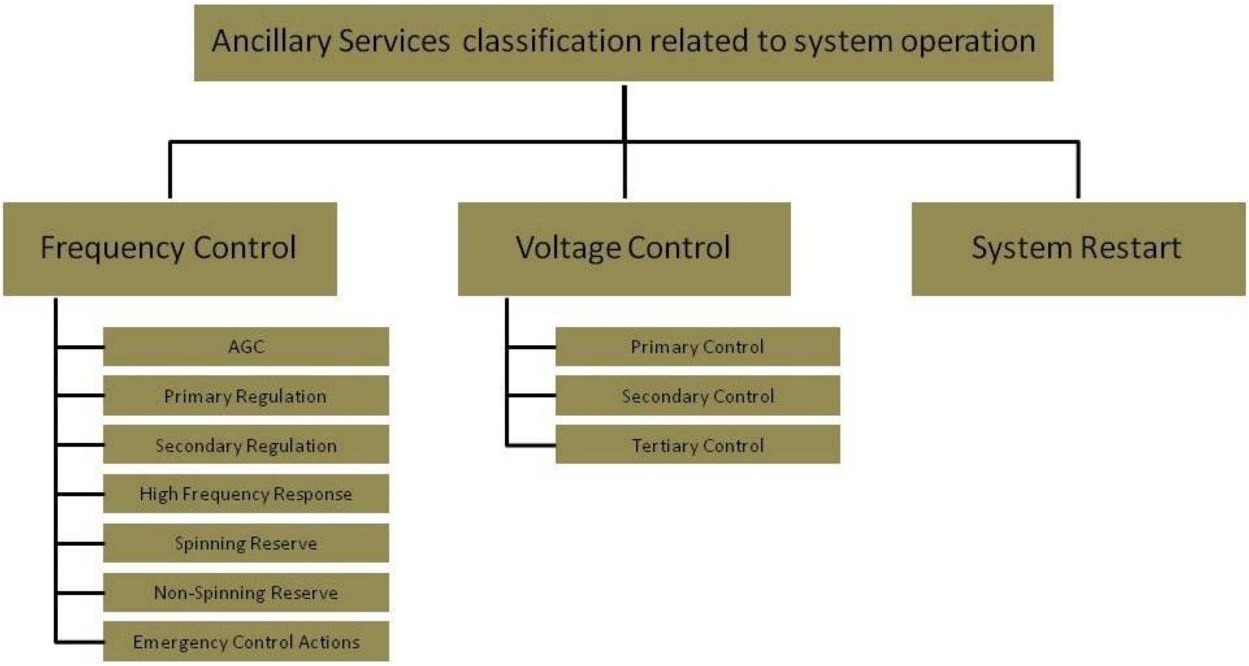

Figure 1.1 – Ancillary services classification [EURELECTRIC-2000].

The frequency control consists in maintaining the frequency within the given margins by continuous modulation of active power and it can be obtained through the following ancillary services [EURELECTRIC-2000, EURELECTRIC-2004]: Automatic Generation Control; primary regulation; secondary regulation; high frequency response; spinning reserve, non-spinning reserve; and emergency control auctions.

The voltage control consists in maintaining voltage through injecting or absorbing reactive power by means of synchronous or static compensation. In general, the voltage control is organized into a three-level hierarchy [Rebours-2007]: primary, secondary, and tertiary voltage control.

The system restart consists in sufficient electricity sources that would be available to restart the power system after a partial or complete blackout. This is mainly obtained through the restoration capability which is the capability of a generation unit to start up without an external power supply [EURELECTRIC-2000, EURELECTRIC-2004].

During the restructuring of the electric sector around the world, several models of energy and AS markets have been developed. An aspect shared by several electricity markets is the existence of a system operator, which can be an ISO, a Transmission System Operator (TSO) or a Distribution System Operator (DSO), responsible for the reliable real-time operation and control of the transmission / distribution system which enables the efficient operation of a competitive energy and AS market [Oren-2001, Papalexopoulos-2001].

Currently, some electricity markets have been adopting the concept of optimizing the energy market jointly with the AS market. This optimization model is often called as the energy and AS joint market. This model, comparing with the traditional model, promotes economic efficiency of the market reaching to interesting results [Soares-2011]. However, the joint model used in the real markets does not guarantee a feasible solution. The main problem is that the model do not consider the impact that the AS may have on network congestion.

In this context, it becomes essential to develop methodologies to solve the problem in order to ensure the smooth operation of the system. The methodologies should ensure the feasibility and reliability of the system and guarantee the quality of power service within the parameters defined in each market.

An approach that may partially solve the feasibility of the energy and AS joint market is the AS procurement by areas/regions of the network. The consideration of AS procurement by network regions allows acquiring and ensuring AS with higher quality at all points of the network, especially in consumer locations distant from the point of energy generation. In this way, the regional AS procurement is an approach that may results in more efficient distribution of reserves, in order to improve the reliability in the event of a contingency occurring anywhere in the system [Wu-2004].

An approach to solve the problem of feasibility of the energy and AS joint market is the use of distribution factors (namely the Bialek topological distribution factors) to limit the energy production of generation units that may cause congestion on the network lines. This approach involves a complex, sequential and hierarchical analysis of the ancillary services traded in the market. This approach presents feasible results of the system, avoiding any network congestion which may occur in traditional approaches.

Based on these assumptions, the operation of electricity and AS markets can considers different models which determine the course of action of the players involved. Thus, these models are crucial for the strategic management of sellers and buyers who operate within each market, particularly for the spot market [Vale-2011]. Decisions on bids to be submitted must be supported by adequate decision support systems, such as MASCEM – a Multi-Agent Simulator of Competitive Electricity Markets or EMCAS – Electricity Market Complex Adaptive System. These systems are based on simulation and they must be able to model the complex and dynamic nature of the energy and AS market, as well as the players who act in them, how they interact and how they react to the rules used and to the actions of other players [Praça-2003, Pinto-2011a]. Furthermore, market simulation systems must increasingly take into account the players related to new concepts of generation and operation in the scope of the Smart Grid (SG) paradigm. In this context, power systems have experienced many changes, mainly due to the increasing introduction of Distributed Energy Resources (DER) [Thong-2007, Scalari-2008], namely Distributed Generation (DG) [Morais-2010a], storage units, Electrical Vehicles (EV) with gridable capability (V2G) [Sousa-2011, Luo-2012] and Demand Response (DR) [Schisler-2008, Faria-2011]. The introduction of this kind of resources in the distribution systems requires new management and new operation methods because the methodologies currently used are not able to deal with the challenges resulting from the new paradigm in distribution systems operation. In this way, a wide variety of resources may be useful to enable a more efficient resources' management by the ISO, DSO and /or Virtual Power Players (VPP) in the demand supply. Moreover, the DER may be useful at the AS provision level. That is, DER may participate at a controlled cost in specific conditions, like when there is surplus or shortage generation in the power system balance.

VPPs that aggregate a set of resources in a given network zone, including DG based on renewable sources, storage systems, DR and EV, are very relevant players that allow midsize, small and micro players to act in a competitive environment of energy and AS markets [Pinto-2011a, Vale-2010].

The VPP will play a major role in the context of SG, aggregating a set of resources with the objective of maximizing their value and the aggregated players' profit.

Figure 1.2 illustrates the VPP concept and its possible services from a technical and a market standpoint. A variety of DER dispersed throughout the distribution network is combined via communication networks by an aggregator within the framework of a VPP. A set of services can be provided comprising the participation on electricity markets, as well as the AS provision.

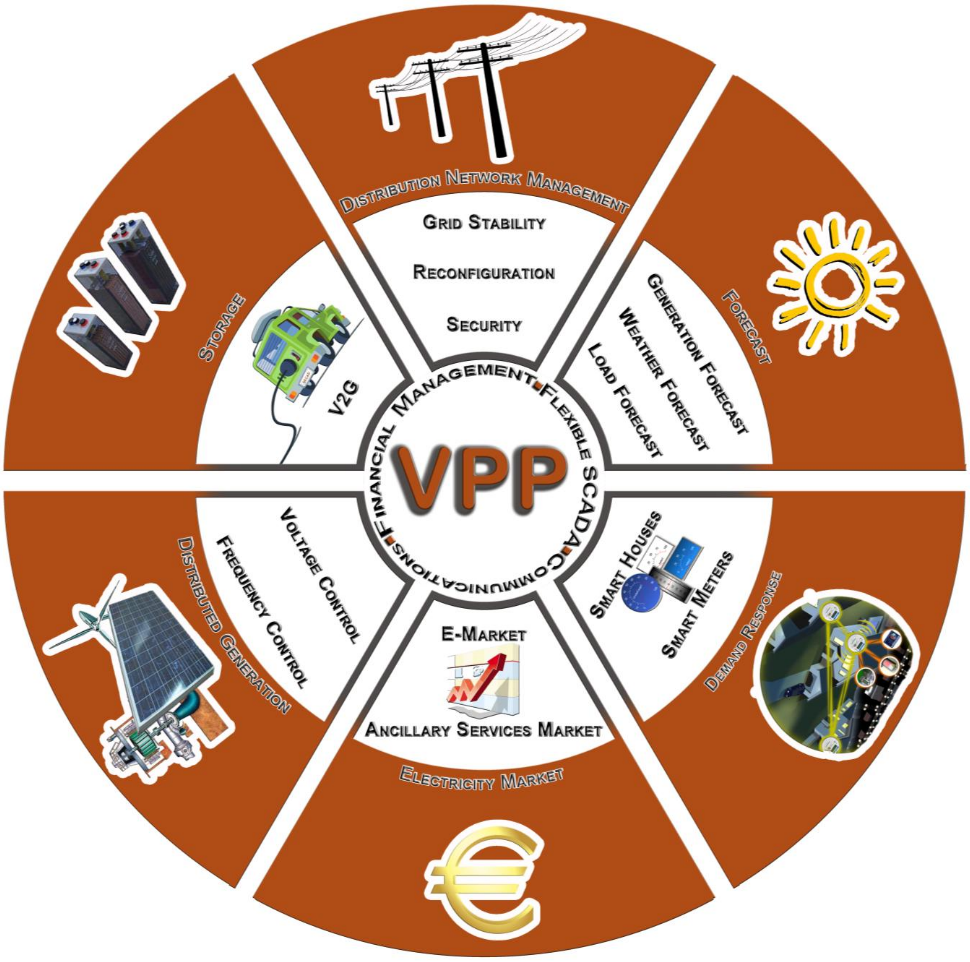

Figure 1.2 – The VPP concept from a technical and market standpoint [Morais-2010b].

In the new paradigm of power systems operation, ISO will consider the existence of VPPs able to aggregate all kind of small size distributed energy resources, which are unable to individually engage themselves on the market. This implies that the AS procurement by the VPP is targeted to the distribution systems. Thus, the VPP should consider the establishment of complex contracts with the DER in order to ensure reserves levels and quality of AS appropriate to the needs of the distribution system.

In this context, the operation and control of future distribution network and smart grid is expected to use the following ancillary services provided by the DSO or by the VPP: Frequency Control; Voltage Control; Congestion Management; Optimization of Grid Losses and Fault-Ride-Through Capability service [Braun-2007, Buehner-2010]. The Fault-Ride-Through Capability service is characterized by the use of this kind of resources through the VPP management to provide voltage support in case of voltage disturbances in order to improve the reliability of supply, resulting in an increase of the power quality levels.

This dissertation presents a work that addresses some of the AS problems mentioned in this subchapter, and it contributes to the continuous development of existing and new AS market paradigms.

One important point is the development of AS market methodologies, as well as the energy and AS joint market based on realistic models. Another important point is the development of an innovative methodology to solve the problem of network congestion caused by the joint market approach. The inclusion of AS procurement by regions of the network is other important approach to solve the network congestion and improve the system reliability.

A main contribution of the work lies on the distribution network AS management by a VPP, considering a large penetration of DER. The approach includes complex contracts between the VPP and the DER so that these resources may participate in local AS management, as well as in AS market.

The inclusion of the proposed and implemented methodologies in the MASCEM simulator is a additional contribution of the work.

Another benefit of the work is the inclusion of several perspectives of system analysis, namely ISO, TSO, DSO and VPP in order to integrate the SG paradigm with large penetration of DER.

1.2. Objectives

The present and future of power systems depends heavily on the ability of energy and AS markets in dealing with the challenges, which have arisen in a competitive environment context. The continuous introduction of DER in the energy market through VPPs, as well as the energy policies adopted by each country/region, can result in a considerable differentiation of the market functioning for each country. This implies the need to conduct a continuous development of AS market methodologies in order to ensure the smooth operation of the power system.

In this context, this dissertation offers a huge contribution in AS market simulation, based on models and mechanisms used nowadays by many real markets, as well as the introduction of new methodologies on energy and AS joint market simulation. The consideration of several perspectives of AS market management (namely, in the ISO, TSO, DSO and VPP standpoint) is also a contribution of this dissertation.

In the context of energy and AS joint market simulation, the specific objectives defined for this dissertation were the following:

- Research, design and development of real AS market and energy and AS joint market model;
- Integration of AS bidding regions mechanism in energy and AS joint market in order to improve the system reliability;

- Development of a innovative methodology in energy and AS management based on the distribution factors, in order to solve network congestion problems;
- Design and development of a distribution network AS management methodology considering a large penetration of DER. Inclusion of AS management in a DSO and VPP standpoint;
- Establishment of complex contracts between the VPP and the DER in order to DER participate in local AS management, as well as in AS market;
- Inclusion of all proposed and implemented methodologies in the MASCEM market simulator.

1.3. Related Projects and Publications

The work developed in the scope of this dissertation partially concerns the objectives and results of several projects developed in GECAD – the Knowledge Engineering and Decision Support Research Center. The projects are:

- ViP-DiGEM - VIrtual power Producers and DIstributed Generation trading in Energy Markets (PTDC/ENR/72889/2006);
- ID-MAP - Intelligent Decision Support for Electricity Market Players (PTDC/EEA-EEL/099832/2008);
- FIGURE – Flexible and Intelligent Grids for Intensive Use of Renewable Energy Sources (PTDC/SEN-ENR/099844/2008);
- IMaDER – Intelligent Short Term Management of Distributed Energy Resources in a Multi-Player Competitive Environment (PTDC/SEN-ENR/122174/2010).

The developed work has resulted in several scientific papers, some of which have already been published, accepted for publication and/or are under revision. The following should be referred:

- Tiago Soares, Hugo Morais, Bruno Canizes, Zita Vale, "Energy and Ancillary Services Joint Market Simulation", EEM11 - 8th International Conference on the European Energy Market, pp. 262-267, Zagreb, Croatia, 25- 27 May, 2011.
- Tiago Soares, Hugo Morais, Pedro Faria, Zita Vale, "Smart Grid Market Using Joint Energy and Ancillary Services Bids", IEEE PowerTech, Grenoble, France, 16-20 June, 2013.
- Tiago Soares, Gabriel Santos, Pedro Faria, Tiago Pinto, Zita Vale, Hugo Morais, "Integration in MASCEM of the joint Dispatch of Energy and Reserves Provided by Generation and Demand Resources", IEEE ISAP2013 – 17th

International Conference on Intelligent Systems Applications to Power Systems, Tokyo, Japan, 1-4 July, 2013.

- Tiago Soares, Hugo Morais, Zita Vale, "Energy and Ancillary Services Joint Market Considering Different Bidding Regions" Under revision.
- Hugo Morais, Tiago Soares, Pedro Faria, Zita Vale, "VPP Energy Resource Management in Microgrids Considering Complex Contracts", Under revision.

1.4. Organization of the Dissertation

This dissertation is organized into five chapters. In addition to the present introductory chapter, the structure of this dissertation includes four other chapters which are described in the following topics:

Chapter 2 exposes the design of real markets used in some countries/regions, namely BETTA, CAISO, Nord Pool and MIBEL markets. In this context, Day-Ahead Market (DAM), Real-Time Market (RTM) and Ancillary Service Market (ASM) are addressed, in order to expose and analyze in detail the intrinsic rules of each kind of market in the respective country/region. The AS market models adopted by each country are idealized according to the particular needs and characteristics of each one. In this way, this chapter comprises a good description of the AS market operation in each country, in order to realize the most significant differences between the models studied. At the end of the chapter, a concise yet well-founded comparison of the ancillary services markets studied is presented.

Chapter 3 presents an assessment of several problems related to energy and ancillary services markets. In that chapter, one can find the theoretical basis for solving the optimization problems of the energy and AS joint market. Besides the presentation of the models studied based on real markets, a new method for solving the joint market is proposed.

Chapter 4 presents a set of case studies concerning the models presented in the previous chapter. The presented case studies are based on real data regarding the AS bids submitted to the ancillary service market. The last case study is based on a distribution network with high penetration of DER, namely DG, storage units, and DR. The obtained results are presented and individually discussed for each problem.

Chapter 5 presents the most important conclusions that resulted from the work developed. Also here, some future work is proposed.

Chapter 2

Ancillary Services Markets Overview

2. Markets Overview

In the last decade, the electricity markets evolved under the concept of liberalization in a competitive environment and allowing the evolution of the Power Systems (PS) operation [Shahidehpour-2002]. The Electricity markets have as main goal the improvement of the electricity service efficiency provided to consumers [Kirschen-1997]. Such liberalized markets have a high impact on the actual transmission/distribution networks, obtaining a reduction of blackouts and a faster response to replace the electrical system promoting economic efficiency [Mannila-2000].

This chapter presents the structure of the liberalized market in some countries/states/regions considered the most interesting from the point of view of this thesis. In this way, the chapter also provides a succinct overview of the functioning of the United Kingdom (BETTA /N2EX), California (CAISO), Nordic (Nord pool) and Iberian (MIBEL) electricity markets.

2.1. BETTA / N2EX

The United Kingdom was one of the first countries to restructure its electricity industry. Under the terms of the Electric Act of 1989, the state-owned Central Electricity Generating Board (CEGB) was divided into the National Grid Company (NGC), responsible for transmission, and three generating companies [Heffner-2007].

The British Electricity Trading and Transmission Arrangements (BETTA) is the current British electricity market system, which began operating in April 2005 replacing the previous New Electricity Trading Arrangements (NETA) in England and Wales, and the separate arrangements that existed in Scotland and the British Grid System Agreement (BGSA). The present market model has a single System Operator (SO) – the NGC – and includes three separate companies owning broadcasting licenses, in particular, the NGC, Scottish Power and the Scottish Hydro. Thus, the NGC has a dual function, the owner of a part of the transmission network and the SO function. In this way, the national regulator must ensure that the NGC as the SO does not discriminate the other companies owners of the remaining part of the transmission network for the NGC benefit [Gomes-2007].

BETTA power market is strictly an energy commodity market made up of four distinct submarkets. The first one is the forward and future market which accommodates long-term bilateral contracts that extend from months to years ahead. The second is a short-term bilateral contracts market which consists in day-ahead trading of bilateral contracts. The third is a balancing mechanism which is the UK real-time market and finally the fourth submarket is a small imbalance market which contemplates the settlement of cash flows arising from the balancing process. BETTA market structure and its respective stages are represented in Figure 2.1.

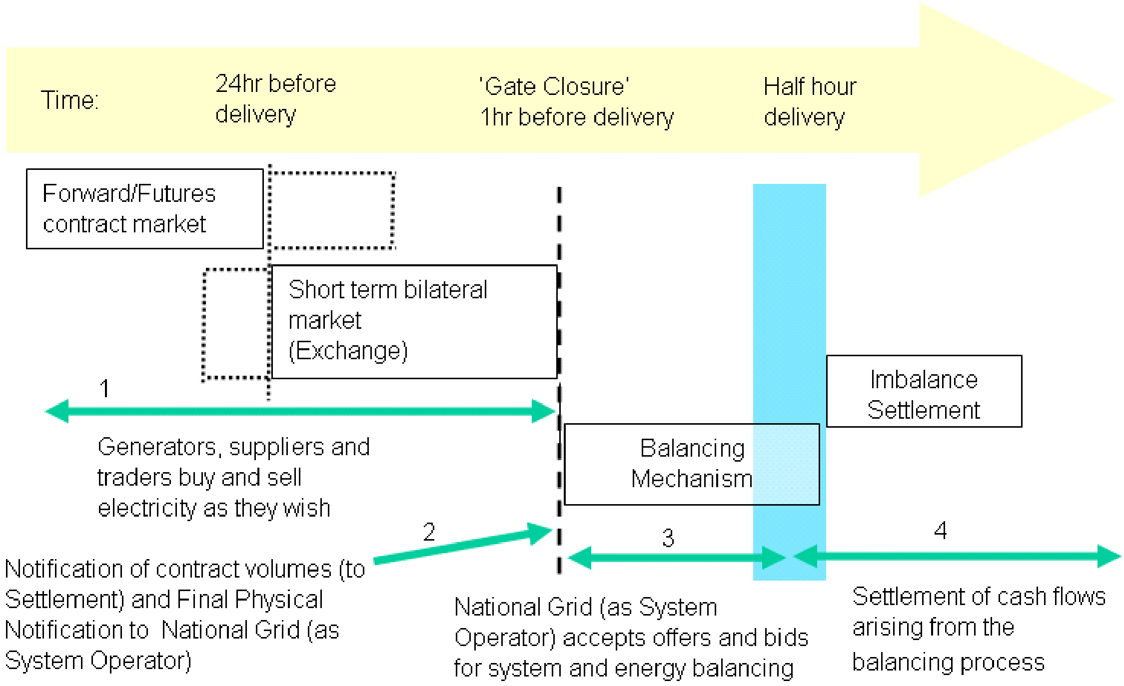

Figure 2.1 – BETTA market structure overview [NGET-2012a].

Currently, over 90% of the wholesale electricity market is bought and sold by bilateral contracts between buyers and sellers in over-the-counter markets or in power exchanges such as the N2EX. The N2EX is the name of the market for United Kingdom energy contracts operated by NASDAQ OMX Commodities and Nord Pool Spot. The NASDAQ OMX Clearing is the authorized clearinghouse of the N2EX market [N2EX-2012]. The market was launched in January 12th 2010 and comprehends the United Kingdom physical power market solution, including technical trading and clearing, a regulatory framework, as well as the clearing market procedures and ELEXON approvals of clearinghouse requirements. ELEXON is the Balancing and Settlement Code (BSC) Company established under the provisions of the BSC. ELEXON establishes the rules and governance arrangements for electricity balancing and settlement in UK and also is responsible for ensuring its proper, effective and efficient implementation [NGET-2012a]. In N2EX spot market, the physical market is jointly operated by Nord Pool Spot and NASDAQ OMX Commodities, while the futures market is operated by NASDAQ OMX Commodities. The N2EX power market can be divided into three submarkets [N2EX-2012]:

- The spot market – A continuous market for half-hour contracts, 1-hour contracts, 2-hour blocks and 4-hour blocks, overnight, block 3+4, peak, off-peak, extended peak and base;
- The prompt market – A prompt market for physically delivered power providing 4-hour blocks, overnight, block 3+4, peak, off-peak, extended peak

and base, weekend and weekly contracts for peak and base load. Identical contracts in the prompt and spot markets will be moved from the prompt market to the spot market at the closing of the prompt market at 07 p.m. on Fridays or two days prior to the beginning of the delivery period to avoid overlapping contracts;

- The Day Ahead Market – A day-ahead spot market auction for physically delivered power.

2.1.1. Forward and Futures Contract Markets

The forward and futures contract markets (see Figure 2.1) consist of bilateral contracts markets for firm delivery of electricity which operates from a year or more ahead the real-time up to 24 hours ahead of the delivery. The markets provide the opportunity for a seller and buyer 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 forward and futures contract market is intended to reflect the electricity trading over extended periods and it 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 the delivery ("the gate closure") [Heffner-2007, NGET-2012a].

2.1.2. Short-term Bilateral Markets

The Power Exchanges can operate over similar Forward and Futures contract markets timescales, however trading tends to be concentrated in the last 24 hours as shown in Figure 2.1. The markets can be fit to the form of exchanges in which participants trade a series of standardized blocks of electricity. The power exchanges enable sellers and buyers 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 power exchanges [Heffner-2007, NGET-2012a].

2.1.3. Balancing Mechanism

The Balancing Mechanism operates from Gate Closure through real-time (as can be seen in Figure 2.1) and is managed by the NGC. It was created to ensure that supply and demand can be continuously matched or balanced in real-time. The mechanism is operated with the SO acting as the sole counter party to all transactions. Participation in the balancing mechanism is optional and involves submitting offers and/or bids. This mechanism operates on a "pay as bid" basis. NGC purchase offers, bids, ancillary services and other balancing services to match supply and demand, to resolve transmission constraints and thereby balance the system. As part of this process, NGC must ensure that the system is run within operational standards and limits. In order to ensure that the security of supply is effectively and efficiently maintained, the NGC is able to assess the physical position of market participants. Therefore, all market participants are required to inform NGC of their planned net physical flows to the system. Initial Physical Notifications (IPN) are submitted at 11 a.m. of the day-ahead process. These are continually updated until the Gate Closure when they become the Final Physical Notifications (FPN) [Heffner-2007, NGET-2012a].

The balancing services include Ancillary Services (AS), offers and bids made in the balancing mechanism, and other services available to the NGC which can be used to assist it in the transmission system operation in accordance with the Electricity Act 1989.

2.1.3.1. Ancillary Services

Ancillary Services are part of the Balancing Mechanism and are procured from the authorized electricity operators, who own and operate generators, and other commercial entities, generally load customers or aggregators with backup generators and demand response resources.

According to [Heffner-2007, NETS-2011, NGET-2012a, NGET-2012b], the AS that are procured by the NGC are the Frequency Response, Regulating Reserve, Fast Reserve, Standing Reserve, Warming Reserve and Hot Standby Reserve.

- Frequency Response – System Frequency is determined by the balance between aggregate system demand and total generation in real-time. Frequency falls when the demand is greater than the generation and rises when the generation is greater than the demand. Frequency Response is the first AS used to compensate system frequency deviations. This service operates in real-time in a response time between 1 and 30 seconds. Basically there are two types of frequency response: the Dynamic Frequency Response which is a continuously provided service used to manage the normal second by second changes on the system, and Non-Dynamic Frequency Response which is usually a discrete service triggered at a defined frequency deviation;
- Regulating Reserves – are provided by generation units, controlled by the system operator that can increase or decrease the generators power output on a second-by-second basis;
- Fast Reserve – provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, by receiving an electronic dispatch instruction from NGC. This service can be supplied by generators and loads, if they meet the

following technical requirements: have the capability to delivery within 2 minutes of instruction; have the delivery rate greater than or equal to 25 MW/minute; be able to hold output for at least 15 minutes; deliver minimum 50MW for a single instructable unit or aggregation of more than one unit;

- Standing Reserve currently defined by the National Grid as "Short Term Operating Reserve" – consists in extra power in the form of either generation or demand to deal with actual demand being greater than forecast demand or generation less than forecast due to plant breakdowns. This requirement is met from synchronized and non-synchronized sources. The service provider must be able to: offer a minimum of 3MW or more of generation or steady demand reduction; deliver full MW within 240 minutes or less from receiving instructions from the National Grid; provide full MW for at least 2 hours when instructed; have a recovery period after provision of reserve of no more than 20 hours; be able to provide the service at least 3 times a week. This service contemplates two forms of payment: the Availability Payments which service providers are paid to make their unit/site available for the service within an availability window, and the Utilization Payments which the service providers are paid for the energy delivered as instructed by the National Grid, in which is included the energy delivered in ramping up to and down from the contracted MW level;
- Balancing Mechanism Start-Up Service – consists of a mechanism which allows NGC to access generation in the balancing mechanism that otherwise is not planned to run. The service replaces the Warming and Hot Standby services.
    - Warming Reserve – This service was established with the objective of allowing the NCG to access generation thermal plants that would not be available in the balancing mechanism because of their slow cold startup time. The main goal of this kind of reserve is to maintain an adequate operating margin as contingent reserves. The NCG offers "Warming" contractual arrangements to generators to facilitate their willingness to provide "energy readiness" capabilities that can be converted into timely energy, synchronized reserves or frequency response services. Load customers are also allowed to provide this service;
    - Hot standby Reserve – are required under certain conditions and useful when it is necessary to hold some generation in a "state of readiness" to generate at short term. Under these circumstances, fuel will be used or energy will be taken to maintain this "state of

readiness" capability so that it can be converted into timely energy, synchronized reserves or frequency response services. The main technical requirements that a generator must fulfill to participate in this service are the ability to take on warmth to reduce the time taken to synchronize within Balancing Mechanism timescales, and be able to maintain such a state of readiness to synchronize for an agreed period of time.

Briefly, the ancillary services system under the Grid Code [NETS-2011, NGET-2012b] can be divided into three distinct categories presented below. "Part1 System AS" are those AS which are required for system reasons and which must be provided by users in accordance with the connection conditions. Frequency Response and Reactive Power are the most common AS in this Part1. "Part2 System AS" are those optional services (Fast Reserve, black start capability) set out in the Grid Code, which the user has agreed to make available, under a bilateral agreement. "Commercial AS" is the third category of AS system and are constituted by other optional services (Balancing Mechanism Start-Up service) used by the National Grid Electricity Transmission (NGET) in the operation of the total system. These optional services are used if these have been agreed to be provided by a player under an AS agreement or under a bilateral agreement, with payment being dealt under an AS agreement or in the case of externally interconnected system operators or interconnector users under any other agreement.

2.1.3.2. Imbalance Settlement

The power flows are metered in real-time to determine the actual quantities of electricity produced and consumed at each location. The volumes of any imbalance between participants contractual positions and the actual physical flow is then determined.

Imbalance volumes are settled at System Buy Price (SBP) when the measured energy is less than the energy traded. On the other hand, the imbalance volumes are settled at System Sell Price (SSP) when the measured energy is higher than the energy traded [Heffner-2007, NGET-2012a].

2.2. CAISO

The California Independent System Operator (CAISO) is a non-profit organization subject to the Federal Energy Regulatory Commission (FERC) regulation. Throughout its existence, the original design of the California market has been continuously subject to a process of evaluation and restructuring in order to be improved. The design of the California market is a system that integrates four processes related to a Pre-Market, Day-Ahead Market (DAM), Real-Time Market (RTM), and a Post-Market based on nodal marginal pricing

[CAISO-2010]. The Pre-Market consists in the process of several activities in preparation for the DAM. Some of the key activities are related to annual Congestion Revenue Rights (CRRs) and to the update, test and release of the full network model, which contains all the intrinsic characteristics of the network. The activities of the Pre-Market and its characteristics are fully discussed in section 2.2.1. The DAM corresponds to a system which includes information of the transmission network allowing the CAISO to adjust the production and load programs, as well as imports and exports, alleviating any congestion of the transmission network, and ensuring their reliability. This process produces marginal prices for electricity at each node of the transmission network. The CAISO can assess whether the DAM program includes sufficient resources related production, to meet the forecast consumption for the next day and if inadequate, may dispatch other units. The Ancillary Services market runs simultaneously with the congestion management and the DAM process to obtain the operating reserves and required regulation [CAISO-2011a, CAISO-2011b]. The DAM is described in greater detail in section 2.2.2. The RTM runs every five minutes through a Real-Time Economic Dispatch (RTED) program including security constraints. This process determines the resources dispatch necessary to meet the mechanisms of real-time operation. In this market the nodal marginal energy prices are determined, which are paid to resources that generate energy. These prices can be used to calculate zonal prices for large geographical areas and paid by consumers covered entities [CAISO-2011a, CAISO-2011b]. In section 2.2.3 is approached with greater emphasis the RTM. The Validation of energy production and demand, as well as the LMP price correction are activities related to procedures of the Post-Market, presented and explained in section 2.2.5.

Figure 2.2 presents a high level description of the DAM and RTM including market bidding timelines and primary activities discussed in section 2.2.2 and 2.2.3.

2.2.1. Pre-Market

The Pre-Market includes various activities essential for the preparation of the DAM. The main activities are described as follows: the annual CRRs are financial instruments that may be used by their holders to offset the possible congestion charges that may arise in the DAM for energy. This process normally occurs TY-120 (Trading Year-120 days) days before the start of the current year and is settled based on the marginal cost of the congestion component of Locational Marginal Price (LMPs) from the Integrated Forward Market (IFM) [CAISO-2011a]. The full network model is reviewed, updated and tested every three weeks and consists in a representation of WECC (Western Electricity Coordinating Council) network model including the CAISO balancing authority area that enables the CAISO to produce a base market model to use as the basis for formulating the individual market models.

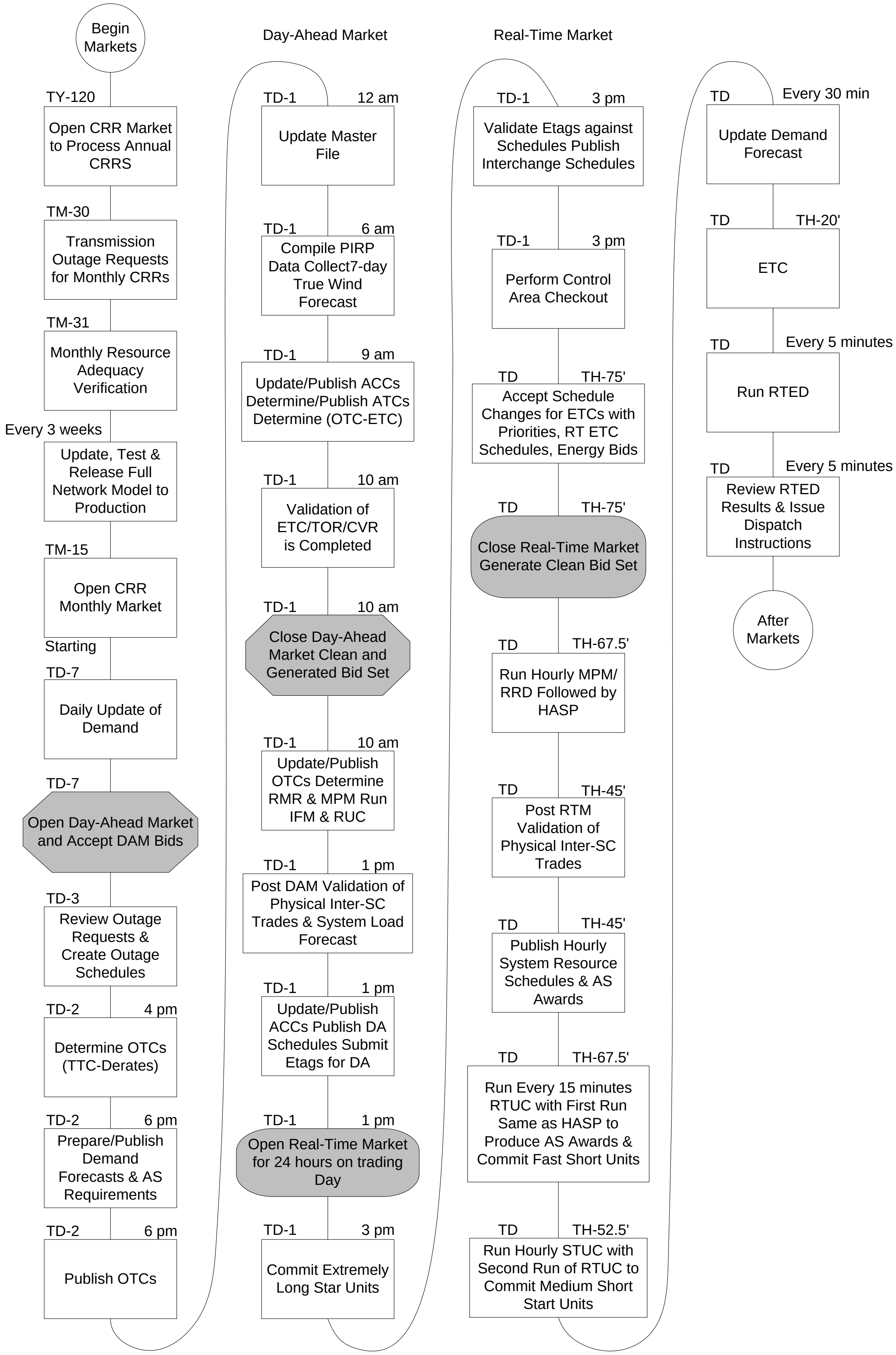

Figure 2.2 – CAISO market timeline overview [CAISO-2011a].

The full network model is used to conduct power flow analysis to manage transmission constraints for the optimization of each of the CAISO markets [CAISO-2011b]. The opening of the DAM occurs in the TD-7 (Trading Day-7 days) days, in which all DAM bids are accepted to participate in the DAM market. The pre-market ends in TD-1 until 10 a.m., in which all proposals are validated and published [CAISO-2011a]. The illustration of the pre-market process is shown in Figure 2.2.

2.2.2. Day-Ahead Market

The DAM design includes a system-wide optimization of resources which considers a large portion of supply necessary to meet the demand which has been self-scheduled as price-takers so that it is automatically scheduled in the DAM. The marginal supply needed to meet the demand is provided by resources that are bid into and scheduled through the market software [CAISO-2010]. This software optimizes the unit commitment and scheduling over a 24 hour period using a Mixed Integer Programming (MIP) algorithm with the objective of minimizing the total bid costs of resources committed and scheduled by the market software. In this optimization the generation units may submit start-up costs, minimum load costs and bids for energy above minimum operating levels. If a unit is started up or scheduled at minimum load during some hours of a day through the DAM, the unit is eligible for a bid cost recovery payment to ensure that it recovers the full cost of its start-up and minimum load costs, plus any energy bids that are dispatched. Furthermore, the market design also considers the co-optimization of energy and AS from resources that can provide both of these products, as well as the possibility of the AS cascade optimization which allows the substitution of the AS higher quality for the AS lower quality reserves if this is a more economic way to meet the minimum requirements for each ancillary service [CAISO-2011c]. For example, the regulation up may be procured in place of spinning reserve and/or non-spinning reserve, as well as the spinning reserve in place of non-spinning reserve, but never the opposite.

The Day-Ahead Market consists in several functions performed in sequence that determine the hourly Market Clearing Price (MCP) for energy and AS including physical and "virtual bids" (virtual bid is a bid submitted in the DAM which represents a commitment to receive revenues for energy at the LMP in the DAM and to make payments), as well as the incremental procurement in Residual Unit Commitment (RUC), while also determining Reliability Must-Run (RMR) dispatch levels to meet local reliability requirements and mitigating bids that may be in excess of local market power mitigation limits. In order to get the best day-ahead schedule at the lowest cost ensuring local reliability needs, these processes are co-optimized [CAISO-2011a, CAISO-2011b].

The Market Power Mitigation & Reliability Requirements Determination (MPM-RRD) is the first market process in the DAM, which consists of two combined processes that run simultaneously, the MPM and the RRD [CAISO-2011a]. The MPM function consists of a test to determine which bids are subject to mitigation for local market power based on criteria pre-specified by the CAISO. On the other hand, the RRD function determines the minimal and most efficient schedule of the RMR generation to address local reliability in meeting the CAISO forecast of CAISO demand for the next trading day, and to mitigate the submitted energy bids from RMR units if they are called to operate under a RMR contract [CAISO-2011a, CAISO-2011b].

The second market process in the DAM is the IFM that is a market for trading physical and virtual energy and AS for each trading hour of the next trading day [CAISO-2011a]. In accordance to [CAISO-2011b], the integrated forward market performs unit commitment and congestion management clears mitigated or unmitigated bids cleared in the first process, as well as bids that were not cleared in the first process against bid-in demand, taking into account transmission limits and honoring technical and inter-temporal operating constraints, such as minimum run times and procures AS to meet one hundred percent of the CAISO forecast of CAISO demand requirements. In the IFM is used a Security Constrained Unit Commitment (SCUC) algorithm that optimizes start-up costs, minimum load costs, transition costs and energy bids along with any bids for AS as well as self-schedules submitted by scheduling coordinators.

The RUC is the last market process in the DAM, which consists in a reliability function for committing resources and procuring RUC capacity not scheduled in the IFM. RUC capacity is procured in order to meet the difference between the CAISO forecast of CAISO demand and the demand scheduled in the IFM, for each trading hour of the trading day [CAISO-2011a]. In other words, the RUC process is designed to allow the CAISO to procure any additional unloaded capacity necessary to ensure that all projected energy requirements can be met in real time [CAISO-2010, CAISO-2011c]. This RUC capacity is selected by a SCUC optimization similarly to the one used in the IFM, adjusted to help ensuring the deliverability of the energy from the RUC capacity. Furthermore, RUC anticipates supply and demand over a longer look-ahead time period (default to 72 hours but it can be up to 168 hours, compared to 24 hours in the IFM). This allows RUC issue advisory commitment instructions for extremely long-start resources (example of traditional thermal power plants) which may not be considered in the IFM due to their long-start up times. In this way, the RUC objective is to ensure sufficient physical capacity that is available and committed at least cost to meet the adjusted CAISO forecast of CAISO demand for each hour of the next trading day, subject to transmission and resource operating constraints [CAISO-2011a, CAISO-2011b].

The prices resulting from these processes are used for the DAM settlement. The detailed DAM timeline is shown in Figure 2.3, showing the execution of the main market application functions (MPM-RRD, IFM and RUC).

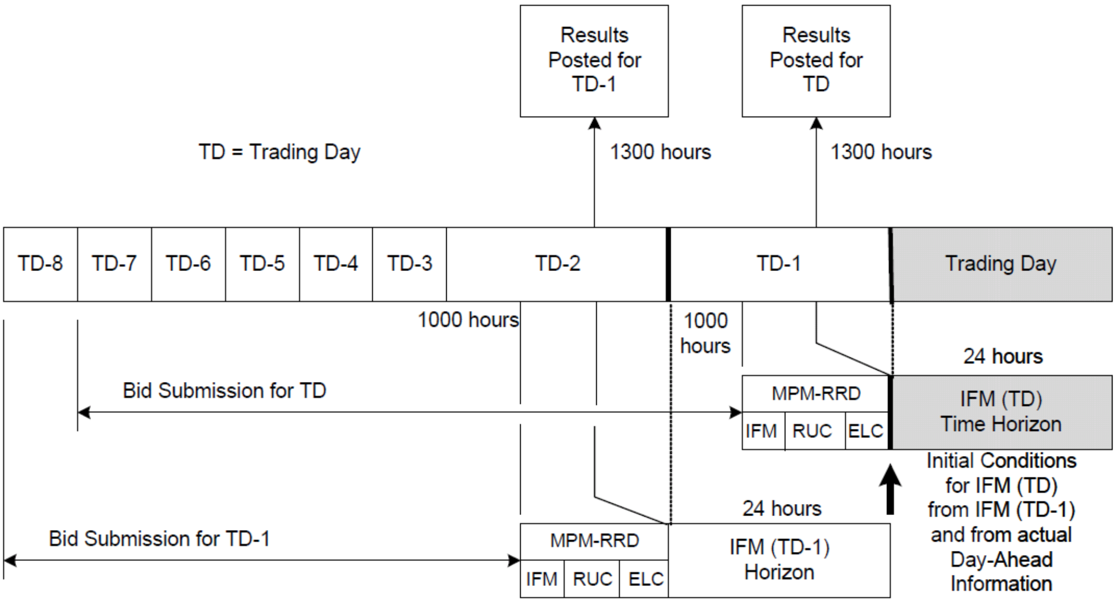

Figure 2.3 – Day-ahead CAISO market timeline [CAISO-2011a].

2.2.3. Real-Time Market

The RTM is a spot market to procure energy and AS, and manage congestion in the real-time after all the other processes of the DAM have run. This market procures energy to balance instantaneous demand, reduce supply if demand falls, offer ancillary services as needed and in extreme conditions, curtail demand. The RTM market opens at 1:00 p.m. of the day before the trading day and closes 75 minutes before the start of the trading hour. The results of the RTM are published about 45 minutes before the start of the trading hour [CAISO-2011b]. The day-ahead schedules form the basis of energy used in real-time along with day-ahead bids and newly submitted real-time bids. The market subjects bids to mitigation tests and the Hour-Ahead Scheduling Process (HASP), which produces schedules for energy and ancillary services based on submitted bids. It produces ancillary services awards, and financially binding intertie schedules [CAISO-2011a]. The HASP is the hour-ahead process during the real-time which includes a special hourly run of the Real-Time Unit Commitment (RTUC). The HASP is also one of the component processes of the RTM, and combines provisions for the CAISO to issue hourly pre-dispatch instructions to system resources that submit energy bids to the RTM and for the AS procurement on an hourly basis from system resources. Furthermore, the process includes provisions for scheduling coordinators to self-schedule changes to their day-ahead schedules and submit bids to export energy at scheduling points. The HASP also performs the MPM-RRD procedure with regards to the bids that will be used in the HASP optimization and in RTM processes for the same trading hour [CAISO-2010, CAISO-2011c].

In this context, the RTM market basically consists in three processes. These processes are the RTUC, the Short-Term Unit Commitment (STUC) and the Real-Time Dispatch (RTD) [CAISO-2011b]. The RTUC runs every fifteen minutes and uses the SCUC optimization to commit fast-start and some short-start units and to procure any necessary AS on a fifteen-minute basis. In any given trading hour, the RTUC may commit resources in the four to seven subsequent fifteen-minute intervals, depending on when the run occurs during the hour. The STUC runs once per hour near the top of the hour and uses the SCUC optimization to commit medium-start, short-start and fast-start units to meet the CAISO demand forecast. The RTD uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the trading hour to determine optimal dispatch instructions to balance supply and demand.

2.2.4. Ancillary Services Market

The AS market is performed simultaneously with the congestion management process and the DAM to obtain the regulation and operation reserves needs.

According to [CAISO-2009, CAISO-2010, CAISO-2011a, CAISO-2011b, CAISO-2011c], the four types of ancillary services that are procured in the DAM and RTM are the Regulation Down (RD), Regulation Up (RU), Spinning Reserve (SP) and Non-Spinning Reserve (NS).

- Regulation Down is described as the regulation reserve provided by a resource that can decrease its actual operating level in response to a direct electronic (AGC – Automatic Generation Control) signal from the CAISO to maintain standard frequency in accordance with established reliability criteria;
- Regulation Up is a regulation reserve provided by a resource that can increase its actual operating level in response to a direct electronic (AGC) signal from the CAISO to maintain standard frequency in accordance with established reliability criteria, i.e., the RU must be synchronized and able to receive AGC signals, and be able to deliver the AS award within 10 minutes, based on the regulating ramp rate of the resource;
- Spinning Reserve is described as the portion of the unload synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and capable of running for at least two hours, i.e., the SP must be synchronized, and be able to deliver the AS award within 10 minutes;

- Non-Spinning Reserve is described as the portion of the generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes or a load that is capable of being interrupted in ten minutes, i.e., the resource must be able to increase the generation or reduce demand as quickly as possible to its bid value (MW) reaching the indicated value in 10 minutes or less after issuance of the instruction. The resource must be capable of remaining off-line for at least 2 hours.

The ISO uses the RU and the RD to maintain system frequency by balancing generation and demand. While SP and NS resources, collectively known as operating reserves, are used to maintain system frequency stability during emergency operating conditions and major unexpected variations of the load. However, when economically feasible, the market software will procure more of a higher quality reserve, such as regulation, to meet the requirement of a lower quality reserve such as the operating reserves [CAISO-2010, CAISO-2011c]. The CAISO has a DR program, which allows loads and aggregated loads to participate in the energy and AS market. Through the process for participating load program provided by the CAISO, individual and aggregated loads of 1 MW and above can provide AS, according to the participating load technical standard [CAISO-2006, CAISO-2007a].

2.2.4.1. Ancillary Service Cascading

Under the market design, the CAISO, whenever possible, will increase its purchases of a specific type of AS that can replace for another AS. By doing so it is expected to reduce its total cost of procuring AS while meeting reliability requirements. The substitution can only occur with the purchase of bid-in AS, i.e., substitution may not involve self-provided AS [CAISO-2011b].

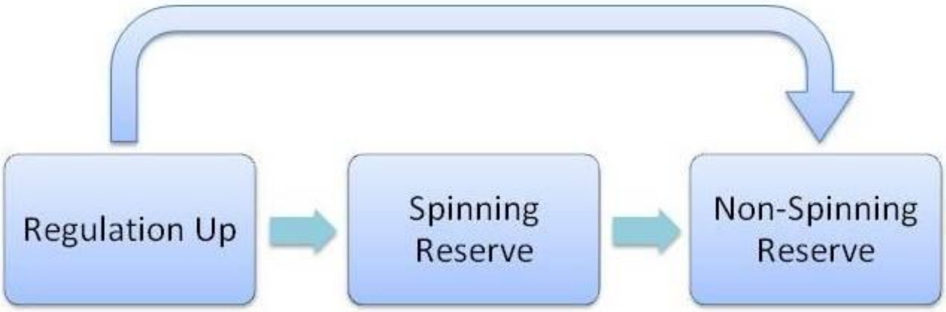

Figure 2.4 – Ancillary services cascading process.

In a more detailed view, the cascading process consists in the procurement of upward AS by replacing a higher quality AS type to meet the requirement of a lower quality AS type, if it is economically optimal to do so in the co-optimization process [CAISO-2009, CAISO-2011a]. The hierarchy of evaluating AS types in the cascaded AS procurement in the optimization process follows from the highest to lowest and never the opposite way as shown in Figure 2.4, where the RU is considered the highest upward quality reserve and the NS is considered the lowest quality reserve [CAISO-2010].

2.2.4.2. Ancillary Services Regions

In order to ensure a proper distribution of AS and reliability of the system, referring to potential congestion on internal transmission lines to external markets, the CAISO defines several AS regions that can resolve the congestion and keep a secure reliability system.

These AS regions consist in networks zones that are used to explicitly impose regional constraints in the procurement of AS. These AS regions are defined as a set of nodes. The procurement of resources on each node in the AS region is constrained by a lower and upper requirement. AS regional constraints reflect transmission limitations between AS regions that restrict the use of AS procured in one AS region to cover outages in another AS region and constraints between the regions. To ensure reliability, the AS regional constraints secure a minimum AS procurement to increase the probability of deliverability of AS. To each region it is established a maximum AS procurement target, so that the total AS procurement among RU, SP and NS reflects the current system topology and deliverability needs [CAISO-2011a].

Currently, in the CAISO there are two AS regions and eight AS sub-regions as shown in Figure 2.5. The two AS regions are the Expanded System Region that is defined as the entire CAISO balancing authority area plus all system resources at scheduling points at an outside boundary of the CAISO, and System Region that is defined as the subset of certified resources defined in the Expanded System Region that are located internal to the CAISO.

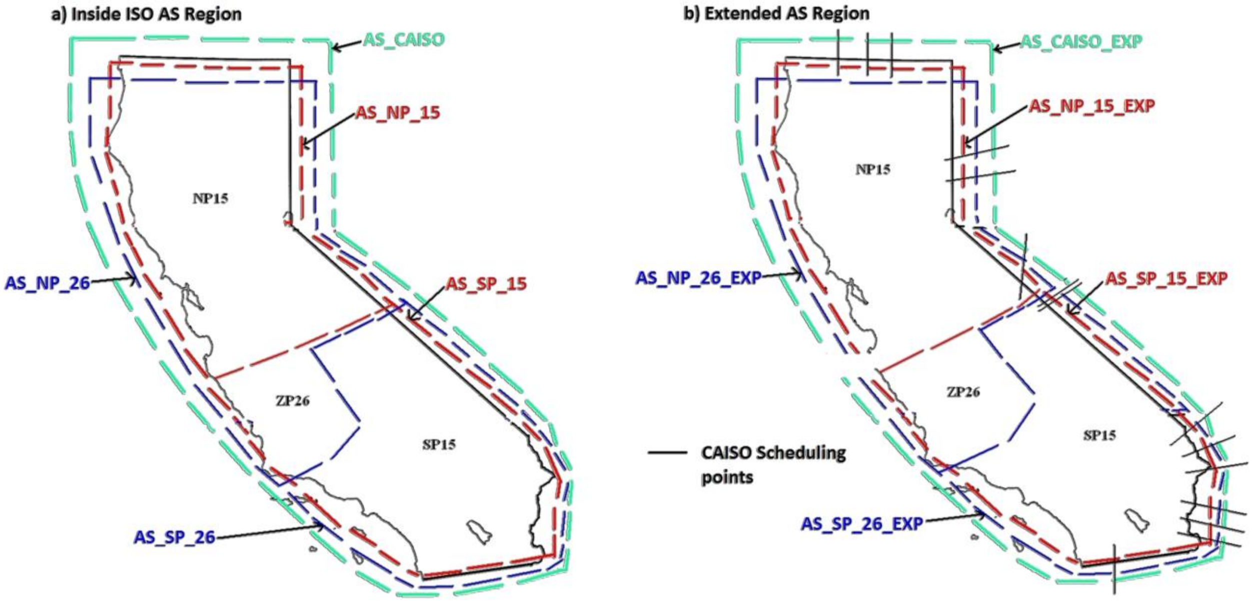

Figure 2.5 – CAISO ancillary services regions map [CAISO-2011d].

The eight identified AS sub-regions are embedded within either the system region or the expanded system region. These AS sub-regions are defined to account for expected congestion on the transmission interfaces (internal to the CAISO balancing authority area), as well as other system conditions, that may impact the ability of the CAISO to convert AS reserves into energy without exacerbating congestion on the paths that are internal to the CAISO balancing authority area. The eight AS sub-regions are the South of Path 15 sub-region, the Expanded South of Path 15 sub-region, the South of Path 26 sub-region, the Expanded South of Path 26 sub-region, the North of Path 15 sub-region, the Expanded North of Path 15 sub-region, the North of Path 26 sub-region and the Expanded North of Path 26 sub-region [CAISO-2011a, CAISO-2011d].

Figure 2.5 shows the two AS regions and the eight AS sub-regions which are divided into two parts. Part a) refers only to those AS regions which include the internal resources of each AS region. Part b) refers to AS regions besides their own internal resources which contain system resources at scheduling points at an outside boundary of the CAISO.

2.2.4.3. Ancillary Services Requirements

The requirements for AS regions are determined by CAISO in accordance with the applicable WECC and North American Electric Reliability Corporation (NERC) reliability standards and any requirements of the Nuclear Regulatory Commission (NRC) to maintain the reliability of the CAISO controlled grid [CAISO-2011b]. In this way, the CAISO may establish a minimum and maximum procurement limits for each AS region, for each ancillary service, as well for each hour, to ensure regional reliability system. According to [CAISO-2011a], CAISO can establishes minimum AS requirements for the expanded system region for each AS type, taking into account hydro-thermal supply resource proportions, path contingency, path operation transfer capability and largest single contingency.

Generally, the procurement level requirement of RU is around 350 MW, while the procurement level requirement for RD stands at 400 MW. With regards to the SP and NS reserve the procurement level is calculated as 7% of peak load of CAISO demand forecast for each reserve type in the DAM [CAISO-2011e].

2.2.5. Post-Market

The post-market consist in several activities, which the main activities summarize the data validation of energy production and demand, as well as the LMPs price correction in which the results may be incorrect. The market validation process can be seen as a two-phase process [CAISO-2011a]: the first phase correspond to the market validation, which consists in the opportunity to validate the market results before they are published to Open Access Same-Time Information System (OASIS) and CAISO Market Results Interface

(CMRI). The Day-Ahead Market allows more time to validate market outcomes before publishing results. Thus, CAISO expects that invalid Day-Ahead Market result publication in OASIS and CMRI would be unlikely. On the other hand, for the Real-Time Market, the 5-minute dispatch interval timeline provides CAISO analysis limited opportunity to identify and resolve invalid market data or solutions before the publication of the invalid market prices. In either cases, when prices are determined to be invalid after they are in OASIS, they would be corrected following the price correction process. The price correction process is precisely the second phase which is an off-line analysis which occurs after the Market results are published in OASIS and sent to Market Participants through the CMRI. The purpose of the validation is to identify and correct prices in any periods with error conditions or incorrect results. The price validation process ensures that the LMPs used for Market Settlement are based on the proper data, and that the market solution accurately reflects the power system conditions and CAISO Operator actions that should have been considered in the relevant market process. This post-publication market validation process is completed within a prescribed window of time following each market. All prices published in OASIS or in other sources are subject to potential correction during the prescribed price correction window. All prices are considered final after the prescribed price correction window has expired.

2.3. NASDAQ OMX Commodities Europe/Nord pool

The Nordic power market known as Nord Pool before 1 November 2010 it is constituted by Norway, Denmark, Sweden, Finland, Estonia and Lithuania. Each of the Nordic transmission system operators are owners of Nord Pool Spot AS. In recent years, the financial part of Nord Pool was acquired by NASDAQ OMX Commodities Europe which is a trade name of NASDAQ OMX Oslo ASA, and is authorized as a commodity derivates exchange by the Norwegian ministry of finance and supervised by the Norwegian financial supervisory authority [NASDAQOMX-2010].

NASDAQ OMX Clearing is the trade name of NASDAQ OMX Stockholm AB which is authorized and supervised as a multi-asset clearinghouse by the Swedish Financial Supervisory Authority in Sweden, as well as authorized to conduct clearing operation in Norway by the Norwegian Ministry of Finance [NASDAQOMX-2010].

The deal between NASDAQ OMX and Nord Pool ASA does not include Nord Pool Spot AS, which will continue physical electricity market trading operations independently [NASDAQOMX-2010].

The Nord Pool Spot AS essentially consists of two distinct markets – the Elspot which is a Day-Ahead Market where power is traded for delivery during the next day, and Elbas which is a continuous intraday market for trading power across the Nordic region, Germany and Estonia [NordPool-2012i]. These two markets together have about 370 players from 20 countries trading in the market, and more than 70% of Nordic power consumption is bought on Elspot [NordPool-2012a, NordPool-2012b]. However, there are two other markets present in Nord Pool. The Financial market which is used for price hedging and risk managing, and the balancing market which is a tool for the Nordic TSO's to keep balance between total generation and consumption of power real-time. Figure 2.6 shows the components of Nord Pool markets, as well as the temporal scale of operation of several markets.

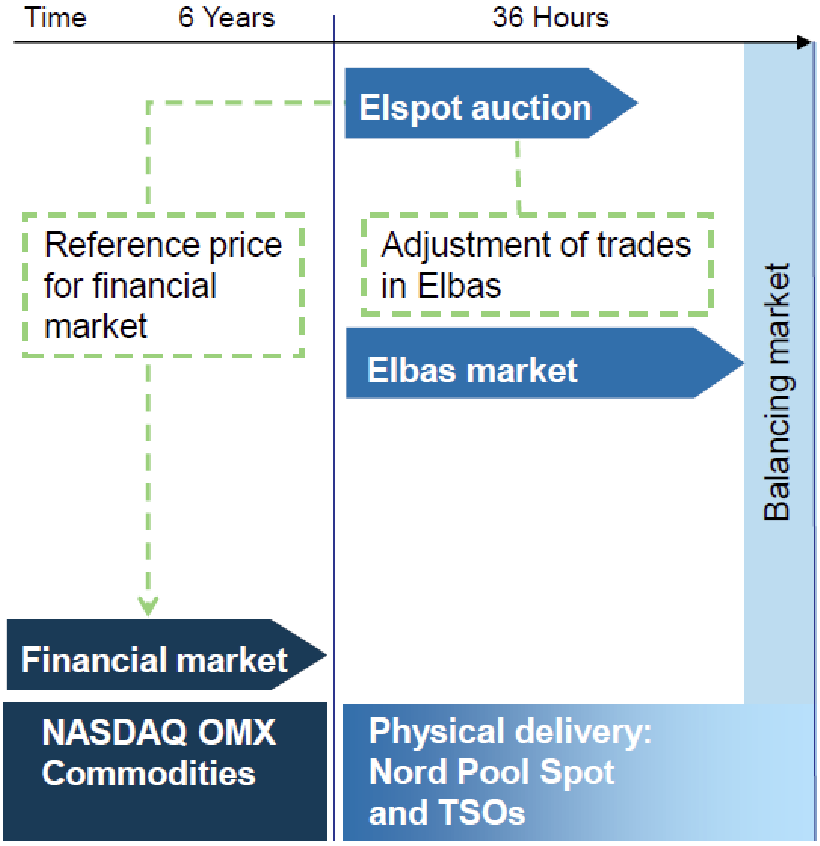

Figure 2.6 –Nord Pool market timeline overview [NordPool-2012a].

2.3.1. Financial Market

In the financial market are used financial contracts for price hedging and risk management which is managed by NASDAQ OMX Commodities. The financial contracts could be daily, weekly, monthly, quarterly and annual contracts, which may have a max time horizon up to six years. The contracts are negotiated based on the reference price provided by Nord Pool Spot. Thus, the system price and sometimes the area price determinate by Elspot can be used as reference price to the financial contracts trading. Figure 2.7 illustrates how a future financial contract works. In [NordPool-2012e] is presented a small example which illustrates the financial contract operation.

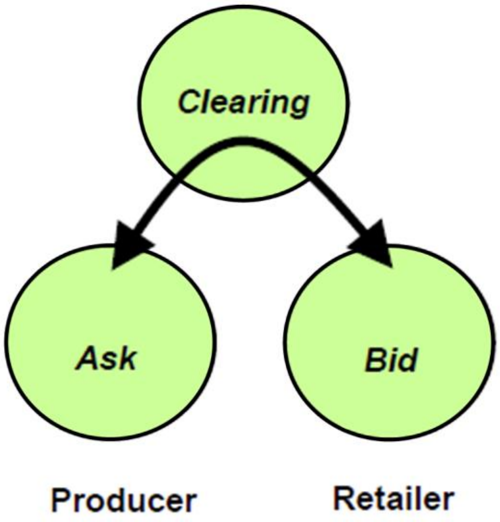

Figure 2.7 – Nord Pool financial contracts functioning [NordPool-2012e].

Assuming that a producer and a retailer sign a future contract with an hedge price of 65 EUR/MWh for the amount of energy of 4 MWh, and the average system price in the month concerned turns out to be 66 EUR/MWh, this implies that the producer pays the retailer 1 EUR/MWh * 4 MWh. In the case of the average system price in the month concerned turns out to be 63 EUR/MWh, the retailer pays the producer 2 EUR/MWh * 4 MWh. Therefore, the parties have cleared the contract. Hence, the settlement runs via clearing house, which is supervised by NASDAQ OMX Clearing.

2.3.2. Elspot – Day-Ahead Market

The Elspot consists in a DAM where power is traded for delivery during the next day. The players place their bids, hour by hour, through Nord Pool Spot's web-based trading system (SESAM), which calculation method is based on an application of the social welfare criteria in combination with market rules. Figure 2.8 show the daily routines timeline of the DAM where players can put their bids up to twelve days ahead, while the Gate Closure for the bids with the delivery next day at 12 p.m. When all players have submitted their bids, the equilibrium between the aggregated supply and demand curves is established for all bidding areas. The system and area prices are calculated and published normally between 12:30 p.m. and 12:45 p.m. [NordPool-2012a, NordPool-2012c].

The Elspot calculates the system price based on the sale and purchase bids disregarding the available transmission capacity between the bidding areas in the Nordic market. The system price is the Nordic reference price for trading and clearing of most financial contracts. The market is divided into several bidding areas. Whereas, the available transmission capacity may vary and congest the flow of electrical energy between the bidding areas, and thereby different area prices are established [NordPool-2012c].

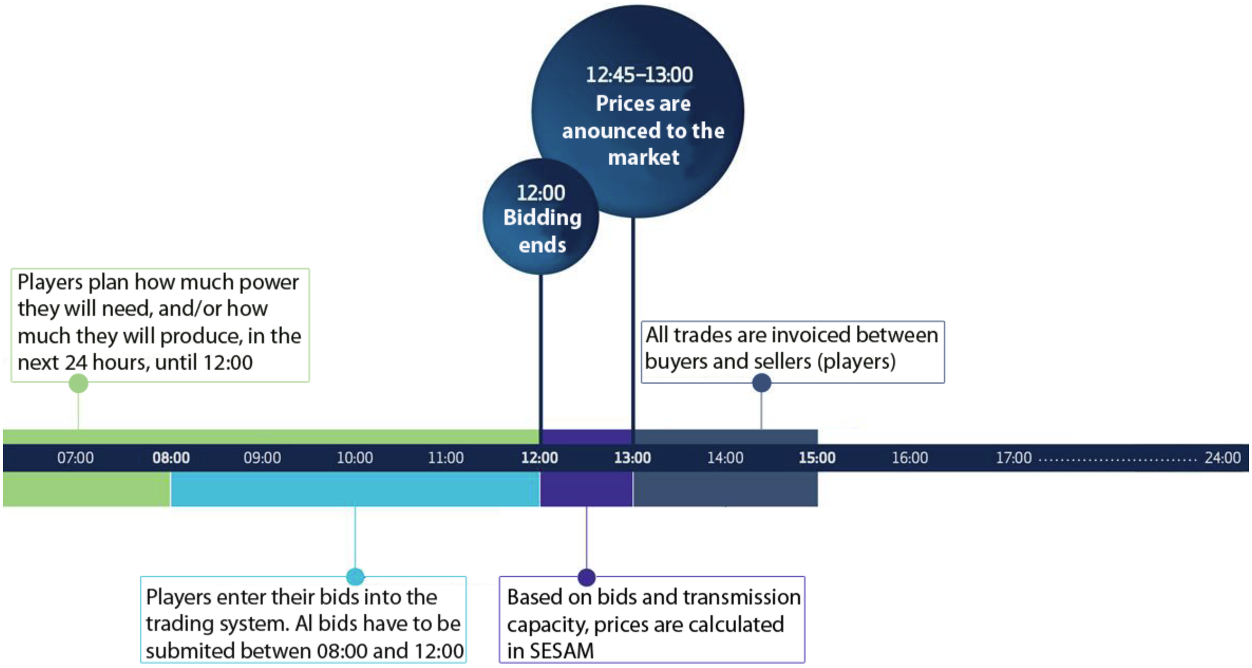

Figure 2.8 – Elspot timeline [NordPool-2012a].

The players have the ability to make their bids through three individual bidding mechanisms completely distinct, or may choose to make their bids by combining these three mechanisms. In this way, the three bidding mechanisms are described below [NordPool-2012h]:

- Single hourly bid – The player specifies the purchase and/or sales volume for each hour and may choose between a price dependent and a price independent bid. Once the price for each hour is determined, a comparison with a player's bid for that day establishes the delivery for the player;
- Block bid – The block bid consists in a specified volume and price for at least three consecutive hours. This type of bid mechanism has a particular condition in which the block bid must be accepted in its entirety, covering the all hours and the volume specified;
- Flexible hourly bid – is a single hour sales bid where the players specify a fixed price and volume without specified the hour. This implies that the bid can be dispatched at any time of the day, according to the preference of the system operator optimization.

2.3.2.1. Bidding Areas

The Nordic power market has adopted a zonal approach to manage the grid congestion, thus yielding the market split into several areas. The different bidding areas created by the TSOs help indicating constraints in the transmission systems, and ensuring that regional market conditions are reflected in the price.

Due to congestion in the transmission system, the bidding areas may get different prices called area prices. When there are constraints in transmission capacity between two bidding areas, the power will always go from the low price area to the high price area. Nord Pool Spot calculates a price for each bidding area for each hour of the following day.

Each participating country in the Nord Pool, through its local TSO, establishes the number of bidding areas in which the country is splited. In Nord Pool the number of Norwegian bidding areas can vary. Currently, there are five bidding areas. Sweden is divided into four bidding areas. Denmark is divided into two areas (Eastern and Western Denmark). Finland, Estonia and Lithuania constitute one bidding area each one [NordPool-2012d, NordPool-2012e]. Figure 2.9 presents the map of the Nord Pool, highlighting the constituent countries and their different bidding areas.

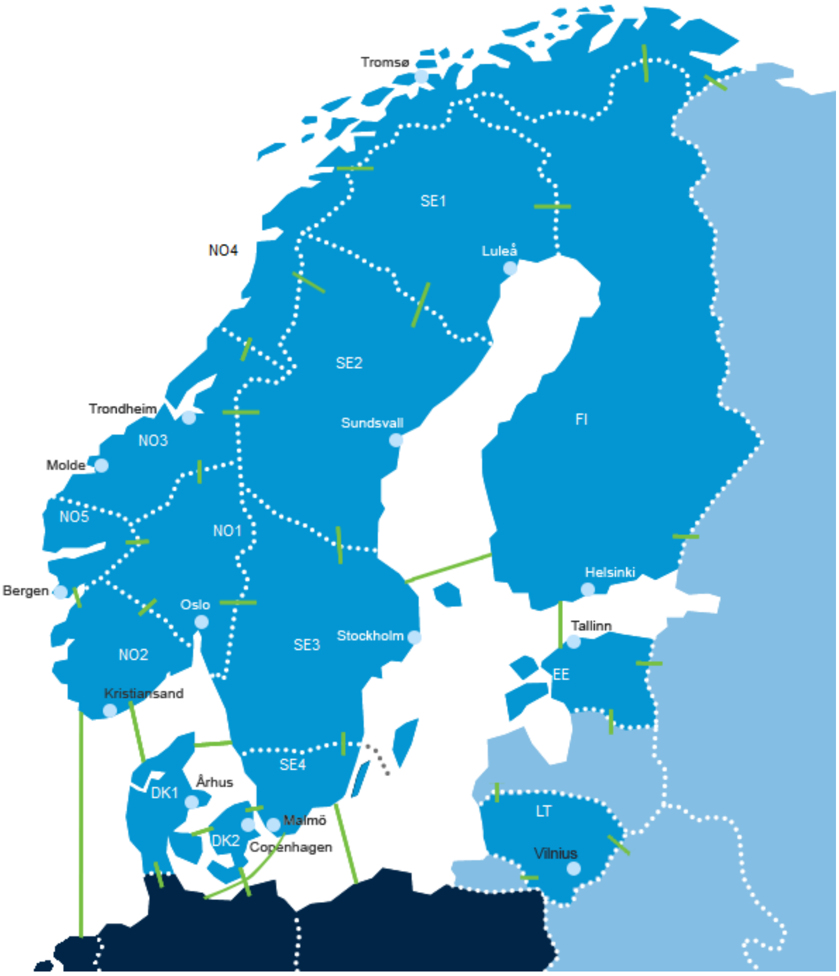

Figure 2.9 – Nord pool market areas map [NordPool-2012g].

In order to correctly originate the bidding areas, one can know that the negotiation process runs approximately in accordance with the following steps [Bjorndal-2001]:

- The market is cleared based on the supply and demand schedule bids given by the market participants without any grid constraints limitations. This produces market clear price energy (i.e., the average daily price that disregards congestion in the day-ahead market, that is the reference system price for the financial market);

- In case of the resulting power flows induce transmission capacity problems, the nodes are partitioned into areas;
- Assuming that the market is divided into two defined areas, the area with greater supply capacity than the demand is defined as the low-price area, whereas the area with more demand than the supply is determined as high-price area;
- Grid transmission over the zone-boundary is fixed when curtailed to meet the violated capacity limit;
- The zonal markets are now cleared separately giving one price for each area – one area with the low-price and other with the high-price. If the power flow resulting from this equilibrium still violates the capacity limit and/or if any new limits are violated the process will be repeated again, possibly generating additional areas;
- The revenue of the transmission operator (from capacity charges) is equal to the price difference times the transmission across the zone-boundary.

2.3.2.2. System Price

The system price is the average daily price that disregards the congestion in the DAM. For each hour, the system price is determined by the intersection of the aggregate supply and demand curves which are representing all bids and offers of the market. In Figure 1 illustrates the symmetrical curve from the market used to set the system price [NordPool-2012e, NordPool-2012f].

Figure 2.10 – System price determination through purchase and sale curves intersection [NordPool-2012f].

In this way, the system price is an equilibrium market price without consideration of the transmission lines capacity constraints between bidding areas.

2.3.2.3. Area Price

The Area price is the price determined for each bidding area, which is considered the lines congestion capacity constraints between the bidding areas. However this price is only calculated when the power flow between bidding areas exceed the trading capacity. In this case, when the need for transmission exceeds the available transmission capacity, the prices are lowered in surplus areas and raised in deficit areas, which results in different area prices. The main goal of the assignment of area prices is the ability to relieve grid congestion between the bidding areas.

In what concerns the high price in the deficit area, the players will sell more and purchase less while in the surplus area it is the opposite. In the area price calculation the transmission capacity between the deficit and the surplus area is used to the maximum. In this way, the power flow will go from the surplus areas (lower price) to the deficit area (higher price). Thereby, in the deficit area the sale will give a parallel shift of the supply curve while in the surplus area the additional purchase will give a parallel shift of the demand curve [NordPool-2012e, NordPool-2012f].

Following the same principle of system price determination through the intersection of the supply and demand curve, Figure 2.11 shows the curve of the area pricing determination for cases of high (deficit) and low (surplus) price.

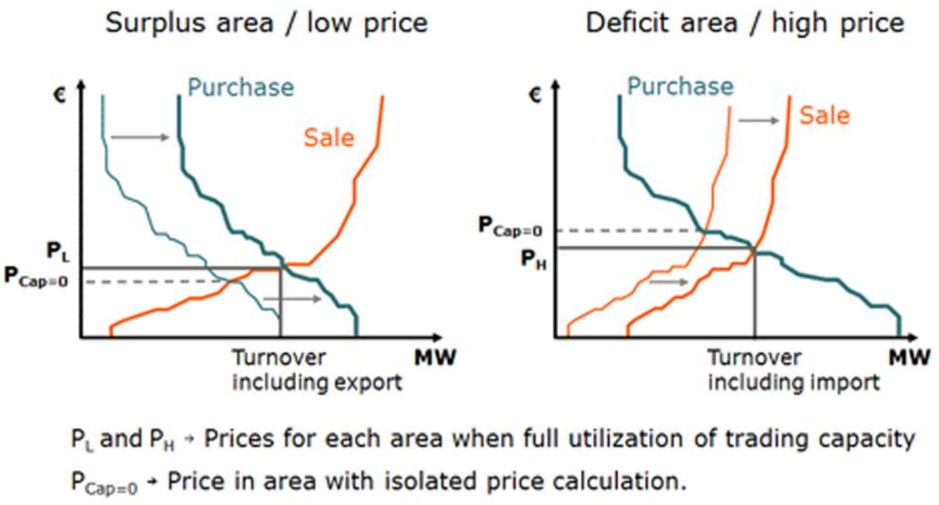

Figure 2.11 – Surplus and deficit area price curves determination [NordPool-2012f].

As can be seen in the Figure 2.11, through this process one can find a relatively balance between the area price in the surplus area and in the deficit area. Thereby, the price is relatively lower in the surplus area and relatively higher in the deficit area.

In the event that power flow in interties in consecutive periods not exceeding the maximum limit of transmission capacity of interties, the market price of the areas are the same, so there are no differentiation between areas prices.

2.3.3. Elbas – Intraday Market

Elbas is an intraday market for trading power across the Nordic region, Germany, Estonia and Lithuania. Elbas supplements Elspot and helps secure the necessary balance between supply and demand in the power market, offering opportunities for risk reduction as well as increased profit.

As it is known, when it approaches the delivery time of energy in real-time, the necessary energy forecast is improved to accentuate that the energy forecast traded in DAM is not adequate for the obtained forecast in real-time. This is due to significant deviations from production and/or consumption. In this context, incidents may take place between the closing of Elspot and delivery of the next day. For example, a nuclear power plant may stop operating, or winds may cause higher power generation than planned at wind turbine plants. Therefore, players through the Elbas can trade volumes close to real-time to bring the market back in balance.

After closing of the Elspot auction (at 2 p.m.), capacities available for Elbas trading during the 24 hours of the following day are published. In Elbas, the trading takes place every day until one hour before delivery. The prices are set based on a first-come, first-served principle where lowest sell price and highest buy price come first, regardless of when a bid is placed [NordPool-2012a, NordPool-2012i and NordPool-2012j].

2.3.4. Balancing Market

The Balancing power market is a tool for the Nordic TSO's to keep balance between total generation and consumption of power in real time. The TSO have the responsibility to ensure the demand provision and maintain the transmission grid frequency stable, according to the limits for the frequency control.

The balancing market culminates in the power adjustments within hours of delivery of energy, i.e., in this market each TSO negotiates individually with each player in order to maintain the system balance. In this way, the TSO acquire Ancillary Services, like regulation reserve and other services, necessary for the complement of system balance [NordPool-2012k].

The mechanism of balancing of the Nordic electricity market consists in three steps. The planning, regulation and settlement balance, which are defined in agreements between the market players (Balance Responsible Parties, BRPs) and the TSOs [Nordel-2008], described as follows:

- The balance planning consists in the obligation of the market players to balance their portfolios of production and purchase against consumption and sales on hourly basis;

- The balance regulation consists in the regulating power by the TSOs to continuously maintain the overall balance of the power system. The TSOs use physical adjustments to generation or consumption to cover the grid imbalances of the players. This regulation is conducted using several kinds of ancillary services, some of which are shown in Figure 2.12;
- The balance settlement consists in TSO calculation of the BRP's imbalance (balance power for production and consumption) and the resulting economic settlement. The production and consumption balance power is calculated for each hour. The calculations are based on measured data, which TSOs are obliged to report.

Figure 2.12 shows the explained mechanisms, and the resources which contribute to power system balance.

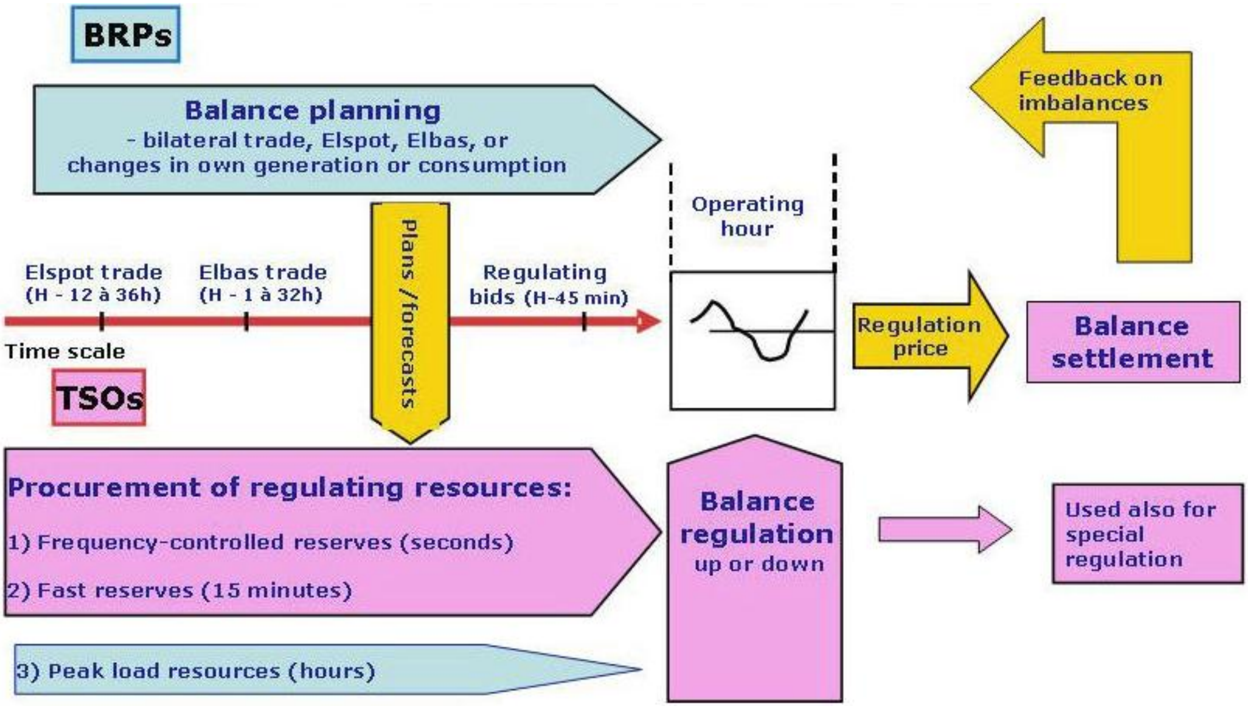

Figure 2.12 – Mechanisms for balancing the power system [Nordel-2008].

In this context, the main AS traded are [Kristiansen-2007 and Nordel-2008]:

- Frequency controlled reserves – consists in reserves which are activated by frequency deviations. Usually, this service is divided into two different categories. The frequency controlled normal operation reserve, which implies that TSO shall keep the frequency between 49.9 and 50.1 Hz. The limit puts a requirement on availability of 600 MW for these reserves with a frequency response of 6000 MW/Hz; and the frequency controlled disturbance reserve, which is used for larger frequency deviations down to 49.5 Hz. In this service the reserve available is 1000 MW and the frequency response is 2500 MW/Hz;

- Fast reserves is a AS which are activated manually, and must be able to restore the automatic reserve within 15 min;
- Peak load resources are resources which can be used by the TSO for balance regulation. Usually, such peak load resources can take several hours to activate in situations when the fast reserve should prove insufficient. A peak load arrangement should be an exceptional and temporary solution to overcome a critical period. Therefore, the implementation of this service is supervised by each TSO, because each country has a set of rules adapted to the needs of their respective power system.

2.4. MIBEL

The Iberian Electricity Market (MIBEL – Mercado Ibérico de la Electricidad) is a regional electricity market composed by the countries of Portugal and Spain. This market is based on setting of a market for daily delivery of energy to the next day, with a format similar to the majority in Europe. This way, the MIBEL consists of three distinct markets, The Financial market (known as Forward Market) which is used for price hedging and risk management, the Day-Ahead Market where power is traded for delivery during the next day, and the intraday market which work as a market adjustment of MIBEL.

The OMIP (Operador de Mercado Ibérico de Energia, Portuguese pole) is responsible for managing the trading operations in the futures market whose underlying asset is electricity. The financial market is regulated by OMIclear (Sociedade de Compensação de Mercados de Energia) which is the Iberian energy clearing house that manages the settlement system.

The OMIE (Operador del Mercado Ibérico de Energia, Spanish pole) is the managing entity of the DAM and intraday market, which establishes programs for the sale and purchase of electricity for the next day. Thus, the OMIE is responsible for conducting assessments of the DAM and intraday market.

The overall management of the electrical system of each zone is the responsibility of the respective TSO, which in addition to its usual features, individually manages its own market for ancillary services. Sometimes the DAM and intraday market is divided into two zones, each zone corresponding to the respective country. This is due to the limited capacity of interconnection between the two zones causes interconnection congestion [MIBEL-2009].

The Ancillary Services market is operated by the TSO of each country. They have to ensure the contract and settlement of AS, to ensure the balance between production and consumption, through efficient and competitive mechanisms. The AS to be contracted in the market are complementary services (explained in subsection 2.4.4). These services are subject to remuneration and should be contracted based on market mechanisms in a competitive environment. The adopted model establishes a implicit separation between the complementary ancillary services to which the system uses on a regular basis (secondary regulation and regulatory regulation) who are contracted on the basis of asymmetric market and those which are needed occasionally (synchronous compensation, black start and interruptible service) based on bilateral contracts [MIBEL-2009].

Figure 2.13 shows the arrangements for procurement existing in MIBEL.

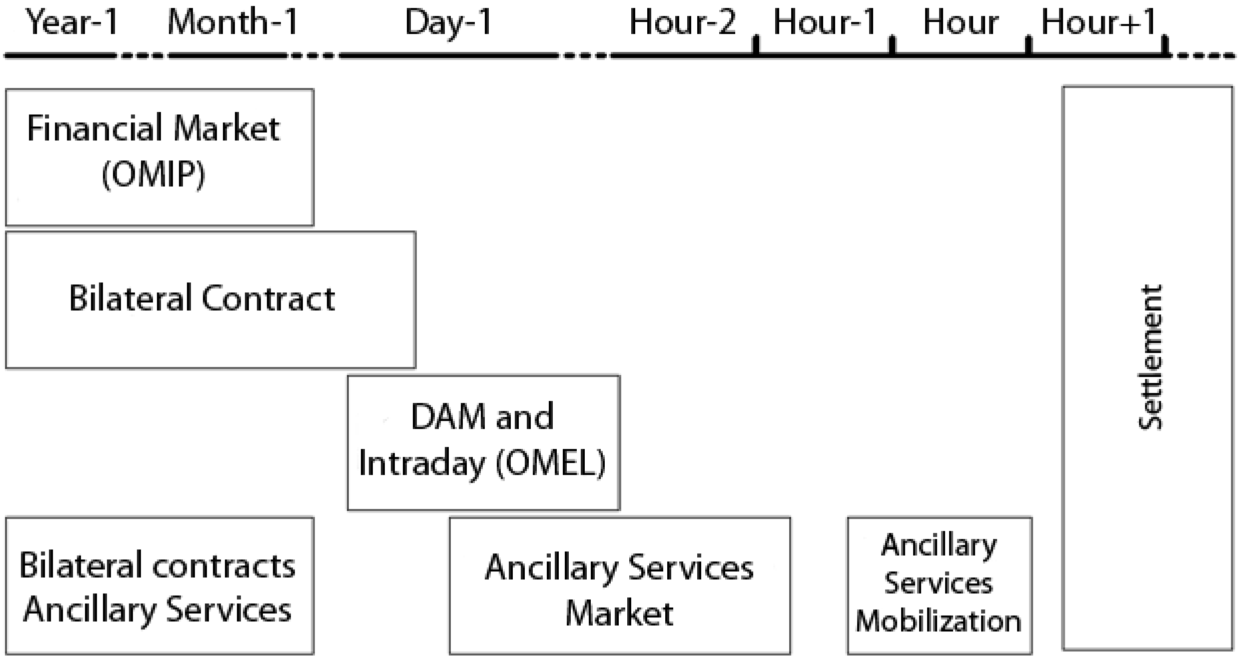

Figure 2.13 – MIBEL market timeline overview, adapted from [Pereira-2009].

2.4.1. Financial Markets

The financial market of MIBEL is an organized market designed for price hedging and risk management, which is managed by OMIP. In this market, there are three types of contracts available for trading. The futures contracts which admit physical or financial settlement, the Forwards contracts which have physical nature and the swaps contracts which are of financial nature. The futures contracts use the DAM market price as a reference price, with only financial settlement [MIBEL-2009].

2.4.2. Day-Ahead Market

The Iberian DAM is managed by OMIE and consists of electricity transactions for the next day, based on the presentation of purchase and sale offers of electric power carried out by the market players. In this market each player can submit between 1 to 25 bids for each hour. The bids which players present to the Market Operator (MO) can be simple or complex. However, only the sellers can post simple and complex bids, while the buyers can only submit simple bids. Simple bids are economical offers for sale energy, in which for each hour the player establish the amount of energy and its price. The complex bids are based on simple bids with the introduction of some technical and/or economical conditions, as described below [OMIE-2012a]:

- The indivisibility condition enables to set a minimum operation value, which is indicated in the first bid of each hour;
- Voltage gradient condition allows establish the maximum difference between the start hour and end hour power of the unit production, which limits the maximum energy to confer on the basis of the meeting the previous and the following time, to avoid sudden changes in unit's production that can not technically follow the same;
- The minimum entries condition consists in the minimal entries in service of a unit production per day. The unit production refuse to participate in the outcome of the meeting of the day, if not obtained for all of their production on an entry exceeding a fixed amount established in euro cents;
- The scheduled stop condition allows performing a scheduled stop time a maximum of three hours, in the case of the unit production has been removed by the agreement does not meet the condition required for minimal entries in service. Thus, avoiding stop from it program in the last hour of the day before to zero in the first hour of the next day, by accepting the first bid for the first three hours of it offer as simples bids, with the sole condition that the energy is provided descending the first bid of each hour.

2.4.2.1. Market Development Sequence

The market has a developmental sequence in which the closing hour of the DAM will be at 10 a.m. the day before the delivery date. The market is based on the process of meeting supply and demand curves from the bids for sale and purchase. The outcome of the meeting of the curves will be published at 11 a.m.

After the process of meeting the supply and demand curve, between 11 and 14 hours, with the incorporation of bilateral contracts, one can obtain the daily base operation dispatch for each system. In this way, the SO analyze and solve possible technical congestion constraints arising from the process of meeting the DAM of the interconnections between the two systems and the declaration of bilateral contracts, thus deliver their programs viable daily duties. After the process of solving technical constraints in the DAM, the market relating to secondary regulation starts. In this market, players offer their regulation bids with the respective price, for every hour of the next day. Each bid must meet a pre-established relationship between the up and down reserve. The final viable daily dispatch of the DAM is published before the 16 hours and includes the result of the Ancillary Services (AS) market regarding to the secondary regulation [MIBEL-2009].

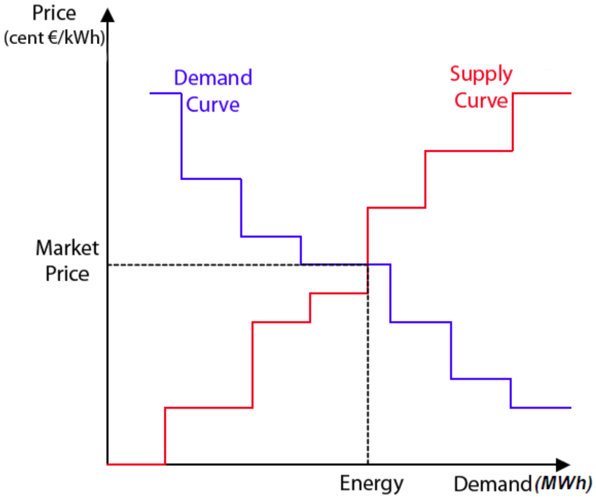

Figure 2.14 – Symmetric market clearing price determination [Pereira-2009].

2.4.2.2. Market Splitting

The Iberian market is treated as a single market when there are no violated congestion constraints at the interconnections between the two systems corresponding to each country. In certain situations where such constraints are violated, the market is separated into two distinct price areas, thereby causing the market splitting. In this regard, based on the process of determining the price exposed in subsection 2.4.2.1, the market splitting process may result in two different processes for determining the market price [MIBEL-2009]:

- In the situation where the meeting of the supply and demand curves, resulting in interconnections power flow which not exceeds the interconnection capacity, the market price is unique to the Iberian system, since the dispatch has technical and economic viability;
- In the case of the meeting of supply and demand curves, resulting in interconnections power flow which exceeds the interconnection capacity, the initial market solution is unfeasible, so the two market areas are dealt with separate supply and demand curves appropriated to each area. However, the demand curve for the export system is placed as a quantity corresponding to the interconnection capacity, while the supply curve for the importing system consists of an equivalent amount. The meeting of the curves for each of the systems results in different market prices for each market.

This principle of market splitting areas is identical to the market split mechanism of Nordpool. This way, subsection 2.3.2.3 describes the mechanism of the separate market areas.

2.4.3. Intraday Market

The intraday Iberian market is a adjustments market which provides a match between supply and demand more accurate and close to real time than the allowed by the DAM, solving thus possible mismatches in successive stages of programming. In intraday market, and in order to rectify their previous positions, players can also buy and sell energy.

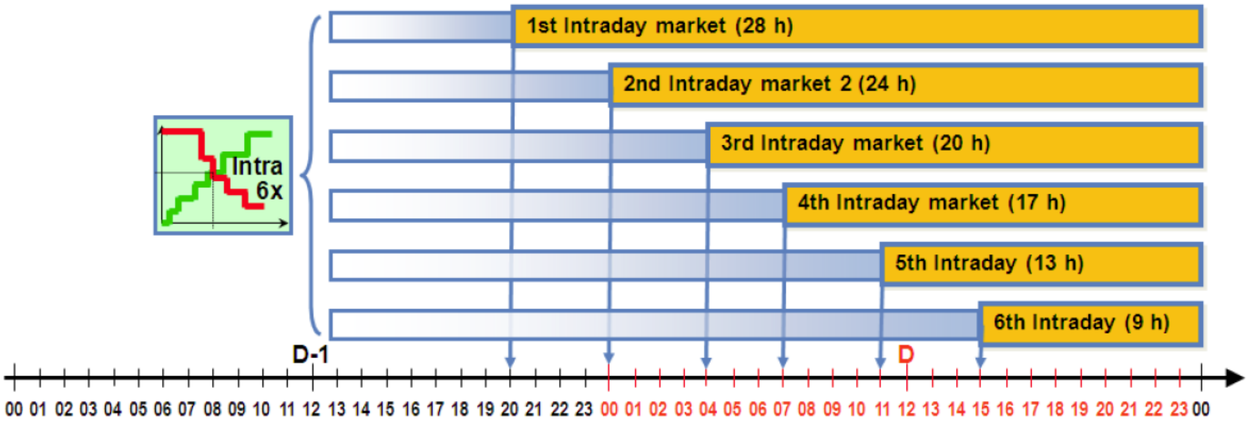

Figure 2.15 – Intraday market structure sessions [MIBEL-2009].

Table 2.1 shows the distribution of schedules per session and their intrinsic activities of the intraday market [OMIE-2012b].

Table 2.1 – Intraday market session schedules [OMIE-2012b].

	1º Session	2º Session	3º Session	4º Session	5º Session	6º Session
Opening session	16:00	21:00	01:00	04:00	08:00	12:00
Closing session	17:45	21:45	01:45	04:45	08:45	12:45
Coordination	18:30	22:30	02:30	05:30	09:30	13:30
Reception coordination breakdowns program	19:00	23:00	02:45	05:45	09:45	13:45
Constraints analysis	19:10	23:10	03:10	06:10	10:10	14:10
End time dispatch publication	19:20	23:20	03:20	06:20	10:20	14:20
Planning horizon (time periods)	28 hours (21-24)	24 hours (1-24)	20 hours (5-24)	17 hours (8-24)	13 hours (12-24)	9 hours (16-24)

This market is divided into six sessions, taking place at each crossing of a marginal nature between supply and demand curves. The first session includes 28 hours (the last 4 in day D-1 and the 24 in day D). The sixth covering the last nine hours of the day D. Figure

2.15 shows schematically the structure of the intraday market covering all session's constituents of the market [MIBEL-2009 and OMIE-2012b].

2.4.4. Ancillary Services Market

In MIBEL, the Ancillary Services market is separated into two markets, individually managed by the TSO of each respective country.

The AS are divided into two categories [MPGS-2008 and MIBEL-2009]:

- Mandatory services, which are not paid and which are encompassed the voltage regulation, frequency regulation and maintenance of stability;
- Complementary services, such as static synchronous compensation and the reserve, secondary regulation, the interruptible rapid and black start, which are remunerated through the AS market or through bilateral contracts.

Currently, only secondary regulation and regulatory reserve are remunerated in the form of competitive market. The other AS can be contracted bilaterally.

Additionally, there is the process of solving the technical constraints that mainly involves the simulation of the network AC power flow based on economical dispatches obtained in several electricity markets. In this way, the process of solving the technical constraints consists of three levels, relative to the DAM, intraday market and real-time energy delivery managed by the respective TSO.

In the DAM market, the process of solving technical constraints is separated into two distinct phases. The first phase consists in modifying the procurement program by security criteria and the second phase consists in the rebalancing of the generation/consumer system. To this end, the supply units (large groups of thermal and hydro plants) and consumption for pumping present energy and price bids for mobilization and demobilization of energy. The players associated with the consumption bids of pumping units are paid by using the maximum value between the energy bids value given in the process of solving technical constraints and the bids made on the DAM.

In the event of energy mobilization, the players associated with the generation units are remunerated by using the minimum value between the energy bids value given in the process of solving technical constraints and the value of bids submitted and not matched at the DAM. In case of energy demobilization, selling players are required to pay the energy price matched at the DAM.

In several sessions of intraday market where arise technical constraints, these are solved through the elimination of bids that arise, without implying any additional cost to the system. The costs resulting for the increase in the market clearing price of intraday market, due to the elimination of bids is supported by consumers.

Finally, the third level of the process of solving the technical constraints consists in the technical constraints detected in real-time which are solved by mobilizing the bids of regulation reserve. Every hour, any additional costs of resolution of technical constraints in real-time are remunerated around the consumption made at this time, in proportion to its consumption in DAM [MPGS-2008, MIBEL-2009 and ERSE-2012].

In order to obtain a better understanding of the AS in the Iberian market, is shown below the detailed definition of the main AS associated with frequency regulation managed by the SO of each area [MPGS-2008 and MIBEL-2009]:

- The primary regulation is associated with generators statism, which is a mandatory AS, unpaid for all generators in service. The power variation resulting from its action should be effected within 15 seconds before disturbance causing the deviation of frequency below 100 mHz and linearly between 15 and 30 seconds to deviations in frequency between 100 and 200 mHz;
- The secondary regulation (usually known as Spinning Reserve) is a AS remunerated by market mechanisms, and its valuation is composed of two parts: the reserve price, valued in accordance with the maximum of the marginal prices of secondary regulation reserve to “down” and “up” in hourly; and energy of secondary regulation, valued at the price of the last energy bid of regulation reserve mobilizes in each hour. The onset of action of the secondary regulation should take no longer than 30 seconds and its action should be completed and may be supplemented by action the regulation reserve (tertiary regulation), no longer than 15 minutes;
- The tertiary regulation consist in the variation of the maximum power generation program that can be carried out in a unit production and/or balance area in a maximum time of 15 minutes and can be maintained at least for 2 hours in a row. This reserve is an additional service, paid by market mechanisms and composed of two parts: minimum reserve of tertiary regulation and additional reserve. The minimum tertiary regulation is established by the SO for each period, taking as reference the maximum losses of production caused directly by the failure of a single element of the electrical power system, increased by 2% of expected consumption. The additional regulation reserve aims to guarantee the coverage of the consumption and operating system where the consumption scheduled by the SO exceeds by more than 2%, consumption resulting from the production markets and when the forecast generation loss due to successive failures and/or delays in the connection or increase of thermal groups is greater than the tertiary regulation established. The market players present their

regulation reserve bids to up and/or down, between 18 and 21 hours, for each period of the next day.

2.5. Conclusion

All over the world, electricity restructuring placed several challenges to governments and to the companies that are involved in generation, transmission and distribution of electrical energy.

The markets discussed in this section are the result of consequent paradigm shift. In this regard, special attention was given to the several models and designs of energy and ancillary services markets.

In this section is presented an overview of ancillary services in different markets, in which the Table 2.2 represents a summary of the AS adopted by the real market models studied in this chapter.

Table 2.2 – Ancillary services summary.

Ancillary Services	BETTA	CAISO	Nord Pool	MIBEL
Frequency Regulation	Frequency Response Regulating Reserves	Regulation Down Regulation Up	Frequency Controlled Reserve	Primary Regulation
	Fast Reserve Standing Reserve	Spinning Reserve	Fast Reserves	Secondary Regulation
	Warming Reserve Hot standby Reserve	Non-Spinning Reserve Replacement Reserve	Peak load resources	Tertiary Regulation
Voltage Control	Obligatory Reactive Power Enhanced Reactive Power	AGC Regulation	Obligatory Reactive Power Enhanced Reactive Power	AGC Regulation Synchronous Compensation
Back-Up services	Black Start	Black Start	Black Start	Black Start

In Table 2.2 it is possible to identify the differentiation of ancillary services in the markets studied. However, to describe each service in detail one can realize that in general the frequency control services are divided into three parts.

When comparing the services identified in the CAISO market with relating to MIBEL, one can verify that the Regulation Down and Regulation Up refers to the Primary regulation of MIBEL, while Spinning Reserve refers to Secondary Reserve and the services Non-Spinning Reserve and Replacement Reserve refers to Tertiary Reserve. Although it is understood that the markets designs are different, the main services are similar, with some changes at the level of response time, duration period, as well as the service settlement mechanisms.

Besides the AS for the frequency control deeply covered in this chapter, the Table 2.2 emphasizes other ancillary services, such as services related to voltage control and Black Start capacity.

Voltage control consists in maintaining voltage through injecting or absorbing reactive power by means of synchronous or static compensation.

In BETTA the voltage control is divided into two services – the Obligatory Reactive Power service which is the provision of varying reactive power output (at any given output the generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection); and the Enhanced Reactive Power service which is the provision of voltage support that exceeds the minimum technical requirement of Obligatory Reactive Power service (including synchronous compensation) or reactive power capability from any other plant or apparatus which can generate or absorb Reactive Power (including Static Compensation equipment) that is not required to provide the Obligatory Reactive Power service [NGET-2012a].

The Black Start service is the capability of a generating unit to start up without an external power supply, called on as a means of restoring supplies following a major failure on all or part of the network [EURELECTRIC-2004]. This service is common to all markets, and in the vast majority it is traded through bilateral contracts between generation's units and system operators.

Chapter 3

Ancillary Services Market models

3. AS Market models

This chapter provides an overview of the proposed and implemented simulation models. Most features of the presented simulation models focuses on characteristics of real market models. Some of the models consider innovative methodologies for solving the optimization problem, namely the introduction of Bialek topological factors in the scope of determination of the impact of Ancillary Services (AS) dispatch in network congestion. Most of the models are related to the Independent System Operation (ISO) operation. However, it is also proposed a complete model that addresses the market simulation from the perspective of a Virtual Power Player (VPP) management. In this way, some particular characteristics of the VPP management are considered, including the aggregation of several kinds of energy generation technologies, as well as the introduction of complex contracts between the VPP and players.

In this chapter five distinct simulating models are available in the scope of the AS market, energy and ancillary services joint market, applied to different levels of an ISO and a VPP Operation.

3.1. Introduction

The design and development of simulation models and tools for AS simulation are essential to allow a proper management of the most varied existing energetic resources. In that case, the AS procurement by the ISO/VPP must take into account in its simulation model the characteristics inherent in each technology, as well as ensure market competitiveness in order to get the best possible management of all resources in a market environment.

In order to simulate complex models of markets, market players (ISO, VPP and other players) use tools with the capability of simulating electricity market processes. In this way, the simulator must be able to deal with the complex reality of the electricity market and its dynamics evolution. In this context, multi-agent simulators are appropriate for this kind of problems, because it allows a good flexibility in the electricity markets simulation, since agents can have different behaviors and interests of each other [Praça-2003]. Currently, there are several tools which allow simulating the electricity markets operation, each one with its own characteristic, for example: the Simulator for Electric Power Industry Agents (SEPIA) is based on a plug and play architecture which allows users to easily create simulations involving several machines in a network, or in a single machine, using various processing units [Harp-2000]; the Electricity Market Complex Adaptive System (EMCAS) is a simulator which uses an agent based approach with agents' strategies based on learning and adaptation for electricity markets [Koritarov-2004]; Power Web is a Web-based market simulator which allows several participants to interact from very distinct zones of the globe. It is a rather flexible system that allows the definition of simulations with a large set of scenarios and rules [Zimmerman-2004]; the Agent-based Modelling of Electricity Systems (AMES) is an open-source computational laboratory for the experimental study of wholesale power markets restructured in accordance with U.S. Federal Energy Regulatory Commission (FERC)'s market design [Li-2009]. An electricity market simulator called MASCEM is being developed in GECAD, and all the developed models in this chapter will be implemented in MASCEM. MASCEM is a multi-agent based electricity market simulator which is a modeling and simulation tool that has been developed with the purpose of studying complex restructured electricity markets operation. It provides market players with simulation and decision-support resources, being able to give them competitive advantage in the market [Praça-2003].

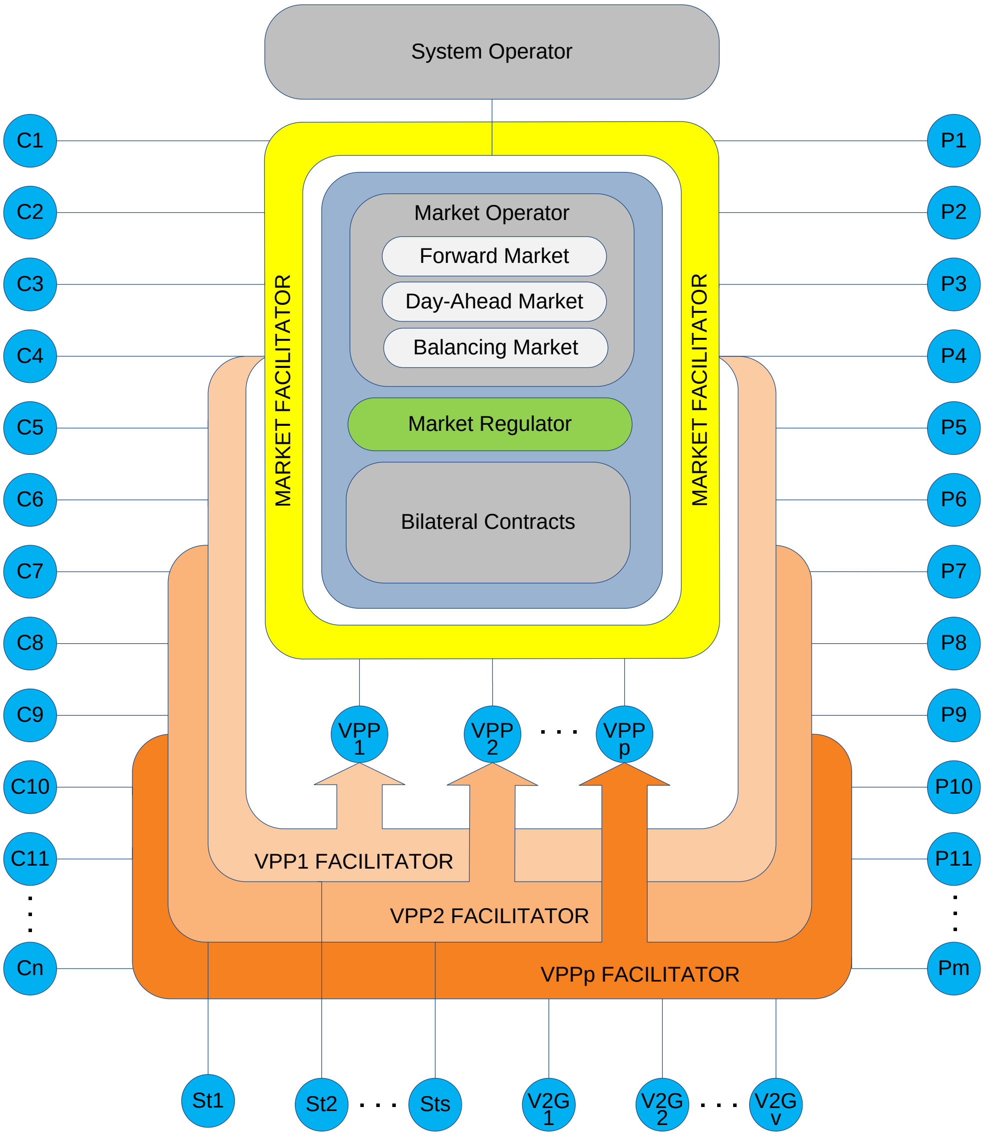

Figure 3.1 – MASCEM architecture in [Pinto-2012].

Market players are complex and unique entities, having their very own characteristics and objectives, making their decisions and interacting with other players. So, MASCEM was developed as a multi-agent based simulation tool, modeling the complex dynamic market players, including their interactions and medium/long-term gathering of data and experience. MASCEM uses game theory, machine learning techniques, scenario analysis and optimization techniques to model market agents and to provide them with decision-support [Vale-2011]. MASCEM includes several negotiation mechanisms usually found in electricity markets. It can simulate several types of markets, namely: pool markets, bilateral contracts, balancing markets, forward markets. This implies that each agent must decide whether to, and how to, participate in each market type. Figure 3.1 presents MASCEM global architecture, proposed in [Pinto-2012], with the representation of its most important entities and interactions.

As presented in Figure 3.1, there are several entities involved in negotiations in the scope of electricity markets; this multi-agent model represents all the involved entities and their relationships. MASCEM multi-agent model includes: a Market Facilitator Agent, Seller Agents, Buyer Agents, VPP Agents, VPP Facilitator Agents, a Market Operator Agent and a System Operator Agent [Praça-2003, Vale-2011]. In order to develop a more realistic simulator it is proposed in this thesis a variety of models for energy and AS negotiation to be implemented in MASCEM.

A key objective of the proposed models in this thesis is to provide a better simulator intrinsic ability to simulate energy and AS markets, based on real and current models functioning of several markets placed on MASCEM. During the models description, some important contributions of this work are present, namely the energy and AS joint market simulation, in which is considered the power flow for each utility; the introduction of Bialek topological factors in solving the network congestion by considering the AS dispatch in the network flow; and the ancillary services dispatch in the scope of a distribution network operation with a high penetration of Distributed Energy Resources (DER). To this end, one can use a novel method for solving the problem. In this way, a brief description of the characteristics inherent in each proposed simulation model is presented. Table 3.1 summarizes the market models studied in this chapter. The first column of Table 3.1 presents the highlights that characterize each model.

The Ancillary Services Market model consists in the simultaneous optimization of ancillary services (Regulation Down (RD), Regulation Up (RU), Spinning Reserve (SP), Non-Spinning Reserve (NS)). Depending on the real market model, these AS may be classified differently, but in general they have very similar characteristics. Therefore, these AS are designated by the MIBEL as primary, secondary and tertiary regulation reserves. In the scope of the simulation, the model includes the possibility of substitution between services designated by AS cascading. Thus, this model illustrates the basic operation of the AS market, being used as the reference model for the remaining models presented in this section.

Table 3.1 – Market models characterization.

Characteristics	Model				
	Ancillary Service Market	Energy and AS joint market	Joint market considering AS bidding regions	Joint market considering Bialek coefficients	Joint Market applied by VPP
Market model	AS market	Joint Market	Joint Market	Joint Market	Joint market
AS cascading process	Yes	Yes	Yes	No	No
Network operation	No	No	AC OPF	AC OPF with Bialek topological factors	AC OPF with Bialek topological factors
Resource management goal	Minimization of ISO operation costs	Minimization of ISO operation costs	Minimization of ISO operation costs	Minimization of ISO operation costs	Minimization of VPP operation costs
AS bidding regions	No	No	AS bids and procurement by regions of the network	AS bids and procurement by regions of the network	AS bids and procurement by regions of the network
Relaxation variables	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by the energy resources of other regions, including external suppliers
Complex Contracts	No	No	No	No	Developed five types of complex contracts between players and VPP

The Energy and AS Joint Market model is based on a principle of energy and AS joint market where seller's agents can make offers simultaneously for the energy and AS markets with a global maximum power generation limit. This model fits to the basic principle of the joint market, i.e., the co-optimization of energy and ancillary services similar to the implemented in several US electricity markets, such as the CAISO, Electric Reliability Council of Texas (ERCOT) and New York Independent System Operator (NYISO), in order to obtain the most efficient cost solutions.

The Joint Market model considering AS bidding regions is based on the methodology of CAISO functioning, which considers the co-optimization of energy and AS, where ancillary services are procured by network regions. The ISO establishes the AS regions and its respective requirements. The model is able to simulate a regional AS dispatch. Regions are areas of the network, which implies that each region will be assigned a set of network nodes. In this model the interties between network regions, follow the same principle of constraints applied to interties between countries.

The Joint Market model considering Bialek coefficients introduces a new methodology for energy and AS joint market simulation with consideration of the impact of the dispatch of all services in the network power flow. This model has the ability to previously analyze congestion that each AS implies in the network, rejecting solutions that may cause network congestion. To this end, the model uses the topological factors methodology proposed by Janusz Bialek in [Bialek-1997]. With this method it becomes possible to know the amount of power that each generator is supplying to loads, as well as the congestion in lines caused by each generation unit.

The Joint Market model applied by VPP considers the methodology referred to the previous model applied in the scope of distribution network operation with high penetration of DER essentially composed of Distributed Generation (DG), Demand Response (DR) and storage units, which can be managed by a VPP, as well as the introduction of complex contracts between VPP and the players in the resources scheduling process.

Related to the VPP management and the players' goals, a major contribution of this work lies in the introduction of complex contracts which establish conditions that guarantee competitive benefits for both parties. The terms of these contracts, include the advantage of setting clear objectives for generation, remuneration, working time, among others, to enable the VPP aggregating the most interesting players to their objectives, as well as the players getting best benefits in the aggregation to an particular VPP when compared to act alone in the same market or aggregate to other VPPs.

The design, development and application of these methodologies in the simulation model of the energy and AS joint market, leads to a more cohesive, feasible and applicable to the simulation of real markets, making these models the main contribution of this work to the development of MASCEM. The main goal of MASCEM's is to be able to simulate as many market models and types of players as possible so it can reproduce in a realistic way the operation of real electricity markets.

In this way, the implementation of these models in MASCEM makes this a more robust and, at the same time, a more flexible simulator regarding the simulation of electricity markets.

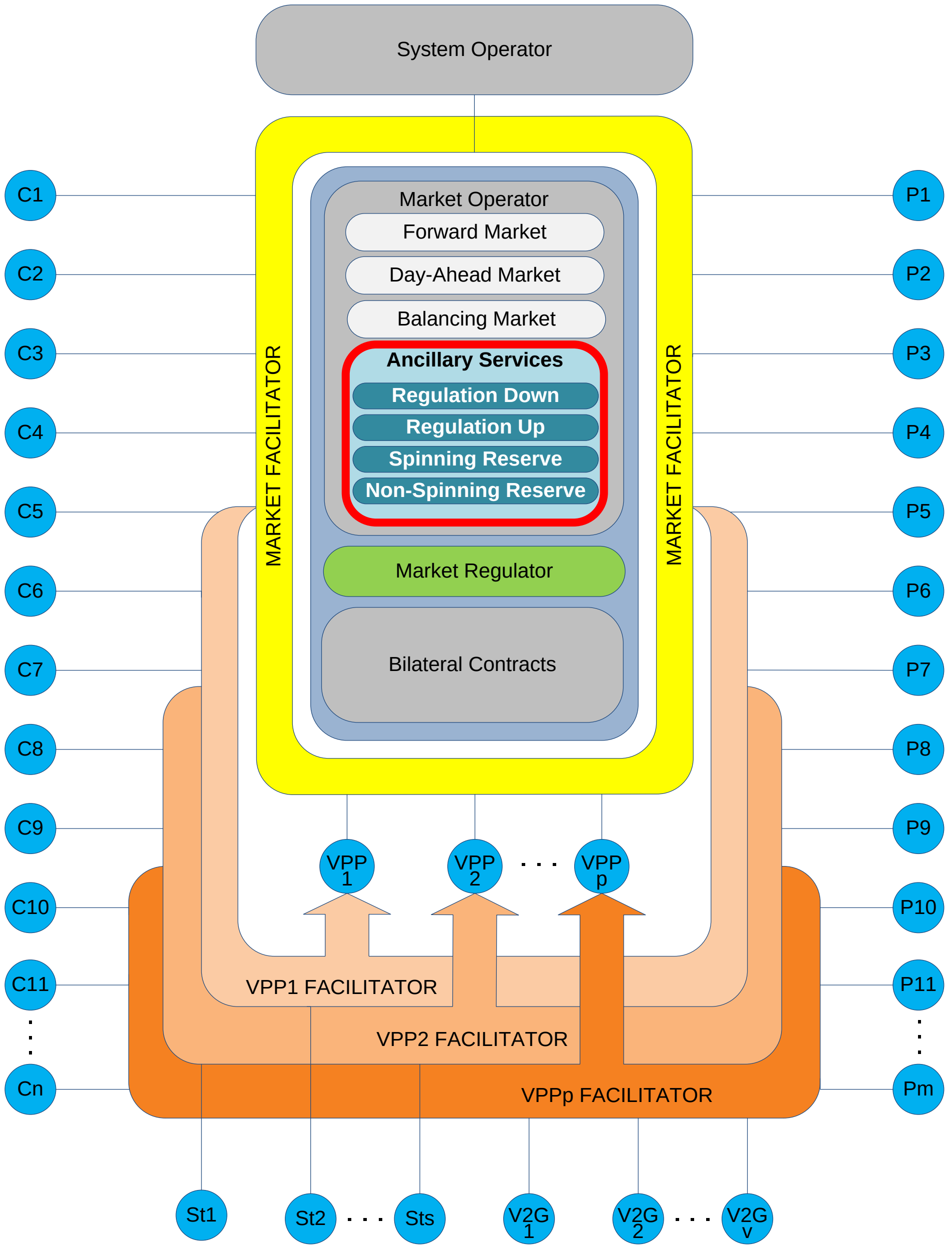

Figure 3.2 – Updated MASCEM architecture.

The implementation of the proposed models in the new MASCEM structure will be similar to the architecture shown in Figure 3.2, in which the part relating to AS refers to the contribution of the work developed in this dissertation for the simulator continuous improvement. This enables the MASCEM to be used as a simulation and decision-support tool for short/medium term purposes.

Computational tools used in models implementation

A detailed description of several tools used in the development of simulation models of electricity markets are presented below. These tools are used as the basis of operation of the MASCEM market simulator.

MASCEM is developed in OAA[1] [OAA-2012] framework and in Java Virtual Machine 1.6.0 [JAVA-2012]. The OAA's ICL[2] is the interface and communication language shared by all agents, which allows MASCEM to integrate a variety of software modules [Pinto-2011b].

The optimization models to be included in MASCEM to simulate the AS markets are developed in General Algebraic Modeling System (GAMS) which is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a stable of integrated high-performance solvers. GAMS is tailored for complex, large scale modeling applications, and allows the user to build large maintainable models that can be adapted quickly to new situations [GAMS-2008]. GAMS is specifically designed for modeling linear, nonlinear and mixed integer optimization problems. The system is especially useful with large, complex problems. A large number of solvers for mathematical programming models allow users to solve a huge variety of problems [GAMS-2007]. The optimization problems related with the proposed models are solved using DICOPT[3], CPLEX[4], CONOPT[5] and LINDOGlobal[6] solvers.

The JAVA agents of MASCEM and the optimization process in GAMS were linked with the MATrix LABoratory (MATLAB) which is a powerful software of numeric computation, developed in 1978 by Cleve Moler and Jack Little, cofounders of MathWorks[7]. The main characteristic of MATLAB is the use of matrixes as the basic data structure [Graham-2005]. MATLAB is a high-level technical computing language with an interactive environment, ideal for algorithm development, data visualization, data analysis, and numeric computation. MATLAB can be used in a wide range of applications, including signal and image processing, communications, control design, test and measurement, financial modeling and analysis, and computational biology. Thus, MATLAB is used in several applications in the industry, as well as in academic activities, and it has been applied to several problems of science and engineering. MATLAB has toolboxes that allow obtaining the solution for several types of problems such as the ones related to numerical analysis, data analysis, matrix calculus, and signal processing. The user can use the available toolboxes or program functions and routines to solve the envisaged problem [MATLAB-2010]. In the scope of this thesis, MATLAB is used as a tool for preparation of input data, as well as the organization and illustration of the results of the optimization. Although via MATLAB it is possible to perform the optimizations of the presented models, GAMS was chosen as optimization tool, because

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[1] Open Agent Architecture

[2] Interagent Communication Language

[3] DIscrete and Continuous OPTimizer

[4] Simplex algorithm and C programming

[5] CONtinuous global OPTimizer

[6] Linear, Integer, Nonlinear, Dynamic Optimization Global

[7] The MathWorks, Inc., Natick, United States, 2010, www.mathworks.com

of its advantages in solving optimization problems using deterministic methods compared with MATLAB.

3.2. Ancillary Services Market model

This section presents a simulation model of a generic AS market, which considers the optimization of the most common ancillary services in the liberalized market environment (RD, RU, SP and NS). This model is based on a principle of AS market design – The Rational Buyer, which is an simultaneous AS auction with downward substitution for the different commodities (RU, SP, NS) in order to minimize the cost of the AS procurement [Papalexopoulos-2001].

3.2.1. Problem Description

This model is designed to perform the dispatch of the AS market, based on an asymmetric pool, considering the four most common AS in the liberalized market environment. Regulation Down, Regulation Up, Spinning Reserve and lastly the Non-Spinning Reserve are the AS simulated in this model. In order to be able to understand the presented model, Figure 3.3 presents a flowchart representative of the structure simulation model of the operation method of the AS market.

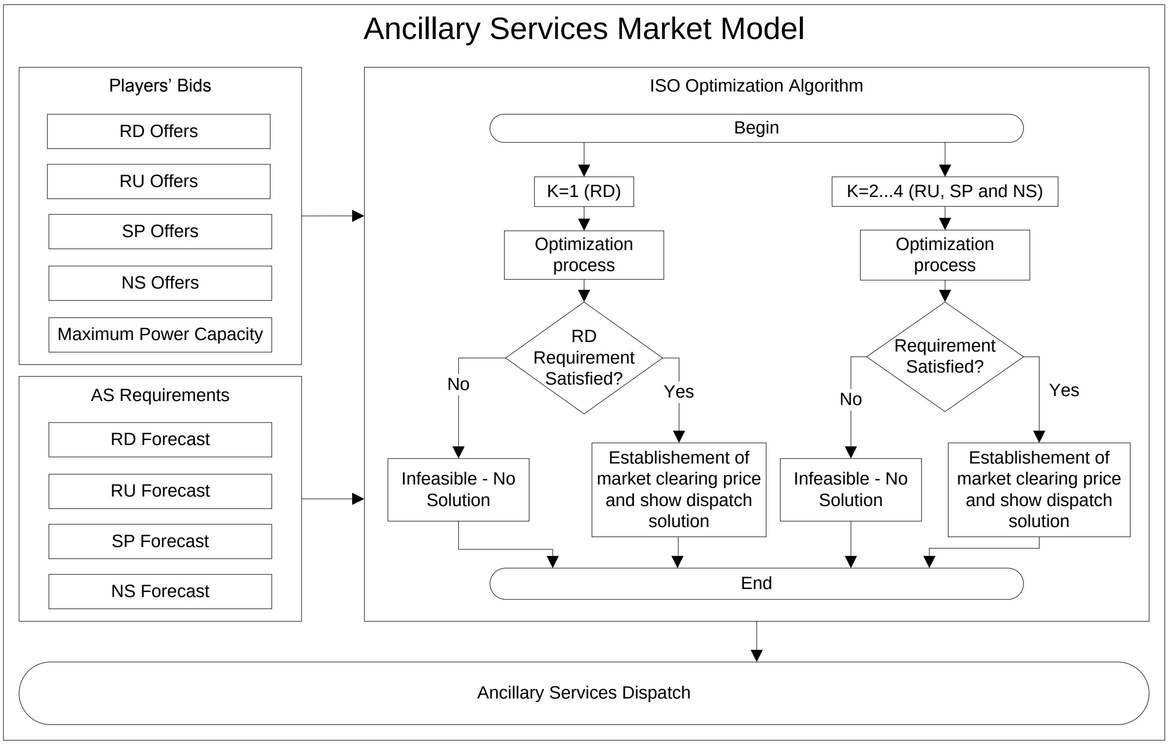

Figure 3.3 – AS market diagram.

The players acting on the market can present their bids for any of the four AS previously mentioned, with different capacities and prices for each service.

The proposed flowchart presented in Figure 3.3 illustrates the essential processes of the optimization algorithm of the model. The algorithm is initialized by reading the input data relating to bids of each AS and the quantities required by ISO for each ancillary service.

The algorithm is divided into two distinct parts. One of the parts refers to the Regulation Down, while the other part of the algorithm is relate to the simultaneously simulation of ancillary services (Regulation Up, Spinning and Non-Spinning Reserve).

The optimization process is performed by the optimization tool GAMS, which contains several solvers capable of solving the optimization process in multiple ways.

To the RD service, the next step is to select all offers until the service requirement is met. In the case where the amount required energy by ISO for the service is not satisfied, the algorithm informs the ISO that the solution is infeasible for this service.

In case the AS requirement have been satisfied, takes place the establishment of the market clearing price based on the last offer obtained in the dispatch of this service, ending this part of the algorithm.

With regards to the second part of the algorithm, the next step in the optimization process considers two possibilities depending on the results of the optimization process. If is no possible solution, the algorithm informs the ISO that the solution is infeasible. In this way, the ISO will have to procure, through other trading methods, resources which may provide the remaining amount of power necessary to satisfy the requirement. In case of obtaining feasible solutions, the algorithm performs the final process in which presents the results of market clearing price of all services, as well as the respective dispatches.

The presented algorithm has a drawback which is the difficulty of determining all possible combinations of all services based on the last bid price corresponding to the market clearing price. That is, during the optimization, the model should consider the market clearing price which may give a different dispatch and more economic advantage to what is determined. Regarding the implemented algorithm, the market clearing price is executed and the cost that the ISO has to pay is calculated to each player based on the last bid price dispatched.

3.2.2. Mathematical Formulation

The proposed problem aims to minimize the market clearing price of the AS market. This problem can be perfectly modeled as an optimization problem. The characteristics of this problem are complex, yet they leading to the need of using a solver capable of solving Mixed Integer Non-Linear Programming (MINLP) model. In this regard, the resolution of the problem can result in solutions based on local minima optimums and, in global optimal solutions, which is the best possible solution.

The objective function in (3.1) is formulated with the aim of minimizing the total cost which the ISO has to pay for the AS provided by the players who present their bids in the AS market. In case of all participants in each ancillary service market can not satisfy the requirement of each service, the relaxation variables are activated in order to meet the difference between the required and supported by market players. The ISO procure resources capable of satisfying the variable through bilateral contracts. These variables allow the AS dispatch to be feasible in cases where market participants fail to meet the AS requirements.

Related to these variables, there is a penalty that increases the system operation costs. However, this penalty is not supported by the ISO, but by all players participating in the respective service which needed the use of this variable.

$$\begin{gathered}Minimize\ f = \min\\ \sum_{t=1}^{T}\sum_{k=1}^{N_K}\sum_{r=1}^{N_R}\left[P_{AS(r,k,t)} \times C_{AS(r,k,t)}^{\max} + RLXD_{(k,t)} \times W_{RLXD(k,t)} + RLXU_{(k,t)} \times W_{RLXU(k,t)}\right]\\ k \in \{1,2,3,4\}\end{gathered} \tag{3.1}$$

The power required by each ancillary service which must meet between minimum and maximum requirements imposed by the ISO for each service *k* in each period *t*, is represented by equation (3.2). Equation (3.3) represents the constraint concerning the minimum and maximum amount of generation offered by each resource *r* for service *k* in period *t*.

$$\begin{gathered}R_{AS(k,t)}^{\min} \le R_{AS(k,t)} \le R_{AS(k,t)}^{\max}\\ \forall t \in \{1,...,T\}; \forall k \in \{1,...,N_K\}\end{gathered} \tag{3.2}$$

$$\begin{gathered}P_{AS(r,k,t)}^{\min} \le P_{AS(r,k,t)} \le P_{AS(r,k,t)}^{\max}\\ \forall t \in \{1,...,T\}; \forall k \in \{1,...,N_K\}; \forall r \in \{1,...,N_R\}\end{gathered} \tag{3.3}$$

The Regulation Down constraint is represented by equation (3.4), which establishes the dispatch of the resources for this service, in period *t*.

$$\begin{gathered}R_{AS(k,t)} = \sum_{r=1}^{N_R} P_{AS(r,k,t)} \times X_{AS(r,k,t)}\\ \forall t \in \{1,...,T\}; k = 1\end{gathered} \tag{3.4}$$

The Regulation Up constraint is represented by equations (3.5) and (3.6). These constraints have special nonnegative relaxation variables, which have the principle of penalties for infringement the equality of the equation. These variables are useful to help the equation to converge in some special cases. In this way, these variables are used for cases of failure of generators which do not participate in the market, to ensure the continuity of RU service in period *t*, and in cases where the service requirement is less than the minimal amount of power of the bid, resulting in an excess of generation.

In this mathematical formulation, the ancillary service cascading is considered. RU can be used as SP and/or NS after the RU requirement is met. This AS substitution process is possible due to the AS hierarchical nature, which allows the replacement of a high quality reserve for a lower quality reserve, but not the reverse. The substitution of RU self-provisions for SP or NS is not allowed.

$$R_{AS(k,t)} = \sum_{r=1}^{N_R} P_{AS(r,k,t)} \times X_{AS(r,k,t)} + RLXD_{(k,t)} - RLXU_{(k,t)} \quad \forall t \in \{1,...,T\}; k=2 \tag{3.5}$$

$$R_{AS(k,t)} - SLCK_{(t)}^{RU\_SP} - SLCK_{(t)}^{RU\_NS} \geq R_{AS(k,t)}^{\min} \quad \forall t \in \{1,...,T\}; k=2 \tag{3.6}$$

Equations (3.7) and (3.8) represent the Spinning Reserve constraints which follow the same principle of the RU constraints. However, SP can only be used in cascade with Non-Spinning reserve for each period *t*, thus following the ancillary service hierarchical nature.

$$R_{AS(k,t)} = \sum_{r=1}^{N_R} P_{AS(r,k,t)} \times X_{AS(r,k,t)} + RLXD_{(k,t)} - RLXU_{(k,t)} + SLCK_{(t)}^{RU\_SP} \quad \forall t \in \{1,...,T\}; k=3 \tag{3.7}$$

$$R_{AS(k,t)} - SLCK_{(t)}^{SP\_NS} \geq R_{AS(k,t)}^{\min} \quad \forall t \in \{1,...,T\}; k=3 \tag{3.8}$$

The Non-Spinning constraint illustrated in equation (3.9), allows RU and SP to participate in NS service for each period *t*.

$$R_{AS(k,t)} = \sum_{r=1}^{N_R} P_{AS(r,k,t)} \times X_{AS(r,k,t)} + RLXD_{(k,t)} - RLXU_{(k,t)} + SLCK_{(t)}^{RU\_NS} + SLCK_{(t)}^{SP\_NS} \quad \forall t \in \{1,...,T\}; k=4 \tag{3.9}$$

Equation (3.10) represents the maximum upward capacity limit of resources for the AS which need the increase of the power generation, in each resource *r* for period *t*.

$$\sum_{k=2}^{N_K} P_{AS(k,r,t)} \leq P_{CAP(r,t)} \quad \forall t \in \{1,...,T\}; \forall k \in \{2,3,4\}; \forall r \in \{1,...,N_R\} \tag{3.10}$$

Through the constraints previously explained, the model is able to determine the best possible solution for the AS market. This simulation model can be used for an ISO, TSO or a VPP.

3.3. Energy and AS Joint Market model

This section presents a joint market simulation model which was published in [Soares-2011]. This proposed model is based on a principle of energy and AS market where agents can make offers for a simultaneous energy and AS markets with a global maximum energy limit. This joint market model allows the ISO to globally optimize all offers and to transfer energy between the energy and the AS market.

3.3.1. Problem Description

The model is characterized by designing the joint clearing process of the energy and AS market. In this way, the market optimization considers the data relating to the supply and demand energy curves, as well as the AS bids. The main goal of this model is to combine the energy and AS markets in order to obtain the most economically advantageous solution. Figure 3.4 shows the diagram of the simulation model.

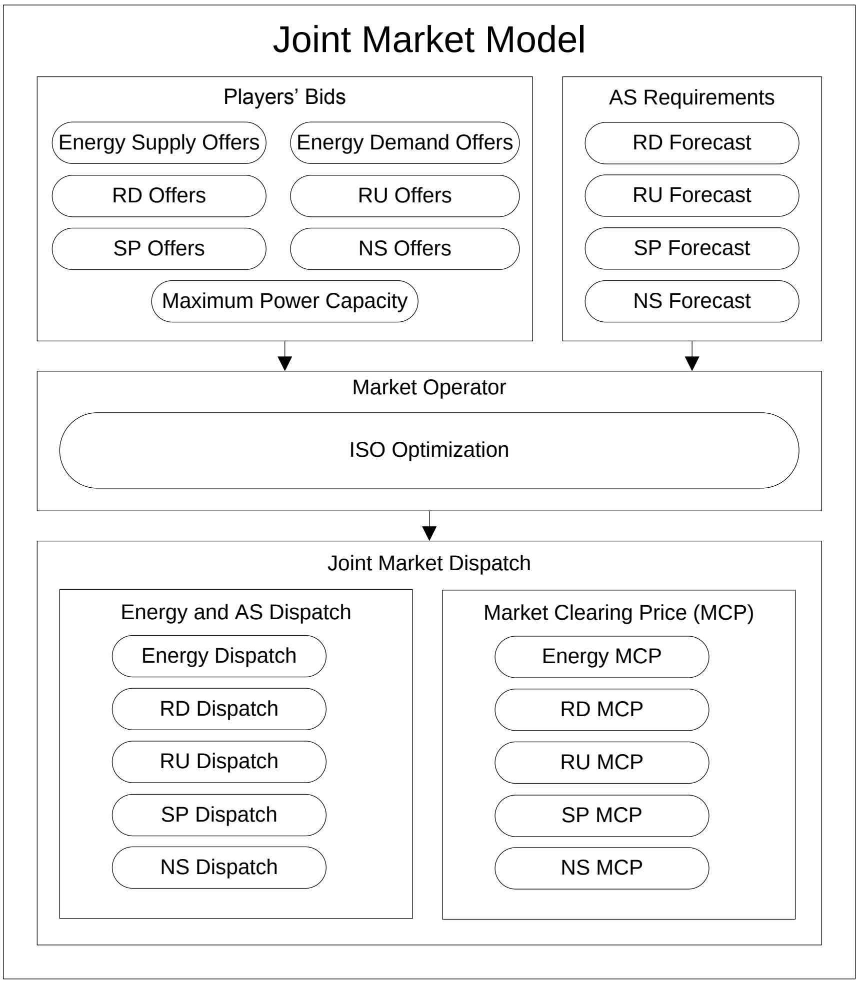

Figure 3.4 – Energy and AS joint market diagram.

The model results from the establishment of the order the market price of each joint market commodity.

The optimization process of this model is similar to optimization model presented in section 3.2.1. The differences consist in the inclusion of energy service in the optimization process, in which the algorithm for energy service is based on symmetric market model. This model considers the curve relating to the supply by the generation resources, as well as the curve relating to the demand. In this algorithm the intersection curves determine the energy market clearing price. The energy market simulation is simultaneously performed with the AS market, related to RU, SP and NS services.

3.3.2. Mathematical Formulation

The objective function in (3.11) is formulated with the objective of finding the total minimal cost taking into account the AS and energy markets bids and rules. This model simulates a symmetric pool to the energy market, which gets the market system price through the intersection of the aggregate supply and demand curve in which are represented all bids and offers of the market. The relaxation variables and their penalties are used to guarantee the problem convergence.

$$Minimize\ f = \min$$

$$\sum_{t=1}^{T}\left[\sum_{k=1}^{N_K}\sum_{r=1}^{N_R}\left(P_{S(r,k,t)}\times C_{S(r,k,t)}^{\max} + RLXD_{(k,t)}\times W_{RLXD(k,t)} + RLXU_{(k,t)}\times W_{RLXU(k,t)}\right) - \sum_{l=1}^{N_L} P_{b(l,t)}\times C_{b(l,t)}^{\max}\right] \tag{3.11}$$

The optimization problem includes the power balance and ancillary service capacity requirement constraints. Equation (3.12) refers to the power balance constraint for energy service (k=5) in each period *t*. The balance should consider the selling bids and the buying bids, plus the forecasted transmission losses. Since the model does not consider the technical constraints of the network, it was decided to allocate an amount of power related to forecasted losses. This constraint also includes the loads which do not participate in the market – designed by "rigid demand" [Soares-2011]. The rigid demand corresponds to consumers, in which their only goal is to be fed, regardless of the market clearing price. Usually, it is also referred to as consumer of last resource [Soares-2011]. The ISO must ensure the supply of the rigid demand.

$$\sum_{r=1}^{N_R} P_{S(r,k,t)}\times X_{S(r,k,t)} = \sum_{l=1}^{N_L} P_{b(l,t)}\times X_{L(l,t)} + P_{Rd(t)} + P_{loss(t)}$$
$$\forall t\in\{1,\dots,T\}; k=5 \tag{3.12}$$

The constraint referred to the power required by each ancillary service which must meet the minimum and maximum requirements imposed by the ISO for each service *k* in each period *t*, is the same as presented in the previous model represented by equation (3.2). Equations (3.13) and (3.14) represent the constraints concerning the minimum and maximum amount of generation offered by each resource *r* for each service *k*, (3.13), as well as the minimum and maximum quantity of load, that each buying agent submits for the energy market (3.14).

$$P_{S(r,k,t)}^{\min} \le P_{S(r,k,t)} \le P_{S(r,k,t)}^{\max}$$
$$\forall t \in \{1,...,T\}; \forall k \in \{1,...,N_K\}; \forall r \in \{1,...,N_R\} \tag{3.13}$$

$$P_{b(l,t)}^{\min} \le P_{b(l,t)} \le P_{b(l,t)}^{\max}$$
$$\forall t \in \{1,...,T\}; \forall l \in \{1,...,N_L\} \tag{3.14}$$

The AS methodology constraints are the same as in the previous model. In this regard, equations (3.4 to 3.9) are valid for this model.

Equation (3.15) represents the maximum upward limit of generators in energy and ancillary service capacity, for each resource *r*, in period *t*.

$$\sum_{k=2}^{N_K} P_{S(k,r,t)} \le P_{CAP(r,t)}$$
$$\forall t \in \{1,...,T\}; \forall k \in \{2,3,4,5\}; \forall r \in \{1,...,N_R\} \tag{3.15}$$

3.4. Joint Market model considering AS bidding regions

An energy and AS joint market simulation model considering different AS bidding regions is shown in this section. The model provides the AS dispatch for each AS region. An ancillary services region is a set of network buses, in which resources are capable of providing AS. All AS regions contemplates the same ancillary services.

This model contains a co-optimization of energy and AS and the offers exchange between services (RD, RU, SP and NS), based on CAISO market rules with an Alternate Current Optimal Power Flow (AC OPF). The proposed method considers a new approach to the problem in which the ancillary services and energy service compete for the use of the network branches, according to the players' bids. An advantage of this method over others is the use of an AC OPF, in which is considered the active and reactive power flow on the network to the dispatch problem of joint market. Another advantage of this model is the AS dispatch that is considered for regions of the network. This allows the ISO to have an increased safety in AS dispatch, by ensuring in case of fault of a large capacity generator. That is why there are ancillary services scenarios which can respond more easily to possible events of this kind [Soares-2013].

In order to solve the proposed problem is used a mixed-integer non-linear programming model.

3.4.1. Problem Description

In a simultaneous energy and AS joint market, the ISO optimizes the use of the transmission network by both energy and AS capacity. In CAISO, congestion management for AS is performed implicitly through the provision of regional AS requirements. The CAISO establishes ten AS regions. Each of these regions is a possible scenario for solving network congestion. Typically, all these scenarios are not used at the same time, because in most cases of network congestion, the congestions may be solved by strategically combining of certain scenarios. However, in certain infrequent events there may be network congestion in which it is imperative to use all the available scenarios. One part of these scenarios only considers the use of internal resources of the region, while other scenarios consider internal resources, as well as the inter-ties between other regions [CAISO-2011a].

This model proposes an energy and AS joint market, considering different AS bidding regions. The objective of the optimization is to minimize the energy and AS costs subject to the network and the resources participant in the market.

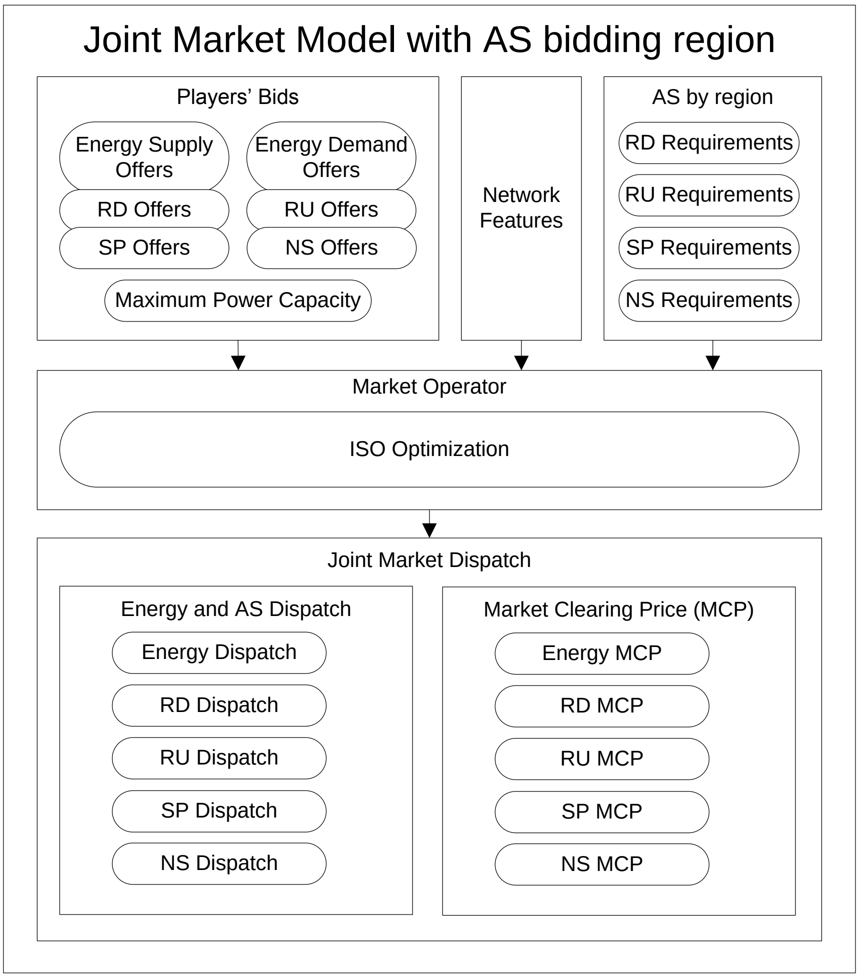

Figure 3.5 – Energy and AS joint market diagram considering AS bidding regions.

The model structure proposed to solve the problem is illustrated in detail in Figure 3.5. The optimization module has a complex optimization process, which considers all the constraints necessary to solve the problem.

The optimization process of this model is an evolution of the algorithm developed in section 3.3. The algorithm has the particularity of involving an AC OPF included in the optimization of the energy and AS joint market, where the AS procurement performed by the ISO is done by network regions.

The optimization module solves the problem formulated in the following subsection. The results refer to the energy and AS dispatch, as well as the Locational Marginal Price, which is obtained in each node for each time period from the optimal commitment and scheduling results.

3.4.2. Mathematical Formulation

The problem presented considers the mathematical formulation described in this section and aims the optimization of available resources in the various aspects of the energy and AS joint market. Through this mathematical formulation, the ISO is able to optimize the energy and AS procurement simultaneously and to use a MINLP model to solve the problem. The formulation allows the cascading of a high quality AS for a lower quality one (for example, Regulation Up to Spinning Reserve). The rational procurement behavior dictates that such substitution should be allowed and should lead to lower overall procurement costs.

The objective function presented in (3.16) is formulated with the objective of finding the total minimal cost considering the co-optimization of energy and AS market offers. To ensure the problem convergence, the relaxation variables and their respective penalties are used.

$$Minimize\ f = \min$$

$$\sum_{t=1}^{T}\left[\sum_{k=1}^{N_K}\sum_{r=1}^{N_R}\left(P_{S(r,k,t)} \times C_{S(r,k,t)}^{\max} + RLXD_{(k,t)} \times W_{RLXD(k,t)} + RLXU_{(k,t)} \times W_{RLXU(k,t)}\right) - \sum_{l=1}^{N_L} P_{b(l,t)} \times C_{b(l,t)}^{\max}\right] \tag{3.16}$$

Equation (3.17) refers to the active power balance constraint (Kirchhoff's first law) in each bus *i*, for each period *t*.

$$\begin{gathered}
V_{i(t)}^2 \times G_{ii} + V_{i(t)} \times \sum_{j \in y^i} V_{j(t)}\left(G_{ij}\cos\left(\theta_{i(t)} - \theta_{j(t)}\right) - B_{ij}\sin\left(\theta_{i(t)} - \theta_{j(t)}\right)\right) = P_{Gi(t)} - P_{Di(t)} \\
P_{Gi(t)} = \sum_{r=1}^{N_R^i}\sum_{k=2}^{N_K^R} P_{S(r,k,t)}^i \times X_{S(r,k,t)} \\
P_{Di(t)} = \sum_{l=1}^{N_L^i} P_{b(l,t)}^i \times X_{L(l,t)} \\
\forall t \in \{1,...,T\}; \forall i \in \{1,...,N_B\}; \forall k \in \{2,3,4,5\}
\end{gathered} \tag{3.17}$$

Equation (3.18) refers to the reactive power balance constraint for energy service (*k*=5) in each bus *i*, for each period *t*.

$$
\begin{aligned}
&V_{i(t)} \times \sum_{j\in y^i} V_{j(t)} \left(G_{ij} \sin\left(\theta_{i(t)} - \theta_{j(t)}\right) - B_{ij} \cos\left(\theta_{i(t)} - \theta_{j(t)}\right)\right) - V_{i(t)}^2 \times B_{ii} = Q_{Gi(t)} - Q_{Di(t)} \\
&Q_{Gi(t)} = \sum_{r=1}^{N_R^i} Q_{S(r,k,t)}^i \times X_{S(r,k,t)} \\
&Q_{Di(t)} = \sum_{l=1}^{N_L^i} Q_{b(l,t)}^i \times X_{L(l,t)} \\
&\forall t \in \{1,\dots,T\}; \forall i \in \{1,\dots,N_B\}; k = 5
\end{aligned}
\qquad (3.18)
$$

Bus voltage magnitude and angle limits are represented in equation (3.19). To the slack bus, the voltage angle and magnitude are fixed and defined to the user.

$$
\begin{aligned}
&V_{i(t)}^{\min} \le V_{i(t)} \le V_{i(t)}^{\max} \\
&\theta_{i(t)}^{\min} \le \theta_{i(t)} \le \theta_{i(t)}^{\max} \\
&\forall t \in \{1,\dots,T\}; \forall i \in \{1,\dots,N_B\}
\end{aligned}
\qquad (3.19)
$$

The line thermal limits constraint is essential to restrict the power flow that flows in each network line and is given by equation (3.20).

$$
\begin{aligned}
&\left| \overline{U_{i(t)}} \times \left[\overline{y_{ij}} \times \left(\overline{U_{i(t)}} - \overline{U_{j(t)}} \right) + \overline{y_{sh\_i}} \times \overline{U_{i(t)}} \right]^* \right| \le S_{L_y}^{\max} \\
&\left| \overline{U_{j(t)}} \times \left[\overline{y_{ij}} \times \left(\overline{U_{j(t)}} - \overline{U_{i(t)}} \right) + \overline{y_{sh\_i}} \times \overline{U_{j(t)}} \right]^* \right| \le S_{L_y}^{\max} \\
&\forall t \in \{1,\dots,T\}; \forall i,j \in \{1,\dots,N_B\}; i \ne j; \forall y \in \{1,\dots,N_Y\}
\end{aligned}
\qquad (3.20)
$$

The constraint concerning the minimum and maximum amount of active power generation offered by each resource for service *k* is the same as presented in the previous model represented by equation (3.13). Moreover, equation (3.21) represents the constraint, which considers the minimum and maximum amount of reactive power generation that each resource must provide depending on the active power generation supplied by himself for energy service (*k*=5). The constraint which considers the maximum and minimum quantity of load that each buying agent submits is the same as the one presented in the previous model, represented by equation (3.14). Equation (3.22) represents the active power required by each AS region *z* that must meet the minimum and maximum requirements imposed by the ISO for each AS region *z* and service *k*, in each period *t*.

$$
\begin{aligned}
&Q_{S(r,k,t)}^{\min} \le Q_{S(r,k,t)} \le Q_{S(r,k,t)}^{\max} \\
&Q_{S(r,k,t)}^{\max} = P_{S(r,k,t)}^{\max} \times F_{power(r,t)} \\
&\forall t \in \{1,\dots,T\}; k = 5; \forall r \in \{1,\dots,N_R\}
\end{aligned}
\qquad (3.21)
$$

$$
\begin{aligned}
&R_{AS(k,t)}^{\min;\ z} \le R_{AS(k,t)}^{z} \le R_{AS(k,t)}^{\max;\ z} \\
&\forall t \in \{1,\dots,T\}; \forall k \in \{1,\dots,N_K\}; \forall z \in \{1,\dots,N_Z\}
\end{aligned}
\qquad (3.22)
$$

Regulation Down constraint is represented by equation (3.23), which establishes the regional dispatch of the generators for this ancillary service (*k*=1) for each period *t*. For every AS requirement related to a specific region *z*, both internal resources of the region *z*, as well as external resources of the regions *w* may participate in this service.

$$\begin{gathered} R^{z}_{AS(k,t)} = \sum_{r=1}^{N_R^z} P^{z}_{S(r,k,t)} \times X^{z}_{S(r,k,t)} + \sum_{r=1}^{N_R^w} P^{w}_{S(r,k,t)} \times X^{w}_{S(r,k,t)} \\ \forall t \in \left\{1,...,T\right\}; k=1; \forall z \text{ and } \forall w \in \left\{1,...,N_Z\right\}; w \neq z \end{gathered} \tag{3.23}$$

Regional Regulation Up (*k*=2) constraint is represented by equations (3.24) and (3.25). The ancillary service cascading is considered. Relaxation variables are used for cases where the generators participants in the market cannot meet the AS requirement, to ensure the continuity of RU service in period *t*. Assuming that the service is dispatched in a particular region *z*, the resources of other regions *w* of the network can participate in the dispatch of region *z*, since the dispatch of region *w* is ensured and the resource has the capacity to provide in the service of region *z* without violating the network congestion constraints.

$$\begin{gathered} R^{z}_{AS(k,t)} = \sum_{r=1}^{N_R^z} P^{z}_{S(r,k,t)} \times X^{z}_{S(r,k,t)} + \sum_{r=1}^{N_R^w} P^{w}_{S(r,k,t)} \times X^{w}_{S(r,k,t)} + RLXD_{(z,k,t)} - RLXU_{(z,k,t)} \\ \forall t \in \left\{1,...,T\right\}; k=2; \forall z \text{ and } \forall w \in \left\{1,...,N_Z\right\}; w \neq z \end{gathered} \tag{3.24}$$

$$\begin{gathered} R^{z}_{AS(k,t)} - SLCK^{RU\_SP}_{(z,t)} - SLCK^{RU\_NS}_{(z,t)} \geq R^{\min;\ z}_{AS(k,t)} \\ \forall t \in \left\{1,...,T\right\}; k=2; \forall z \in \left\{1,...,N_Z\right\} \end{gathered} \tag{3.25}$$

Equations (3.26) and (3.27) represent the regional Spinning Reserve (*k*=3) constraints. Following the same constraints in the regional RU service, SP constraints are similar with the difference that the SP can only be used in cascade with Non-Spinning reserve in each region *z*, for each period *t*.

$$\begin{gathered} R^{z}_{AS(k,t)} = \sum_{r=1}^{N_R^z} P^{z}_{S(r,k,t)} \times X^{z}_{S(r,k,t)} + \sum_{r=1}^{N_R^w} P^{w}_{S(r,k,t)} \times X^{w}_{S(r,k,t)} + RLXD_{(z,k,t)} - RLXU_{(z,k,t)} + SLCK^{RU\_SP}_{(z,t)} \\ \forall t \in \left\{1,...,T\right\}; k=3; \forall z \text{ and } \forall w \in \left\{1,...,N_Z\right\}; w \neq z \end{gathered} \tag{3.26}$$

$$\begin{gathered} R^{z}_{AS(k,t)} - SLCK^{SP\_NS}_{(z,t)} \geq R^{\min;\ z}_{AS(k,t)} \\ \forall t \in \left\{1,...,T\right\}; k=3; \forall z \in \left\{1,...,N_Z\right\} \end{gathered} \tag{3.27}$$

Equation (3.28) refers to the constraint of Non-Spinning reserve by regions, which allows the RU and SP of the same region to participate in the regional NS service for each period *t*.

$$R_{AS(k,t)}^{z} = \begin{bmatrix} \sum_{r=1}^{N_R^z} P_{S(r,k,t)}^{z} \times X_{S(r,k,t)}^{z} + \sum_{r=1}^{N_R^w} P_{S(r,k,t)}^{w} \times X_{S(r,k,t)}^{w} \\ +RLXD_{(z,k,t)} - RLXU_{(z,k,t)} + SLCK_{(z,t)}^{RU\_NS} + SLCK_{(z,t)}^{SP\_NS} \end{bmatrix} \tag{3.28}$$

$$\forall t \in \{1,...,T\}; k = 4; \forall z \text{ and } \forall w \in \{1,..., N_Z\}; w \neq z$$

The maximum upward limit constraint of resources in ancillary service and energy capacity, for each resource *r* and period *t* is the same as presented in the previous model represented by equation (3.15).

Equation (3.29) illustrates the constraint in which for each region and ancillary service, internal resources of a given region and ancillary service must ensure at least percentage factor of the regional AS requirement. This rule is ensured by the variable percentage factor of the regional AS requirement.

$$\sum_{r=1}^{N_R^z} P_{S(r,k,t)}^{z} \times X_{S(r,k,t)}^{z} \geq R_{AS(k,t)}^{z} \times F_{AS\_req(z,k)} \tag{3.29}$$

$$\forall t \in \{1,...,T\}; \forall k \in \{1,2,3,4\}; \forall z \in \{1,..., N_Z\}$$

3.5. Joint Market model considering Bialek coefficients

This section proposes energy and AS joint market simulation model which includes the use of an AC OPF to determine the network power flow. The power flow considers all services available on the market which may cause network congestion (namely, energy, Regulation Up, Spinning Reserve and Non-Spinning Reserve). In order to simulate the congestion that each service imposes on the network, a complex and innovative simulation method was developed based on the methodology of topological factors developed by Bialek.

This methodology is crucial for the joint market simulation, as that ensures always a technically and economically feasible and viable solution. Many real markets, during the initial process of day-ahead market do not proceed to the technical validation of the economic dispatch obtained for the energy and AS. Only later the technical validation of the dispatch and its respective adjustments is undertaken. The developed methodology proceeds simultaneously to the energy and AS dispatch, ensuring the viability of technical dispatches. Thus, it is ensured that the simulated dispatches are perfectly feasible.

The proposed model mechanism and its simulation processes are discussed and explained in this section. The proposed model consists essentially in four distinct simulation phases. The first corresponds to the energy dispatch and consequent determination of Bialek factors. The second, concerns the simultaneous energy and RU dispatch, based on generation limits calculated via the topological factors in the previous phase. The third step is intended for simultaneous simulation of energy, RU and SP services, considering the factors calculated in the previous phase. Finally, the fourth and last phase claims the joint simulation of all services based on simulations of the previous phases.

3.5.1. Problem Introduction

In a simultaneous energy and AS joint market, the ISO optimizes the use of the transmission network by both energy and AS capacity. This model proposes the use of a method to solve the network congestion by establishing the energy and AS dispatch in a shared way according to the favorable lines congestion.

This way, the energy service must have greater importance in the use of line capacity of the network, i.e., the power flow related to the energy service should have greater influence in the use of network branches, followed by the RU reserve, the SP reserve service, and finally the NS reserve service. This hierarchical nature refers to the importance that each service has on the network. Therefore, the proposed simulation model to solve the network congestion will have to understand and respect the hierarchy of the system.

In this context, the method implemented in the model is based on the proportional sharing, which is a method for calculating the sharing that each generator has in the network lines. The method satisfies the Kirchhoff's Current Law. It assumes that the network node is a perfect mixer of incoming flows. Moreover, the principle is fair as it treats all incoming and outgoing flows in the same way [Bialek-1996, Bialek-1997 and Su-2001]. The main principle used to trace the flow of electricity is illustrated in Figure 3.6, in which two of the four lines are inflows and the other two lines are outflows.

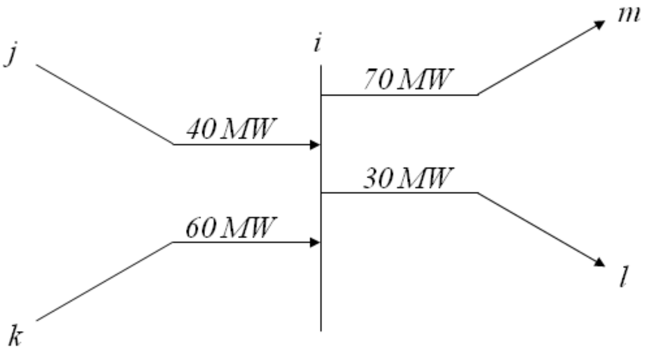

Figure 3.6 – Proportional sharing principle, adapted from [Bialek-1997].

The total power flow through bus *i* is 40 MW + 60 MW = 100 MW of which 70% is supplied by outflows to line *i-m* and 30% to line *i-l*. It is assumed that each MW leaving the bus contains the same proportion of inflows. Hence the 70 MW outflowing in line *i-m* consists in the following proportions:

$$\frac{40\ MW}{40\ MW + 60\ MW} \times 70\ MW = 28\ MW$$

Supplied by line *j-i*, and

$$\frac{60\ MW}{40\ MW + 60\ MW} \times 70\ MW = 42\ MW$$

Supplied by line *k-i*. In same direction, the sharing for the line *i-l* are as follows:

$$\frac{40\ MW}{40\ MW + 60\ MW} \times 30\ MW = 12\ MW$$

Supplied by line *j-i*, and

$$\frac{60\ MW}{40\ MW + 60\ MW} \times 30\ MW = 18\ MW$$

Supplied by line *k-i*.

The Proportional Sharing principle treats all the incoming and outflowing flows in the same way.

A topological distribution factors for generation and load was proposed in [Bialek-1997] in order to apply the method at a computer level to facilitate the calculation of the sharing factors of generators in network lines and loads. The method determine the generators which are supplying a particular load, the amount of each generator is making of a transmission/distribution line and what is the contribution of each generator's to the system losses. The method is not limited to incremental changes and is applicable for both active and reactive power. This method starts from a power flow solution; the first step of the method is to identify the buses reached by the power produced of each generator; then it determines the sets of buses supplied by the same generators. Through the proportional sharing assumption, it is then possible to calculate the contribution of each generator to the loads and flows.

3.5.2. Problem Description

The method presented in the previous subsection can be integrated into the simulation model of energy and AS joint market in order to prevent congestion problems of the lines by limiting the generation capacity of each individual generator at the level of energy and AS dispatch.

The model structure proposed to solve the problem is illustrated in detail in Figure 3.7. The optimization module has a complex optimization process, which considers all the constraints necessary to solve the problem. In the optimization module, the algorithm presents a general view of the problem.

In order to better understand the algorithm implemented, the flowchart illustrating the functioning of the algorithm developed to solve the problem is explained step by step. The methodology for solving the problem starts by optimizing the energy service (first step). This first step consists in the energy resources dispatch for energy service in order to get the power flow which flows in the network. After the power flow and generators dispatch determination, one can obtain the Bialek topological factors. As described above, through the Bialek factors it is possible to obtain the sharing that each generator has in the network power flow, as well as the sharing of each generator has to feed the load (second step). This makes it possible to determine the maximum generation that each generator can provide for the energy service, ensuring that the energy service dispatch is feasible (third step).

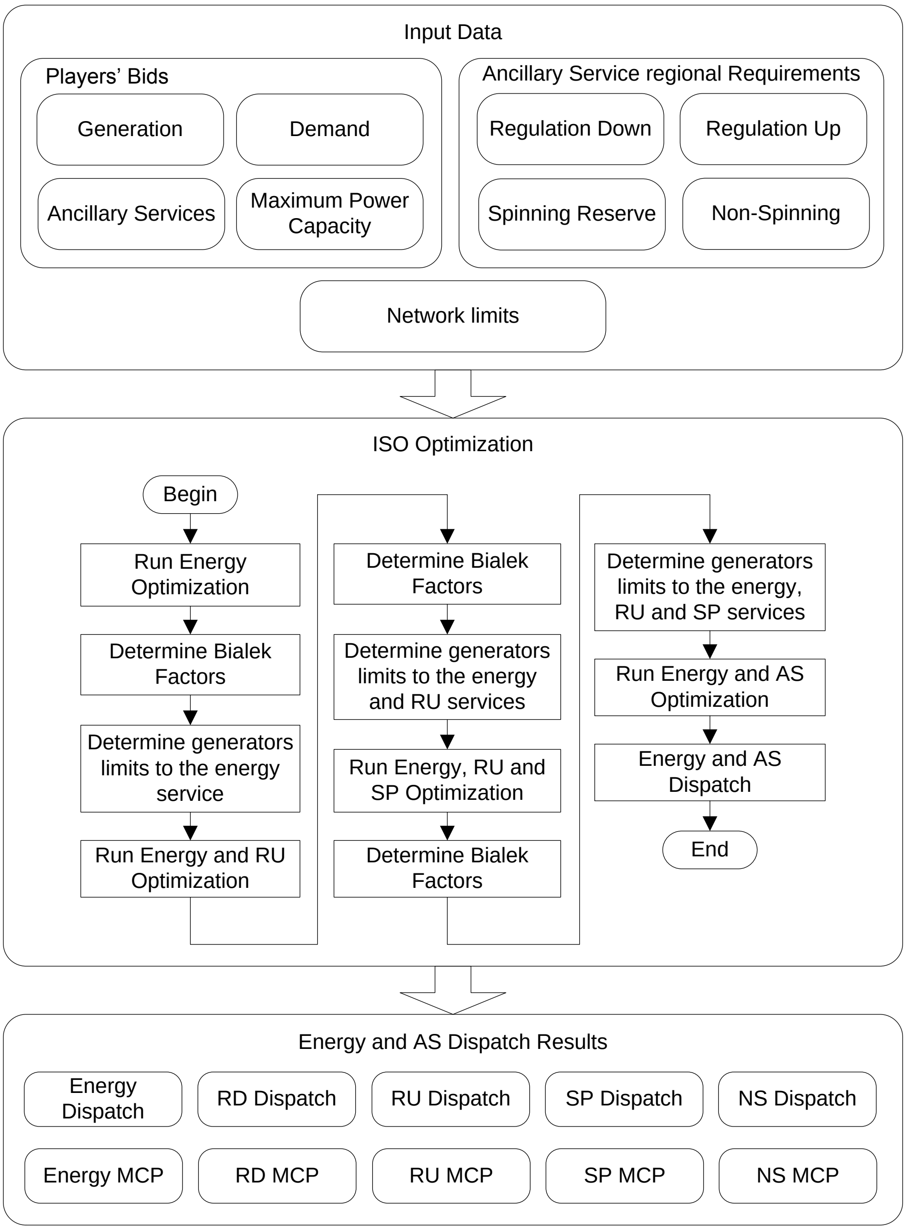

Figure 3.7 – Energy and AS joint market diagram considering Bialek topological factors.

Based on the determined limits, one can perform the energy, Regulation Down and Regulation Up joint optimization. The RD service, for its particular features, does not cause congestion in the network, since it is a service indicated for the reduction of energy production and consecutive decrease in the network power flow; the RD service is calculated simultaneously with the RU service. Knowing that the contribution that each generator can provide for the energy service is limited by the previous step, it ensures that the energy and RU joint optimization do not violate the thermal limitations of the network branches.

In the fifth step, with the data related to the energy and RU dispatch and its power flow, the Bialek factors are again calculated. After the conclusion of the Bialek factors determination, it is estimated the contributions that each generator has in the network power flow for the energy and RU service, i.e., it is determined the maximum generation that each generator can provide in the energy and RU joint service optimization (sixth step).

The seventh step is the energy, RU and SP joint optimization. In this optimization process, the sum of the energy and RU dispatch for each generator is restricted to the limits calculated in the previous step. Besides this constraint, the generators are limited by the other constraint determined in the third step of the algorithm (corresponding to the maximum limit of each generator production for the energy service). The eighth step consists in determining the Bialek factors in the energy, RU and SP joint optimization (seventh step). The ninth step is the determination of the sharing that each generator has in the network power flow on the energy, RU and SP joint optimization in order to conceive the maximum generation limits that each generator can dispatch.

The tenth step refers to the energy and all ancillary services joint optimization. In the simulation process, the maximum limits that each generator can dispatch according to previous simulations of energy and ancillary services are considered. This way, this optimization includes constraints related to the third, sixth and ninth steps. Thus, the dispatch obtained in the previous step reflects the final dispatch of energy and ancillary services, being perfectly feasible.

This model of energy and ancillary services optimization supported by the topological methodology developed by Bialek, provides credible simulations for the joint market in what is considered real constraints related to the physical characteristics of the transport and distribution of electricity. All constraints considered in this model are presented at a very detailed level in the next subsection.

3.5.3. Mathematical Formulation

The proposed problem formulation considers the energy and AS market simulation in a liberalized environment.

The formulation includes the use of method to identify the contribution of each unit generation on the network branches congestion. Based on this method, it is possible to simulate each energy and AS dispatch, ensuring that the schedule dispatch is feasible. In order to achieve a proper and adequate perception of the implied formulation problem in this section it is exposed the formulation engaging the entire problem discussed in the introduction section of the problem.

The algorithm presented below for the calculation of generators sharing in the active power flow of each network branch is based on the example discussed in the introductory section of the problem of topological Bialek factors.

Therefore, the following equations are fundamental for solving the problem. The sum of the actual demand of a particular load, plus the allocated part of the total transmission loss is referred to as the gross demand. Assuming that P_i^g is an unknown gross nodal power flow through node *i*, and P_{ij}^g is an unkown gross line flow in line *i-j*, the gross power balance equation at node *i*, when looking at the inflows is defined as [Bialek-1997]:

$$P_i^g = \sum_{j \in \alpha_i^u} \left| P_{ij}^g \right| + P_{Gi} \qquad \forall i \in \{1, \ldots, N_B\} \tag{3.30}$$

Where α_i^u is set of nodes supplying directly the node and P_{Gi} is the generation in node *i*. As$|P_{ij}^g| = |P_{ji}^g|$, the flow $|P_{ij}^g|$ can be replaced by$\left(|P_{ji}^g|/P_j^g\right) \times P_j^g$. If the transmission losses are small, it can be assumed that$|P_{ji}^g|/P_j^g \cong |P_{ji}|/P_j$, where P_{ji} is the actual flow from node *j* in line *j-i* and P_j is the actual total flow through node *j*. Under this assumption equation (3.30) can be rewritten as presented in equation (3.31) or (3.32):

$$P_i^g - \sum_{j \in \alpha_i^u} \frac{\left| P_{ij}^g \right|}{P_j} \times P_j^g = P_{Gi} \qquad \forall i \in \{1, \ldots, N_B\} \tag{3.31}$$

$$A_u \times P_{gross} = P_G \tag{3.32}$$

Where P_{gross} is the unknown vector of gross nodal flows, P_G is the vector of nodal generations and the distribution matrix. This matrix is sparse and non-symmetric with its (*i,j*) elements equal to: 1 for *i=j*; $-|P_{ji}|/P_j$ for $j \in \alpha_i^u$. If there is A_u^{-1} then $P_{gross} = A_u^{-1} \times P_G$ and its element is presented in the next equation. This equation shows how *i*-th gross nodal power is supplied from all the generators in the system.

$$P_i^g = \sum_{r=1}^{N_B} \left[A_u^{-1} \right]_{ir} \times P_{Gr} \tag{3.33}$$

The gross outflow in line i-j can be calculated, using the proportional sharing, as presented in the equation (3.34).

$$P_{ij}^g = \frac{P_{ij}^g}{P_i^g} \times P_i^g = \frac{P_{ij}^g}{P_i^g} \times \left[A_u^{-1} \right]_{ir} \times P_{Gr} = \sum_{r=1}^{N_B} D_{ij,r}^g \times P_{Gr} \qquad j \in \alpha_i^d \tag{3.34}$$

In the equation, α_i^d is the set of nodes supplied directly from node *i* and $D_{ij,r}^g = \left(P_{ij}^g / P_i^g\right) \times [A_u^{-1}]_{ir}$. This equation represents the topological generation distribution factor that is a portion of generation due to *r*-th generator that flows in line *i-j*.

Standard formulation for preventing congestion on a energy and ancillary services basis.

This algorithm is used to calculate the generator sharing in each network branch. In this way, the calculation of the limits necessary to restrict generation of each generator was developed as follows:

$$P_{energy\_\lim(r,t)} = P_{S(r,k,t)}^i + \sum_{j \in \alpha_i^d}^{N_B} \left(\left(P_{Ly(i,j)}^{\max} - P_{ij} \right) \times \frac{P_{ij}^{g(r)}}{P_{Ly(i,j)}^{\max}} \right) \tag{3.35}$$
$$\forall t \in \{1,...,T\}; \forall i \in \{1,...,N_B\}; \forall r \in \{1,...,N_R\}; k = 5$$

$$P_{energy\_RU\_\lim(r,t)} = \sum_{k=2}^{N_r^k} P_{S(r,k,t)}^i + \sum_{j \in \alpha_i^d}^{N_B} \left(\left(P_{Ly(i,j)}^{\max} - P_{ij} \right) \times \frac{P_{ij}^{g(r)}}{P_{Ly(i,j)}^{\max}} \right) \tag{3.36}$$
$$\forall t \in \{1,...,T\}; \forall i \in \{1,...,N_B\}; \forall r \in \{1,...,N_R\}; \forall k \in \{2,5\}$$

$$P_{energy\_RU\_Spinning\_\lim(r,t)} = \sum_{k=2}^{N_r^k} P_{S(r.k,t)}^i + \sum_{j \in \alpha_i^d}^{N_B} \left(\left(P_{Ly(i,j)}^{\max} - P_{ij} \right) \times \frac{P_{ij}^{g(r)}}{P_{Ly(i,j)}^{\max}} \right) \tag{3.37}$$
$$\forall t \in \{1,...,T\}; \forall i \in \{1,...,N_B\}; \forall r \in \{1,...,N_R\}; \forall k \in \{2,3,5\}$$

The equations (3.35), (3.36) and (3.37) refer to the calculation of the limits imposed in the simulation model joint market for resources *r*. $P_{S(r,k,t)}^i$ is the effective dispatch of resource *r* obtained in the simulation market, for service *k* in each period *t*. $P_{Ly(i,j)}^{max}$ is the maximum capacity of active power in line *i-j*. P_{ij} refers to the power flow in line *i-j*. $P_{ij}^{g(r)}$ refers to the sharing of power generated by resource *r* on the line *i-j*.

3.6. Joint Market model applied by VPP

The continued increase of DER penetration in distribution systems raises the need to adopt new market models which considers the particular characteristics of the inherent resources in distribution systems.

In this context, the concept of VPP is important as it allows the aggregation of DER (mainly composed of DG, DR and storage units). Therefore, the VPP optimal management of its resources may enable small players to participate in the market with low risk related to their bids. Thus, the VPPs are able to participate and organize a variety of available markets such as the energy and AS markets.

The AS applied to the Smart Grid concept, in the scope of the distribution network is still a subject under study. However, some authors have theories about AS best suited to be traded in the market, as well as the development of new AS suited to a distribution network in order to ensure system stability [Braun-2007, Buehner-2010].

In this context, this section proposes an energy and AS joint market model which considers the several players aggregated by VPPs. This model enables the VPP optimization of its resources and the trading between them and the small players. In order to perform such trade, complex contracts were designed to allow both players and VPPs to trade between them with special conditions established in the contracts.

3.6.1. Problem Description

The energy and AS joint market simulation problem in the context of the distribution system behaves identically to that established for the transmission system. Thus, any methodology developed in this section contemplates the methodology developed in the previous model in order to ensure always a viable and feasible solution of the energy and AS dispatches.

The methodology developed in this section includes the bidding of ancillary services for regions of the network, based on several resources technologies, in which the DR programs and storage charge and discharge bids are included. Besides this, the relaxation variables are considered in each region of the distribution system.

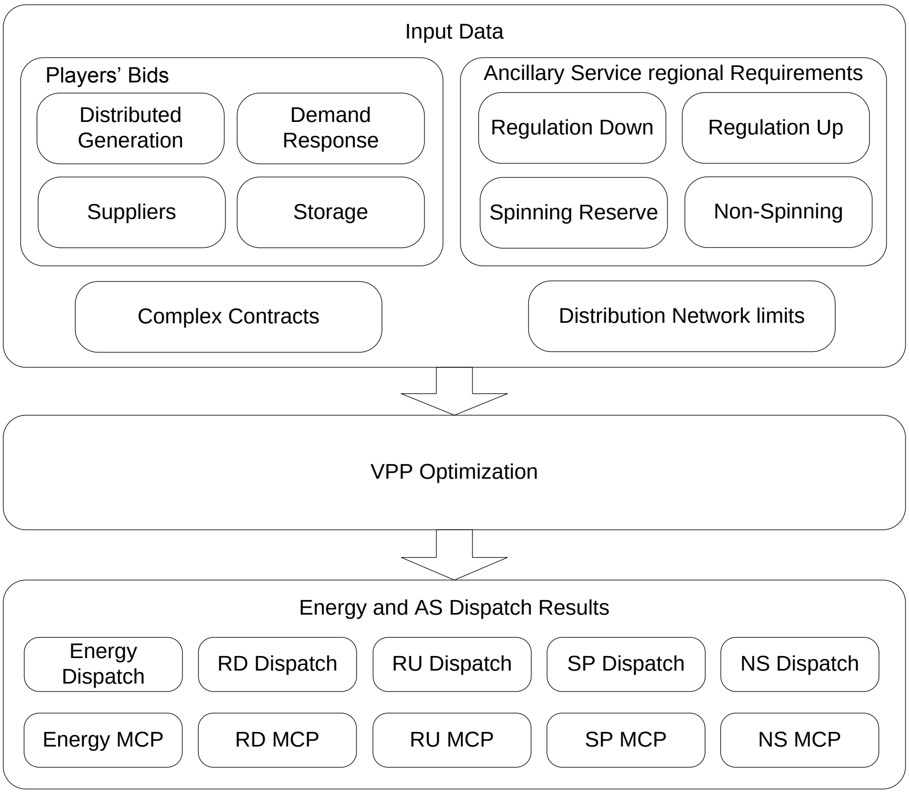

Figure 3.8 – Energy and AS joint market diagram in distribution systems.

Complex contracts are considered in the scope of the energy dispatch, in order to enable a greater range of trading between players and the VPP. The architecture of the developed model is illustrated in Figure 3.8. The input data module comprises all kinds of players bids, the conditions related to complex contracts, technical data relating to the distribution network, and AS requirements previously established by the VPP.

The VPP optimization module is based on the optimization model of section 3.5 with the inclusion of constraints related to the model presented in this section.

The results module illustrates the dispatches of each service inherent to market model and its market clearing prices.

3.6.2. Mathematical Formulation

The proposed problem formulation considers the use of market aggregator's agents (VPPs) for the management of several type of resource in the network. Through contracts between the VPP and the players, the VPP has a total ability to manage the aggregated players' resources, in order to ensure the control and stability of the network. The VPP are capable of aggregate all kind of DER, mainly DG based on renewable energy resources, and other DER, including DR and storage units. In this way, through the formulation the VPP can simulate the management according to its objectives.

The model allows trading between players and VPPs based on complex contracts which may be beneficial for small players that could participate in the market through the aggregation of a VPP, and also be beneficial for the VPP to ensure the aggregation of players that gives the best benefits in its optimal management.

The objective function presented in (3.38) has the main goal of minimizing the VPP operation costs taking into account several kinds of complex contracts between the VPP and the players, while satisfying the consumer needs. The following costs are separated into two distinct parts: energy and ancillary services.

$$Minimize \ f = \min$$

$$\sum_{t=1}^{T}\left(F_{E(t)} + \sum_{k=1}^{4} F_{AS(k,t)} \right) \tag{3.38}$$

Equation (3.39) shows the objective function costs concerning the energy part, in which are considered the following costs: DG costs, costs with energy acquisition to external suppliers, storage discharge and charge costs, DR program costs for reduction and curtailment, costs of Non-Supplied Demand (NSD) and Generation Curtailment Power (GCP) costs for DG units.

$$
\begin{aligned}
&F_{E(t)} = \\
&\sum_{SP=1}^{N_{SP}} P_{SP(SP,k,t)} \times C_{SP(SP,k,t)} + \sum_{DG=1}^{N_{DG}} P_{DG(DG,k,t)} \times C_{DG(DG,k,t)} + \\
&\sum_{l=1}^{N_L} P_{DR\_A(l,k,t)} \times C_{DR\_A(l,k,t)} + \sum_{l=1}^{N_L} P_{DR\_B(l,k,t)} \times C_{DR\_B(l,k,t)} + \\
&\sum_{DG=1}^{N_{DG}} P_{GCP(DG,t)} \times C_{GCP(DG,t)} + \sum_{S=1}^{N_S} P_{Dch(S,k,t)} \times C_{Dch(S,k,t)} - \\
&\sum_{S=1}^{N_S} P_{Ch(S,k,t)} \times C_{Ch(S,k,t)} + \sum_{l=1}^{N_L} P_{NSD(l,k,t)} \times C_{NSD(l,k,t)} \\
&\forall t \in \left\{1,...,T\right\}; \forall k = 5
\end{aligned}
\tag{3.39}
$$

The objective function costs concerning the ancillary services parts contain some differences when compared to the energy part. The costs associated with ancillary services are represented in equation (3.40) and they are: DG costs, costs with power acquisition to external suppliers, storage discharge and charge costs, DR program costs for reduction and curtailment and relaxation variables penalties.

$$
\begin{aligned}
&F_{AS(k,t)} = \\
&\sum_{SP=1}^{N_{SP}} P_{SP(SP,k,t)} \times C_{SP(SP,k,t)} + \sum_{DG=1}^{N_{DG}} P_{DG(DG,k,t)} \times C_{DG(DG,k,t)} + \\
&\sum_{l=1}^{N_L} P_{DR\_A(l,k,t)} \times C_{DR\_A(l,k,t)} + \sum_{l=1}^{N_L} P_{DR\_B(l,k,t)} \times C_{DR\_B(l,k,t)} + \\
&\sum_{z=1}^{N_Z} RLXD_{(z,k,t)} \times W_{RLXD(z,k,t)} + \sum_{z=1}^{N_Z} RLXU_{(z,k,t)} \times W_{RLXU(z,k,t)} + \\
&\sum_{S=1}^{N_S} P_{Dch(S,k,t)} \times C_{Dch(S,k,t)} + \sum_{S=1}^{N_S} P_{Ch(S,k,t)} \times C_{Ch(S,k,t)} \\
&\forall t \in \left\{1,...,T\right\}; \forall k \in \left\{1,2,3,4\right\}
\end{aligned}
\tag{3.40}
$$

Equation (3.41) refers to the active power balance constraint (Kirchhoff's first law) in each bus *i*, including ancillary services *k*, for each period *t*.

$$
\begin{aligned}
&V_{i(t)}^2 \times G_{ii} + V_{i(t)} \times \sum_{j \in y^i} V_{j(t)} \left(G_{ij} \cos\left(\theta_{i(t)} - \theta_{j(t)}\right) - B_{ij} \sin\left(\theta_{i(t)} - \theta_{j(t)}\right) \right) = P_{Gi(t)} - P_{Di(t)} \\
&P_{Gi(t)} = \sum_{DG=1}^{N_{DG}^i} \sum_{k=2}^{N_K^{DG}} P_{DG(DG,k,t)}^i + \sum_{SP=1}^{N_{SP}^i} \sum_{k=2}^{N_K^{SP}} P_{SP(SP,k,t)}^i - \sum_{DG=1}^{N_{DG}^i} P_{GCP(DG,t)}^i \\
&+ \sum_{S=1}^{N_S^i} \sum_{k=2}^{N_K^S} P_{Dch(S,k,t)}^i + \sum_{l=1}^{N_L^i} \sum_{k=2}^{N_K^L} \left(P_{DR\_A(l,k,t)}^i + P_{DR\_B(l,k,t)}^i \right) \\
&P_{Di(t)} = \sum_{l=1}^{N_L^i} P_{Load(l,t)}^i + \sum_{S=1}^{N_S^i} \left(\sum_{k=5}^{N_K^S} P_{Ch(S,k,t)}^i - \sum_{k=1}^{4} P_{Ch(S,k,t)}^i \right) - \sum_{l=1}^{N_L^i} \sum_{k=5}^{N_K^L} P_{NSD(l,k,t)}^i + \sum_{l=1}^{N_L^i} \sum_{k=2}^{N_K^L} P_{req\_limit(l,k,t)}^i \\
&\forall t \in \left\{1,...,T\right\}; \forall i \in \left\{1,...,N_B\right\}; \forall k \in \left\{2,3,4,5\right\}
\end{aligned}
\tag{3.41}
$$

Equation (3.42) refers to the reactive power balance constraint for energy service (*k*=5) in each bus *i*, for each period *t*.

$$\begin{aligned}
&V_{i(t)} \times \sum_{j \in y^i} V_{j(t)} \left(G_{ij} \sin\left(\theta_{i(t)} - \theta_{j(t)}\right) - B_{ij} \cos\left(\theta_{i(t)} - \theta_{j(t)}\right)\right) - V_{i(t)}^2 \times B_{ii} = Q_{Gi(t)} - Q_{Di(t)} \\
&Q_{Gi(t)} = \sum_{DG=1}^{N_{DG}^i} Q_{DG(DG,k,t)}^i + \sum_{SP=1}^{N_{SP}^i} Q_{SP(SP,k,t)}^i \\
&Q_{Di(t)} = \sum_{l=1}^{N_L^i} Q_{Load(l,k,t)}^i - \sum_{l=1}^{N_L^i} Q_{NSD(l,k,t)}^i \\
&\forall t \in \{1,...,T\}; \forall i \in \{1,...,N_B\}; k = 5
\end{aligned} \tag{3.42}$$

Bus voltage magnitude and angle limits are the same as presented in the previous model represented by equation (3.19). The line thermal limits constraint is the same as presented in the previous model represented by equation (3.20).

The constraint concerning the minimum and maximum amount of active power generation offered by each external supplier for service *k* is represented on equation (3.43). Equation (3.44) concerns the reactive power limits for each supplier. This equation also considers the reactive power percentage factor regarding the active power. This implies that each resource is related to a generation limit of reactive power, according to its active power limit. In the same perspective, equations (3.45) and (3.46) refer to the minimum and maximum active and reactive power generation offered by DG units.

$$\begin{aligned}
&0 \le P_{SP(SP,k,t)} \le P_{SPMax(SP,k,t)} \\
&\forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\}; \forall k \in \{1,...,N_K\}
\end{aligned} \tag{3.43}$$

$$\begin{aligned}
&0 \le Q_{SP(SP,k,t)} \le Q_{SPMax(SP,k,t)} \\
&\forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\}; k = 5 \\
&Q_{SPMax(SP,k,t)} = P_{SPMax(SP,k,t)} \times F_{power(SP,t)} \\
&\forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\}; k = 5
\end{aligned} \tag{3.44}$$

$$\begin{aligned}
&P_{DGMin(DG,k,t)} \times X_{DG(DG,k,t)} \le P_{DG(DG,k,t)} \le P_{DGMax(DG,k,t)} \times X_{DG(DG,k,t)} \\
&\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; \forall k \in \{1,...,N_K\} \\
&P_{DG(DG,k,t)} + P_{GCP(DG,t)} \le P_{DGMax(DG,k,t)} \times X_{DG(DG,k,t)} \\
&\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; \forall k \in \{1,...,N_K\}
\end{aligned} \tag{3.45}$$

$$\begin{aligned}
&Q_{DGMin(DG,k,t)} \times X_{DG(DG,k,t)} \le Q_{DG(DG,k,t)} \le Q_{DGMax(DG,k,t)} \times X_{DG(DG,k,t)} \\
&\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; k = 5 \\
&Q_{DGMax(DG,k,t)} = P_{DGMax(DG,k,t)} \times F_{power(DG,t)} \\
&\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; k = 5
\end{aligned} \tag{3.46}$$

Equations (3.47) and (3.48) refer to the Direct Load Control (DLC) demand response capacities, namely the reduction – *DR_A* – curtailment – *DR_B* – programs, respectively. The reduction program (*DR_A*) corresponds to a decrease in the consumption and the curtailment program (*DR_B*) corresponds to the curtailment of the whole consumption of a determined load *l*. For the RD service constraints (3.47) and (3.48) are true whenever the maximum limit of each Type of DR is equal to 0. This happens to be considered DR of type DLC, which lacks the flexibility to participate in the RD service.

$$P_{DR\_A(l,k,t)} \le P_{DR\_AMax(l,k,t)} \qquad (3.47)$$
$$\forall t \in \{1,...,T\}; \forall l \in \{1,...,N_L\}; \forall k \in \{2,3,4,5\}$$

$$P_{DR\_B(l,k,t)} = P_{DR\_BMax(l,k,t)} \times X_{DR\_B(l,k,t)} \qquad (3.48)$$
$$\forall t \in \{1,...,T\}; \forall l \in \{1,...,N_L\}; \forall k \in \{2,3,4,5\}$$

The storage technical limits in each period *t* are restricted by several distinct constraints. These constraints are shown from equation (3.49) to equation (3.61) for all services. For services of increased generation (energy, RU, SP and NS) are considered constraints from (3.49) to (3.56). For the energy and RD joint balance are considered constraints from (3.57) to (3.61). Regarding equation (3.49), it refers to the non-simultaneity of the storage charge and discharge energy.

$$X_{(S,t)} + Y_{(S,t)} \le 1 \qquad (3.49)$$
$$\forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}$$

The battery balance (energy, RU, SP and NS) is established in equation (3.50) with the energy remaining from the previous period and the charge/discharge in the period *t* for each storage unit.

$$E_{Stored(S,t)} = E_{Stored(S,t-1)} + \eta_{c(S)} \times \sum_{k=2}^{N_K} P_{Ch(S,k,t)} \times \Delta t - \frac{1}{\eta_{d(S)}} \times \sum_{k=2}^{N_K} P_{Dch(S,k,t)} \times \Delta t \qquad (3.50)$$
$$\forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \Delta t = 1$$

The charge limit for each storage unit considering the battery charge rate is given by equation (3.51).

$$P_{Ch(S,k,t)} \le P_{ChMax(S,k,t)} \times Y_{(S,t)} \qquad (3.51)$$
$$\forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \forall k \in \{1,...,N_K\}$$

Equation (3.52) indicates the storage charge limit considering the battery balance.

$$\eta_{c(S)} \times \sum_{k=2}^{N_K} P_{Ch(S,k,t)} \times \Delta t \le E_{BatCap(S,t)} - E_{Stored(S,t-1)} \qquad (3.52)$$
$$\forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \Delta t = 1$$

The discharge limit for each storage unit considering the battery discharge rate is presented in equation (3.53).

$$P_{Dch(S,k,t)} \le P_{DchMax(S,k,t)} \times X_{(S,t)} \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \forall k \in \{1,...,N_K\} \tag{3.53}$$

Equation (3.54) shows the storage battery discharge limit considering the battery balance.

$$\frac{1}{\eta_{d(S)}} \times \sum_{k=2}^{N_K} P_{Dch(S,k,t)} \times \Delta t \le E_{Stored(S,t-1)} \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \Delta t = 1 \tag{3.54}$$

The maximum battery charge limit for the services of increasing generation is shown in equation (3.55). This equation relates the flexibility of the storage units in the AS of increase generation (RU, SP and NS) can reduce the charge that acquire in the service energy. For this, the sum of the charge storage variable of these ancillary services must not exceed the value of the charge variable scheduled in energy service.

$$\sum_{k=5}^{N_K} P_{Ch(S,k,t)} \ge \sum_{k=2}^{4} P_{Ch(S,k,t)} \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\} \tag{3.55}$$

The maximum battery discharge limit for the services of increasing generation is shown in equation (3.56).

$$\sum_{k=2}^{N_K} P_{Dch(S,k,t)} \le P_{DchMax(S,t)} \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\} \tag{3.56}$$

The battery balance for energy and RD is determined in equation (3.57).

$$E_{Stored\_RD(S,t)} = E_{Stored\_RD(S,t-1)} + \eta_{c(S)} \times \left(\sum_{k=1}^{1} P_{Ch(S,k,t)} + \sum_{k=5}^{5} P_{Ch(S,k,t)} \right) \times \Delta t - \\ \frac{1}{\eta_{d(S)}} \times \left(\sum_{k=1}^{1} P_{Dch(S,k,t)} + \sum_{k=5}^{5} P_{Dch(S,k,t)} \right) P_{Dch(S,k,t)} \times \Delta t \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \Delta t = 1; \forall k \in \{1,5\} \tag{3.57}$$

Equation (3.58) indicates the storage charge limit considering the energy and RD battery balance.

$$\eta_{c(S)} \times \left(\sum_{k=1}^{1} P_{Ch(S,k,t)} + \sum_{k=5}^{5} P_{Ch(S,k,t)} \right) \times \Delta t \le E_{BatCap(S,t)} - E_{Stored\_RD(S,t-1)} \\ \forall t \in \{1,...,T\}; \forall S \in \{1,...,N_S\}; \Delta t = 1 \tag{3.58}$$

Equation (3.59) concerns the storage battery discharge limit considering the energy and RD battery balance.

$$\frac{1}{\eta_{d(S)}} \times \left(\sum_{k=1}^{1} P_{Dch(S,k,t)} + \sum_{k=5}^{5} P_{Dch(S,k,t)} \right) \times \Delta t \le E_{Stored\_RD(S,t-1)} \tag{3.59}$$
$$\forall t \in \{1,\dots,T\}; \forall S \in \{1,\dots,N_S\}; \Delta t = 1$$

The maximum battery charge limit for the energy and RD is shown in equation (3.60).

$$\sum_{k=1}^{1} P_{Ch(S,k,t)} + \sum_{k=5}^{5} P_{Ch(S,k,t)} \le P_{ChMax(S,t)} \tag{3.60}$$
$$\forall t \in \{1,\dots,T\}; \forall S \in \{1,\dots,N_S\}$$

The last constraints on the storage units, concerns to the maximum battery discharge limit for the energy and RD is shown in equation (3.61). This equation relates the flexibility of the storage units in the RD service can reduce the discharge that was scheduled in the service energy. For this, discharge storage variable of RD service must not exceed the value of the discharge variable scheduled in energy service.

$$\sum_{k=5}^{N_K} P_{Dch(S,k,t)} \ge \sum_{k=1}^{1} P_{Dch(S,k,t)} \tag{3.61}$$
$$\forall t \in \{1,\dots,T\}; \forall S \in \{1,\dots,N_S\}$$

Equation (3.62) relates to each AS requirement in a given region *z*, in period *t*. In order to be able to simulate the AS in a network and obtain the corresponding power flow, it is necessary to locate where is the AS requirement bus. Towards the AS requirement be divided by network regions, it was established that each load *l* belonging to a particular region *z*, composes part of the AS requirement of the region *z*. In this way, the sum of each AS requirement of each load *l*, must match the regional requisite set by the SO. Thus, it becomes possible to determine the power flow for each ancillary service.

$$\sum_{l=1}^{N_L^z} P^z_{req\_\text{limit}(l,k,t)} = P_{AS\_req(z,k,t)} \tag{3.62}$$
$$\forall t \in \{1,\dots,T\}; \forall k \in \{1,2,3,4\}; \forall z \in \{1,\dots,N_Z\};$$

Equation (3.63) refers to the minimum amount that each load *l* can consume in each AS, i.e., is the maximum individual requirement of ancillary services in period *t*.

$$P_{req\_\text{limit}(l,k,t)} \le P^{\max}_{req\_\text{limit}(l,k,t)} \tag{3.63}$$
$$\forall t \in \{1,\dots,T\}; \forall l \in \{1,\dots,N_L\}; \forall k \in \{1,2,3,4\}; \forall z \in \{1,\dots,N_Z\};$$

The constraint that concerns the balance of each AS is equation (3.64). For all AS region, the sum of resources relating to external suppliers, DG and DR is sufficient to meet the requirement of all regional ancillary service, in period *t*.

$$\begin{gathered}\sum_{SP=1}^{N_{SP}} P_{SP(SP,k,t)} + \sum_{DG=1}^{N_{DG}} P_{DG(DG,k,t)} + \sum_{l=1}^{N_L} \left(P_{DR\_A(l,k,t)} + P_{DR\_B(l,k,t)} \right) + \\ \sum_{S=1}^{N_S} \left(P_{Dch(S,k,t)} + P_{Ch(S,k,t)} \right) = \sum_{z=1}^{N_Z} P_{AS\_req(z,k,t)} \\ \forall t \in \{1,...,T\}; \forall k \in \{1,2,3,4\}; \forall z \in \{1,...,N_Z\};\end{gathered} \tag{3.64}$$

Through equation (3.65) it is guaranteed that internal resources of a given region must ensure at least a percentage factor of the AS requirement of the region. This rule is ensured by the variable percentage factor. All resources of the region *z* must be able to guarantee at least half of the requirement that region. However, if this is infeasible, the service can be purchased through the relaxation variables with a respective economic penalty.

$$\begin{gathered}\sum_{SP=1}^{N_{SP}^z} P_{SP(SP,k,t)}^z + \sum_{DG=1}^{N_{DG}^z} P_{DG(DG,k,t)}^z + \sum_{l=1}^{N_L^z} \left(P_{DR\_A(l,k,t)}^z + P_{DR\_B(l,k,t)}^z \right) + \\ \sum_{S=1}^{N_S^z} \left(P_{Dch(S,k,t)}^z + P_{Ch(S,k,t)}^z \right) + RLXD_{(z,k,t)} - RLXU_{(z,k,t)} \geq P_{AS\_req(z,k,t)} \times F_{AS\_req(z,k)} \\ \forall t \in \{1,...,T\}; \forall k \in \{2,3,4\}; \forall z \in \{1,...,N_Z\};\end{gathered} \tag{3.65}$$

Typically, the RLXD variable corresponds to the relaxation variable of the problem used by the VPP in order to make the dispatch simulation always feasible. This variable corresponds to a certain amount of power which is provided directly by the VPP, which may be available through bilateral contracts with large power plants. In order to simulate the physical location of that variable it is proposed that this variable comprises the network resources allocated in a region *w* different from the problematic region *z*, since the thermal constraints of the lines allows that. In equation (3.66) the methodology adopted is implemented.

$$\begin{gathered}\sum_{SP=1}^{N_{SP}^w} P_{SP(SP,k,t)}^w + \sum_{DG=1}^{N_{DG}^w} P_{DG(DG,k,t)}^w + \sum_{l=1}^{N_L^w} \left(P_{DR\_A(l,k,t)}^w + P_{DR\_B(l,k,t)}^w \right) + \\ \sum_{S=1}^{N_S^w} \left(P_{Dch(S,k,t)}^w + P_{Ch(S,k,t)}^w \right) \geq RLXD_{(z,k,t)} \\ \forall t \in \{1,...,T\}; \forall k \in \{1,2,3,4\}; \forall w \in \{1,...,N_Z\}; z \neq w\end{gathered} \tag{3.66}$$

Equation (3.67) represents the maximum upward limit of generation of external suppliers and DG units, related to energy and ancillary services.

$$\begin{gathered}\sum_{k=2}^{N_K} P_{SP(SP,k,t)} \leq P_{CAP\_SP(SP,t)} \\ \forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\} \\ \sum_{k=2}^{N_K} P_{DG(DG,k,t)} \leq P_{CAP\_DG(DG,t)} \\ \forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}\end{gathered} \tag{3.67}$$

Considering that the VPP can establish contracts with the owners of the resources and consumers installed in the network, several kinds of contracts are presented in equation (3.68) to equation (3.72).

The minimum generation in the time horizon contract is represented in equation (3.68). This contract concerns the minimum limit of energy (considering energy, RU, SP and NS services) produced by the generator in a 24-hour period, i.e., the contract ensures that the producer, if dispatched, produces at least the minimum limit defined *a priori*.

$$\begin{aligned}
&\sum_{t=1}^{T}\sum_{k=2}^{N_K} P_{SP(SP,k,t)} \geq P_{SPMin(SP)} \\
&\forall SP \in \left\{1,\dots,N_{SP}\right\} \\
&\sum_{t=1}^{T}\sum_{k=1}^{N_K} P_{DG(DG,k,t)} \geq P_{DGMin(DG)} \\
&\forall DG \in \left\{1,\dots,N_{DG}\right\}
\end{aligned} \tag{3.68}$$

The minimum remuneration contract in the time horizon imposes a minimum limit of remuneration for the whole 24 hours, ensuring a minimum remuneration, regardless the energy produced in each hourly period, considering the energy, RU, SP and NS services. This contract is represented by equation (3.69).

$$\begin{aligned}
&\sum_{t=1}^{T}\sum_{k=1}^{N_K} P_{SP(SP,k,t)} \times C_{SP(SP,k,t)} \geq P_{SP\,\mathrm{Rem}(SP)} \\
&\forall SP \in \left\{1,\dots,N_{SP}\right\} \\
&\sum_{t=1}^{T}\sum_{k=1}^{N_K} P_{DG(DG,k,t)} \times C_{DG(DG,k,t)} \geq P_{DG\,\mathrm{Rem}(DG)} \\
&\forall DG \in \left\{1,\dots,N_{DG}\right\}
\end{aligned} \tag{3.69}$$

The variation of generation contract between periods refers to the gradient of generation in each period. This contract sets for each period of one hour a limit for the increase/decrease power generation according to the previous period. This contract considers the energy, RU, SP and NS services and it is represented by equation (3.70).

$$\begin{aligned}
&\left|\sum_{k=2}^{N_K} P_{SP(SP,k,t)} - \sum_{k=2}^{N_K} P_{SP(SP,k,t-1)}\right| \leq P_{SPVar(SP)} \\
&\forall t \in \left\{1,\dots,T\right\};\forall SP \in \left\{1,\dots,N_{SP}\right\} \\
&\left|\sum_{k=2}^{N_K} P_{DG(DG,k,t)} - \sum_{k=2}^{N_K} P_{DG(DG,k,t-1)}\right| \leq P_{DGVar(DG)} \\
&\forall t \in \left\{1,\dots,T\right\};\forall DG \in \left\{1,\dots,N_{DG}\right\}
\end{aligned} \tag{3.70}$$

The contract’s minimum of periods *t* functioning in time horizon T refers to a minimum period of generation during the overall period of 24 hours. Producers with this type of contract are dispatched for a number of consecutive periods; thereby, they can reduce start-up costs. This contract is represented by equation (3.71) and it is considered for energy, RU, SP and NS services.

$$
\begin{aligned}
&\sum_{t=1}^{T} X_{SP(SP,k,t)} \geq X_{SPMin(SP)} \\
&\forall SP \in \{1,\ldots,N_{SP}\}; \forall k \in \{2,3,4,5\} \\
&\sum_{t=1}^{T} X_{DG(DG,k,t)} \geq X_{DGMin(DG)} \\
&\forall DG \in \{1,\ldots,N_{DG}\}; \forall k \in \{2,3,4,5\}
\end{aligned}
\tag{3.71}
$$

The maximum entries in service contract consist in a maximum number of entries in service throughout the 24 hours. This contract is applied to the energy, RU, SP and NS services. In this context, the producer is forced to ensure stability from generation to avoid being excluded from the selection of production for the period established. This contract is represented by equation (3.72).

$$
\begin{aligned}
&if \;\; X_{SP(SP,k,t-1)} = 0 \\
&\sum_{t=1}^{T} \left(X_{SP(SP,k,t)} - X_{SP(SP,k,t-1)} \right) \leq X_{SPMax(SP)} \\
&\forall SP \in \{1,\ldots,N_{SP}\}; \forall k \in \{2,3,4,5\} \\
&f \;\; X_{DG(DG,k,t-1)} = 0 \\
&\sum_{t=1}^{T} \left(X_{DG(DG,k,t)} - X_{DG(DG,k,t-1)} \right) \leq X_{DGMax(DG)} \\
&\forall DG \in \{1,\ldots,N_{DG}\}; \forall k \in \{2,3,4,5\}
\end{aligned}
\tag{3.72}
$$

The constraints presented in equations (3.73) and (3.74) represent the limits of each resource obtained through Bialek factors. At this stage, the limits considered relate to the calculation of sharing that each resource has on the network, considering only the energy dispatch and its network power flow. Through the limits set it is possible to know from the outset that in any energy and AS joint simulation, the network dispatch becomes feasible.

$$
\begin{aligned}
&P_{SP(SP,k,t)} \leq P_{energy\_\lim\_SP(SP,t)} \\
&\forall t \in \{1,\ldots,T\}; \forall SP \in \{1,\ldots,N_{SP}\}; k = 5
\end{aligned}
\tag{3.73}
$$

$$
\begin{aligned}
&P_{DG(DG,k,t)} \leq P_{energy\_\lim\_DG(DG,t)} \\
&\forall t \in \{1,\ldots,T\}; \forall DG \in \{1,\ldots,N_{DG}\}; k = 5
\end{aligned}
\tag{3.74}
$$

Equations (3.75) and (3.76) consider the maximum limits of DG and external suppliers, obtained through Bialek factors. In this case the factors are calculated based on the energy and Regulation Up optimal dispatch, as well as the network power flow to the optimal dispatch. Thus, the energy and the services (RU and SP) joint optimization, the sum of the production of a particular resource for energy and RU must be less than or equal to the threshold obtained through the Bialek factors.

$$\sum_{k=2}^{N_K} P_{SP(SP,k,t)} \leq P_{energy\_RU\_\lim\_SP(SP,t)} \qquad (3.75)$$
$$\forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\}; \forall k \in \{2,5\}$$

$$\sum_{k=2}^{N_K} P_{DG(DG,k,t)} \leq P_{energy\_RU\_\lim\_DG(DG,t)} \qquad (3.76)$$
$$\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; \forall k \in \{2,5\}$$

The maximum limits for each resource unit which restricts the generation related to services of energy, RU and SP are present in equations (3.77) and (3.78). Based on the dispatch of energy, RU and SP services, the methodology described in the problem in the introduction section, allows simulating the energy and all ancillary services joint market, knowing that constraints between (3.73) and (3.78) limit each resource in order to obtain an dispatch with the features and not to violate the physical network constraints, i.e., not causing network congestion. Therefore, by optimizing the solution becomes perfectly feasible.

$$\sum_{k=2}^{N_K} P_{SP(SP,k,t)} \leq P_{energy\_RU\_Spinning\_\lim\_SP(SP,t)} \qquad (3.77)$$
$$\forall t \in \{1,...,T\}; \forall SP \in \{1,...,N_{SP}\}; \forall k \in \{2,3,5\}$$

$$\sum_{k=2}^{N_K} P_{DG(DG,k,t)} \leq P_{energy\_RU\_Spinning\_\lim\_DG(DG,t)} \qquad (3.78)$$
$$\forall t \in \{1,...,T\}; \forall DG \in \{1,...,N_{DG}\}; \forall k \in \{2,3,5\}$$

3.7. Conclusions

Throughout the evolution of the electric market in a liberalized environment, the modeling of markets has varied according to the characteristics inherent in the structure of power systems in the region in which the market are included.

The models presented in this thesis, and more specifically in this section, address the simulation of energy and ancillary services joint market.

Through the models studied it is possible to understand the operation of real markets, as the models based on information inherent in several real market models.

The energy and AS joint market simulation is a model that can match the highlight the economic efficiency, as explained in this section. In this context, several real markets use this methodology to obtain the lowest possible cost in the management of energy resources.

The concept of AS procurement by network regions is new in the perspective of the MASCEM markets simulation. Thus, the third model is an added value in the continuous development of this simulation tool.

Certain real markets use a simulation model of ancillary services market by regions, wherein the ISO divides the network into several regions. Thus, the regional AS are dispatched according to regional requirements. However, not always the existing resources in a given region are sufficient to meet the required demand, which implies the use of generators outside the region and interties lines between regions in order to cope with the demand required. These scenarios are used for critical cases of congestion emphasized in the system over the experience of operation of the SO, resulting in different market prices between regions.

The joint model with AS bidding regions contemplates the AS simulation by regions and have a variable which allows the SO to ensure that is sufficient generation to provide the region. Moreover, the model guarantees that at least 50% of the output provided by generator units of this region in order ensures good competitive resources, as well as the reliability of the system, relieving the congestion of interties between regions.

The joint market model considering bialek factors presented in this chapter proposes a joint market methodology able to get the best economic solution, ensuring the feasibility of the solution of the all services on the market. That is, the model is based on the methodology of the Bialek topological factors to ensure the feasibility of the dispatch of each service in market trading. Through this model both the ISO and VPP can simulate the market, ensuring from the beginning a viable and feasible solution. Whereas through the market, the conventional methodology performs a provisional dispatch of all services, to further verify the feasibility of the dispatch. Then, the dispatch is adjusted according to the technical features of the network in order to achieve a feasible solution.

In this way, the proposed model has the advantage of ensuring a feasible dispatch for all services traded in the market, presumably faster and without the need for adjustments.

On the continuous increase in the introduction of technologies based on the concept of renewable energy, require a different management of network resources. In this way, the aggregation of resources for a VPP becomes increasingly central to the participation of these resources in the market. In this point of view, resource management can be performed by VPP in order to participate in the market, which focuses on global management of all resources. In this context, the studied models are able to adapt to the required management level either by the VPP or by the ISO.

The joint model applied by VPP focuses on resource management by the VPP, considering the constraints of congestion caused by power flow in the network. The model contemplates an innovative approach able to provide dispatches for all services which does not violate any network technical constraint. Thus, the method always provides feasible and viable dispatches of the energy and ancillary services joint market.

Chapter 4

Case Studies

4. Case Studies

This chapter presents several case studies which illustrate the application of the proposed models (presented in chapter 3) and their respective performance. The presented case studies have been chosen to cover a diversity of situations and involved players, allowing demonstrating the proposed models. The results obtained are presented and discussed for each model. At the end of the chapter some general conclusions are made.

4.1. Introduction

A large diversity of the features of the developed models leads to the need of creating several individual case studies. After this introduction section, which explains the organization of the present chapter, the following sections report the case studies concerning each model presented in chapter 3. Finally, the conclusion section presents the main conclusions of this chapter. Table 4.1 summarizes the scenarios developed for each case study. Each developed scenario has its own characteristics that distinguish it from the other scenarios. In the first column of Table 4.1 are presented several parameters which characterize the models and make distinctions between them.

The Case study 1 – Ancillary Services Market model, refers to a generic AS market simulation model with incorporation of the ancillary services cascading process. This case study was divided into three scenarios. The first scenario considers the AS market simulation in its most simplified way. The second scenario considers the market simulation with the recourse to relaxation variables in order to return a feasible solution. The third scenario considers a comparison between the market simulation of AS with the cascading process and the first scenario developed in order to verify the benefits of the AS cascade process.

The Case study 2 – Energy and AS Joint Market model is based on energy and AS joint market simulation. This case study is composed of two scenarios and a subsection which performs a comparison of both scenarios. The first scenario shows the simulation results of the separated market, in which simulates the energy dispatch separately from the AS dispatch. The second scenario shows the simultaneous simulation of the joint market. A comparison of the two scenarios described above is presented in the last subsection of the case study.

The Case study 3 – AS bidding regions considers the joint market simulation with the bids for ancillary services to be performed by network regions. In this case study, the proposed method is compared with a reference method. This case study is divided into three scenarios. The first scenario considers the joint market simulation in which the power flow resulting for energy service and AS is in the same direction. On the other hand, the second scenario considers the market simulation in which the power flow resulting for energy service and AS flows in opposite directions. The third scenario considers the market simulation with AS cascade process, showing the advantages of this methodology.

Table 4.1 – Case studies characterization.

Characteristics	Model				
	Ancillary Service Market (Case Study 1)	Energy and AS joint market (Case Study 2)	Joint market considering AS bidding regions (Case Study 3)	Joint market considering Bialek Coefficients (Case Study 4)	Joint Market in DNO/VPP operation (Case Study 5)
Market model	AS market	Joint Market	Joint Market	Joint market	Joint Market
Bids	Asymmetric Market	Symmetric Market	Symmetric Market	Symmetric Market	VPP/players contracts
AS cascading process	Yes	Yes	Yes	No	No
Network operation	No	No	Transmission Network with 4 buses considering AC OPF	Transmission Network with 7 buses considering AC OPF	Distribution Network with 33 buses considering AC OPF with Bialek topological factors
Resource management goal	Minimization of ISO operation costs	Market Clearing Price	Market Clearing Price	Market Clearing Price	Minimization of VPP operation costs
AS bidding regions	No	No	AS bids and requirement by two regions of the network	No	AS bids and procurement by four regions of the network
Relaxation variables	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by ISO through bilateral contracts	Ensured by the energy resources of other regions, including external suppliers
Complex Contracts	No	No	No	No	Five types of complex contracts between players and VPP

The Case study 4 – Bialek coefficients considers the joint market using the innovative methodology for solving network congestion. The methodology is based on the Bialek topological factors. The case study is divided into two scenarios. The first scenario presents the results of market simulation without consideration of the methodology of solving the network congestion. The second scenario considers the use of Bialek topological factors together with the joint market simulation. The results of this scenario are compared with the results of the first scenario. In this way, there is the great advantage of use the developed methodology, which always ensures a feasible solution.

The Case study 5 – Joint Market model applied by VPP considers the joint market simulation applied regarding a distribution network operation. Therefore, the operation is controlled by a VPP which manages the energy resources available in the distributed network. In this case study it is applied the developed methodology of the energy and AS joint market simulation which considers the contribution of all services in the network congestion. The developed methodology based on the Bialek topological factors is evidenced in all scenarios in this case study. Thus, the case study is divided into four distinct scenarios. The first scenario consists in the joint market simulation in the scope of a VPP management with application of the developed methodology to ensure viable and feasible solutions. The second scenario is based on the first scenario with the introduction of bids of distributed energy resources be made for network regions (the network was divided into four distinct regions). The third scenario is based on the second scenario in which adds the introduction of DR and relaxation variables in the ancillary services for the network regions. The fourth scenario considers all the inherent characteristics of third scenario with the inclusion of storage units in the ancillary services provision for each network region. The fifth and final scenario maintains the ideology of the previous scenarios with inclusion of complex contracts between players and VPP. These contracts were associated with DG units for the energy service.

4.2. Case study 1 – Ancillary Services Market model

This case study refers to the model developed in section 3.2. After a brief introduction to the considered scenarios with the corresponding input data, the results are presented and some conclusions are made.

Three scenarios compose the case study. The first scenario corresponds to the base scenario of the case study and refers to the market simulation. The usefulness of the relaxation variables is proven in the second scenario, in which the ISO has an obligation to contract other resources through bilateral contracts, ensuring the feasibility of ancillary services dispatch. An ancillary services market simulation with the inclusion of the AS cascade process is presented in the last scenario. Moreover, this scenario also provides a comparison between the AS market simulation with and without AS cascade process.

4.2.1. Outline

The ancillary services model described in section 3.2 considers simultaneous optimization of AS market. In order to simulate the developed model, a set of input data relevant to the type of problem was used.

In this case study, three scenarios are considered in order to observe carefully the results from the proposed methodology.

Therefore, the input data for each scenario are available in the Annex A, tables A1, A2 and A3, and they include essential features for the simulation. These features include the following aspects:

- Bids that each player performs in the market
- AS requirements imposed by the System Operator (SO)

The input data for the first scenario consists of real data available at the CAISO web site [CAISO-2007b].

4.2.2. Results

The results of this case study are based on the referred scenarios and approaches. The first scenario is the baseline scenario of the case study, which besides being analyzed individually, is compared with another scenario in order to know the benefits of the implemented methodology.

4.2.2.1. Scenario 1 – Baseline case

AS cascading is important in order to make the market more competitive, and achieve lower overall cost in contracting power required for the AS dispatch.

Table 4.2 shows the results of the AS dispatch, to the simplest methodology of the AS market simulation.

Regarding to the RD dispatch, the Regulation Down requirement is about 150 MW, from which 111 MW are dispatched by “Bid 5” and the remaining 39 MW are supplied by “Bid 8”. “Bid 8” has a bid price of 4.8 m.u./MW, corresponding to the market clearing price for this service. Although “Bid 4” contains a bid price of 4.0 m.u./MW, the generation minimum limit of this bid is 60 MW. Thus, the “Bid 4” is not dispatched for not fitting the requirement of 39 MW, resulting that a bid with a higher price to be dispatched.

Each of the AS dispatches is related to the market clearing price. This market clearing price is used to calculate the final cost of the market. Each player is remunerated at the market clearing price of each ancillary service.

Table 4.2 – Ancillary services dispatch in scenario 1 of AS model.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	0	5.0	0	10.5	0	10.0	0
2	0	8.0	70	4.5	0	9.2	0	11.0	70
3	0	8.0	0	5.2	0	8.5	0	10.2	0
4	0	4.0	50	5.0	65	8.3	0	10.6	115
5	111	3.5	0	6.3	0	8.9	59	9.0	59
6	0	9.0	0	6.0	0	8.8	0	11.0	0
7	0	7.0	0	7.5	0	9.3	0	10.5	0
8	39	4.8	0	6.5	0	8.6	0	10.4	0
9	0	9.0	0	5.5	0	8.3	0	10.3	0
10	0	10.0	80	4.0	85	8.0	91	9.0	256
Contracted Service (MW)	150		200		150		150		650
Service Requirement (MW)	150		200		150		150		650
Market Clearing Price (m.u./MWh)	4.8		5.0		8.3		9.0		Total (m.u.)
Total Cost (m.u.)	720		1000		1245		1350		4315

Section 4.2.2.3 shows a comparison between scenarios in which it is evidenced the differences between the method with or without AS cascading.

4.2.2.2. Scenario 2 – Relaxation variables

This scenario demonstrates the use of certain variables directed to the relaxation of the dispatch problem when there are special negative events for market stability, in which the forecast capability of these events is poor.

The variables RLXD and RLXU are penalties to the optimization problem for not meeting the AS requirements imposed by the SO. Therefore, the RLXD penalty is applied when the minimum power requirement of an increase generation AS is higher than the sum of maximum power offer by all agents in AS market, i.e., when there is a lack of power to achieve the requirement. In turn, the RLXU penalty is applied when the maximum power requirement of increased generation AS is less than the minimum power of the agent with lower minimum limit of power, i.e., when there is the limit of minimum power of the most lower agent is higher than the maximum AS requirement.

The penalty for each variable has a very high price. For this case study it was established for both variables a penalty of 100 m.u./MW.

The results of the AS simulation considering the use of the relaxation variables are presented in Table 4.3. In this table, it is possible to see the use of RLXD variable by NS service, as well as the contribution of the RLXU variable to the SP dispatch.

Table 4.3 – AS dispatch considering relaxation variables.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	0	15.0	0	5.0	30	7.0	30
2	0	8.0	0	10.0	0	9.0	25	4.0	25
3	0	8.0	0	8.2	0	8.5	30	6.0	30
4	0	4.0	76	5.0	0	7.2	36	4.6	112
5	100	3.5	0	7.0	0	4.0	15	9.0	15
6	0	9.0	0	14.6	55	8.0	19	11.0	74
7	0	7.0	0	8.5	0	7.3	20	10.5	20
8	0	4.8	0	10.6	0	6.6	62	4.0	62
9	0	9.0	39	6.5	0	4.3	35	5.3	74
10	0	10.0	85	4.0	0	9.0	60	5.0	145
Contracted Service (MW)	100		200		55		332		687
RLXD	-		0	100.0	0	100.0	68	100.0	68
RLXU	-		0	100.0	5	100.0	0	100.0	5
Service Requirement (MW)	100		200		50		400		750
Market Clearing Price (m.u./MWh)	3.5		6.5		8.0		11.0		Total (m.u.)
Total Cost (m.u.)	350		1300		400		4400		6450
Cost penalty for players (m.u.)	0		0		500		6800		7300

The power of these penalties is contracted by the SO to special agents, with special contracts for this kind of emergency service.

When penalties are applied, they are not included in the cost of each service to be hired by the SO, i.e., not increasing even more the market clearing price. These penalties are applied to all agents who participate in the service. In several real markets, these penalties costs are accounted for each AS, in which the SO share the cost by the number of agents participating in that service [CAISO-2009].

4.2.2.3. Scenario 3 – Ancillary Services Cascade process

This scenario shows the results of simultaneous optimization of all AS. The simulation model provides the possibility of AS cascading when it is economically more efficient, which implies that a high quality reserve can replace a lower quality one.

In this context, the present subsection compares the scenario presented in section 4.2.2.1 (Scenario 1) related to the scenario shown in Table 4.4 (Scenario 3) of this present section.

In this way, it is clear the use of AS cascade shown in Table 4.4. Through Table 4.4, one can verify that the RU service hired more power than the necessary to meet their needs. This happened as it was triggered the AS substitution through the slack variables. This implies that players who offered their bids in the RU service, have partially satisfied the SP service and fully satisfied the NS service, thus making the AS joint dispatch more economical for the SO. Therefore, to meet their own needs and those of other services, the RU service (SP and NS), resulted in a higher market clearing price for the RU service, than if it had just met their own needs. However, as the bids for SP service and especially for NS service are clearly more expensive, the increase in the market price of the RU service reward makes the system more economically advantageous, regarding the market price that would be charged on NS service if there was no possibility of AS cascade.

Table 4.4 – Ancillary services dispatch considering AS cascade mechanism.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	80	5.0	0	10.5	0	10.0	80
2	0	8.0	85	4.5	0	9.2	0	11.0	85
3	0	8.0	80	5.2	0	8.5	0	10.2	80
4	0	4.0	70	5.0	50	8.3	0	10.6	120
5	111	3.5	0	6.3	0	8.9	0	9.0	0
6	0	9.0	0	6.0	0	8.8	0	11.0	0
7	0	7.0	0	7.5	0	9.3	0	10.5	0
8	39	4.8	0	6.5	0	8.6	0	10.4	0
9	0	9.0	0	5.5	0	8.3	0	10.3	0
10	0	10.0	85	4.0	50	8.0	0	9.0	135
Contracted Service (MW)	150		400		100		0		650
AS Cascading (Slacks)	-		RU to SP 50 5.2 RU to NS 150 5.2		SP to NS 0 8.3 -		-		-
Service Used (MW)	150		200		150		150		650
Market Clearing Price (m.u./MWh)	4.8		5.2		8.3		0.0		Total (m.u.)
Total Cost (m.u.)	720		2080		830		0		3630

The only difference regarding to input data of both scenarios available in Annex A refers to the maximum and minimum requirements for each service, which for the third scenario, these requirements are not equal to the ones presented in the first scenario. With this, there is leeway for the slacks to be used. The results in Table 4.4 show the AS dispatch with clearances resulting in a total cost of approximately 3630 m.u., while the total cost of the AS dispatches without slacks is around 4315 monetary units, as shown in Table 4.5 to compare the scenarios.

As seen in Table 4.5 the information of dispatch and market clearing prices was obtained for each AS and each simulated scenario. Comparing the two scenarios it is noticeable the difference between the total cost of both scenarios. This comparison validates the formulation implemented, taking into account that the AS cascade process can obtain a lower final cost, which meets the main goal to SO for ancillary services, that is to guarantee AS quality at the lowest possible cost.

Table 4.5 – AS dispatch comparison related to scenarios 1 and 3 of AS model.

Market Dispatch	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total	
	Cascade	No Cascade	Cascade	No Cascade	Cascade	No Cascade	Cascade	No Cascade	Cascade	No Cascade
Contracted Service (MW)	150	150	400	200	100	150	0	150	650	650
Market Clearing Price (m.u./MWh)	4.8	4.8	5.2	5.0	8.3	8.3	0.0	9.0	-	
Total Cost (m.u.)	720	720	2080	1000	830	1245	0	1350	**3630**	**4315**

From the results obtained it can be concluded that the model considers the AS substitution, which enables a more economical global AS dispatch, without affecting the reliability of power systems.

4.2.3. Results analysis

In this case study, the simultaneous simulation model of AS market was applied. The main goal of the problem is to minimize costs for the SO. The optimization was performed in GAMS using the MINLP model. In order to know the characteristics and abilities of the model, three scenarios able to express the advantages and disadvantages were developed.

In the first scenario shows the simulation model in a simple way, which lies in a AS simulation, considering only the players involved in these service.

In the second scenario, importance was given to the use of relaxation variables of the problem. These variables guarantee that the AS requirement is satisfied and related to a penalty, regardless the ability of the players who participate in the service.

The third and final scenario shows the AS simultaneous optimization model considering the advantage of using the AS cascade process outlined in implemented model. Also in the section, on the last scenario, it is established a comparison between the results obtained in the first scenario and the last scenario. In this way, one can verify the difference between the possible variations of the model, in which it is clear that considering the AS substitution results in a more economic optimization for the SO.

4.3. Case study 2 – Energy and AS Joint Market model

This subsection presents a case study which illustrates the implementation of the proposed methodology described in section 3.3, in order to perform the energy and AS joint market model. This case study was published in [Soares-2011] and it has been implemented in a multi-agent electricity market simulator (MASCEM) with the objective of providing the simulator with greater flexibility on electricity markets simulation. The main objective of this model is the minimization of costs of joint market for the SO. This subsection includes an outline of the problem, as well as the input data necessary for the simulation model. The results are reported together with some conclusions related to the problem.

4.3.1. Outline

An energy and ancillary services joint market model is implemented in this case study, which is based on the model presented in section 3.3. In order to simulate the developed model a set of input data necessary for the operation of the simulation program has been used.

In this case study are tested two scenarios for the model developed in order to properly understand the main issue to solve the problem.

Annex B provides Table B.1 which contains the input data for solving the problem. These input data include the power and AS seller bids for a set of 10 players based on real offers proposed in CAISO, the buying bids for a set of 10 players, and the values of the required power reserve for each service. Table B.1 also presents the minimum and maximum capacity requirement for each service, constant forecast losses, rigid demand contracted with ISO and energy prices.

4.3.2. Results

This subsection presents the results of this case study. Two scenarios were drafted to give an overview of the possibilities to solve the individual energy and ancillary services market, as well as the joint market. The third subsection shows the comparison between the two scenarios mentioned above.

In this context, the first scenario is based on the separate market simulation for energy and ancillary services. The second scenario concerns the joint market simulation. Finally, the last subsection presents a comparison between the two scenarios presented and draws some conclusions on the advantages and disadvantages of using the joint market simulation model.

4.3.2.1. Scenario 1 – Energy and AS markets (Not-joint)

The scenario presented in this section concerns the separate optimization of the energy and ancillary services market. In this way, the results are the ones of a sequential process simulation. This process is given by the following steps:

- Optimization of the energy market
- Determination of available power
- Optimization of the AS market

The first step results in the simulation of the energy market based on the initial input data from Table B.1 in Annex B. Table 4.6 presents the result of the energy dispatch and power purchase bids dispatched in the market. Besides the energy market ensures the load variable related to power purchase bids, it should ensure the supply of rigid demand and the forecast losses in the system, regardless of the market price.

In this way, the rigid demand and forecasts losses correspond to the regulated supply which arises in the highest part of the demand curve using the price cap of the market. In order to include the rigid demand and the forecast losses in the simulation, the optimization algorithm assigns a very high price for these parcels on the demand curve in order to ensure that these parcels are provided in a market environment.

Table 4.6 – Energy dispatch in scenario 1 of energy and AS joint model.

Bids	Sellers		Buyers	
	Quantity (MW)	Price (m.u./MWh)	Quantity (MW)	Price (m.u./MWh)
1	430	2.1	300	7.0
2	350	3.6	0	5.0
3	480	5.2	0	4.1
4	450	5.8	300	7.7
5	67	6.3	350	8.8
6	270	3.5	350	9.9
7	299	2.8	0	4.5
8	0	9.2	0	3.9
9	345	4.5	300	7.5
10	369	3.9	0	5.5
Rigid Demand	-	-	1300	-
Forecasts losses	-	-	160	-

Figure 4.1 illustrates the energy dispatch with all the considerations listed above.

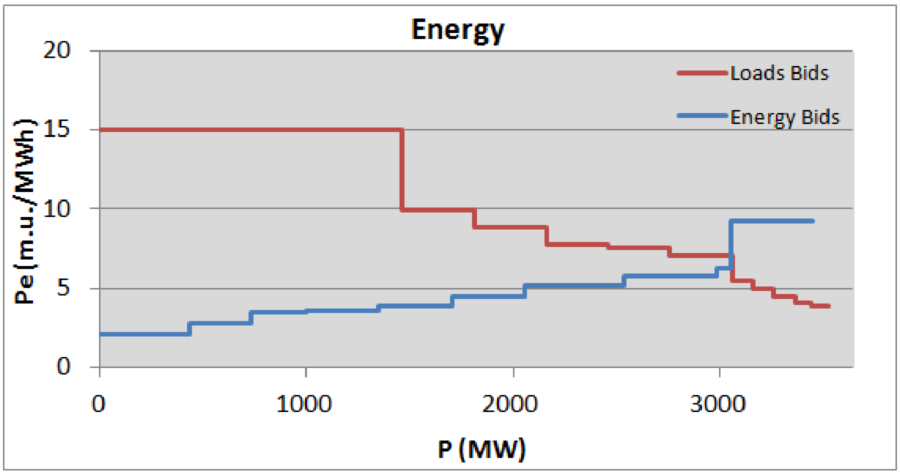

Figure 4.1 – Energy market clearing price in scenario 1 of energy and AS joint model.

The second step of the simulation concerns the determination of the maximum capacity of generation bids for the participants in the AS market. In order to obtain the maximum capacity of generation bids, it is necessary to calculate the difference between the power used by each bid in the energy market and the limit of "Max Power" set out in Table B.1 from Annex B. Therefore, Table 4.7 includes the values used for each bid in the AS market. The bids which participated with its full available capacity in the energy dispatch present values of "Residual Max Power" different from 0, as seen in Table 4.7. This is due to the threshold established in each bid for the energy which does not correspond exactly to their maximum capacity generation, as seen in Table B.1.

Table 4.7 – Residual maximum power.

Bid	Residual Max Power (MW)
1	20
2	50
3	20
4	30
5	233
6	10
7	21
8	405
9	55
10	31

The third step results in the AS market simulation considering the limits determined in the previous step. This way, results of the AS market considering a simple process and the inclusion of cascading process are presented.

Figure 4.2 illustrates the dispatch of each ancillary service according to the energy required by the system operator for these services. In this case, only the participant bids in each service can provide this service.

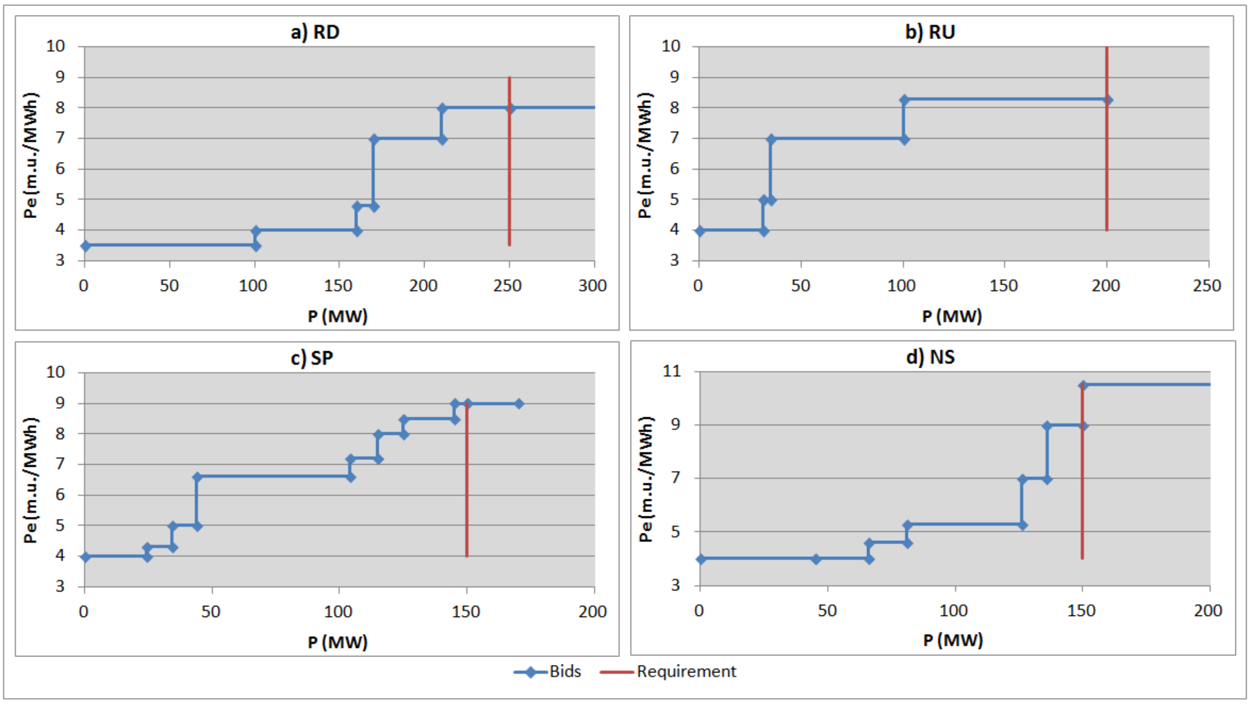

Figure 4.2 – Ancillary services dispatch in scenario 1 of energy and AS joint model.

According to the ancillary services simultaneous market model with AS cascade process, it is possible to reduce the operation costs for the ISO. Therefore, Figure 4.3 illustrates the AS dispatch when there is the ancillary services cascading.

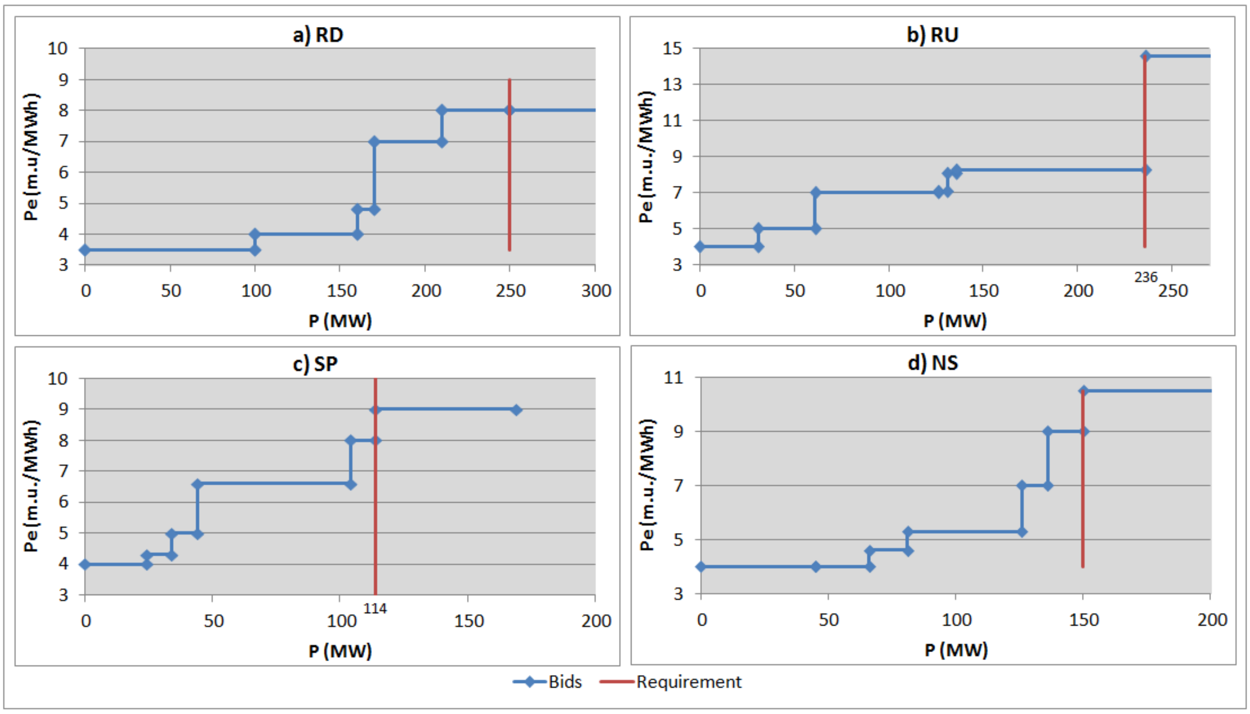

Figure 4.3 – Ancillary services dispatch with cascading mechanism in scenario 1 of energy and AS joint model.

By comparing the results presented in Figure 4.2 and Figure 4.3, one can concluded that the market clearing price of Spinning Reserve decreases from 9.0 m.u./MWh to 8.0 m.u./MWh corresponding to a power decrease from 150 MW to 114 MW. In compensation, the Regulation Up provides more 36 MW (236 MW) with a market clearing price equal to 8.3 m.u./MWh, in order to cascade energy to SP, thus reducing the overall costs of AS. The cascading allows a better optimization of AS, combining the three services (RU, SP and NS). In Table B.2 and Table B.3 are the exact values of the bids which participate in the AS and the market clearing price for each ancillary service. The variables of the cascading process, usually called slacks, and its respective price can be seen in Table B.3.

4.3.2.2. Scenario 2 – Energy and AS joint market

The implemented energy and AS joint market model is presented in this scenario.

The joint market simulation considers the simultaneous dispatch of energy and Ancillary Services. From the perspective of the ISO, this model allows a better optimization of the power capacity of each agent participating in the markets. This limit does not affect the Regulation Down dispatch, since this service is a component for the frequency control when there is excess of generation.

In this context, Figure 4.4 presents the market clearing price of the energy market. It is considered that the market has to provide a rigid demand as well as the load bids. After satisfying this mandatory demand, the market price is determined, in accordance with the selling and buying bids. The rigid demand and forecasts losses are represented in the figure by the initial offer at high price (15 m.u./MWh) in the demand curve, knowing what impact these parameters have in obtaining the market clearing price.

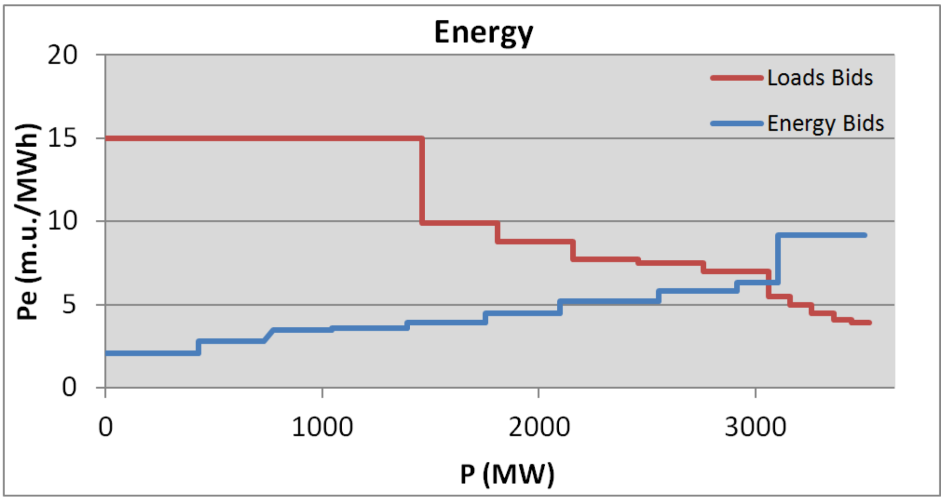

Figure 4.4 – Energy market clearing price in scenario 2 of energy and AS joint model.

The simultaneous dispatch of the joint market is presented in Table 4.8. This table comprises information on the dispatch of each service with its respective market clearing price, as well as the transfer power in AS cascading process.

Table 4.8 – Energy and AS joint market dispatch.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Energy		Loads		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	0	15.0	10	5.0	0	7.0	430	2.1	300	7.0	440
2	40	8.0	5	8.1	0	9.0	45	4.0	350	3.6	0	5.0	400
3	0	8.0	44	7.1	0	8.5	0	6.0	456	5.2	0	4.1	500
4	60	4.0	50	5.0	30	7.2	41	4.6	359	5.8	300	7.7	480
5	100	3.5	65	7.0	24	4.0	0	9.0	191	6.3	350	8.8	280
6	0	9.0	0	14.6	10	8.0	0	11.0	270	3.5	350	9.9	280
7	40	7.0	0	7.2	0	7.3	21	4.0	299	2.8	0	4.5	320
8	10	4.8	0	8.3	60	6.6	0	10.5	0	9.2	0	3.9	60
9	0	9.0	2	6.5	10	4.3	43	5.3	345	4.5	300	7.5	400
10	0	10.0	40	4.0	0	9.0	0	5.0	360	3.9	0	5.5	400
Contracted Service (MW)	250		206		144		150		3060		1600		2210
Slacks	-		RU to SP 6 8.1 RU to NS 0 8.1		SP to NS 0 8.0 -		-		-		-		-
Market Clearing Price (m.u./MW)	8.0		8.1		8.0		5.3		6.3		6.3		Total (m.u.)
Total Cost (m.u.)	2000		1668.6		1152		795		19278		10080		14813.6

Furthermore, it is possible to identify individual costs that each service represents for the system operator, as well as the overall cost of the market. The total cost of the market operation is determined based on the sum of the costs of energy and ancillary services dispatches. In order to better understand the simulated market, Figure 4.5 graphically shows the ancillary services dispatch. The market clearing price is obtained through the intersection of supply curve and the AS requirement.

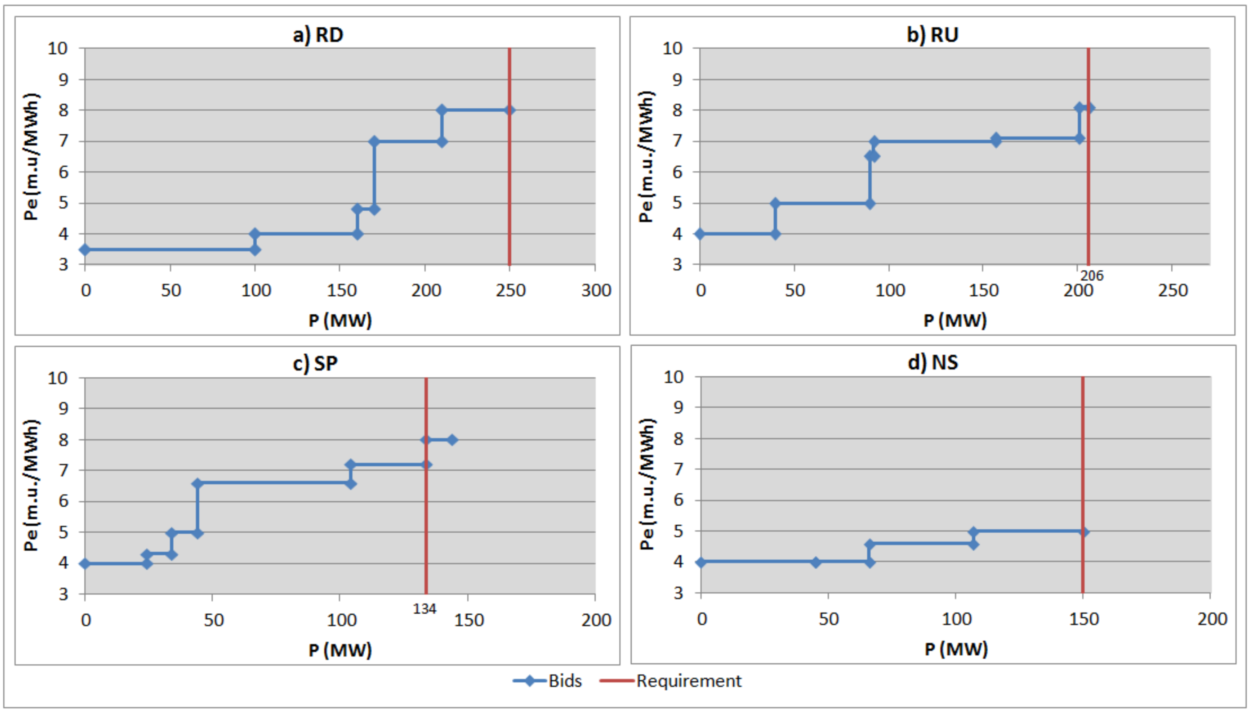

Figure 4.5 – Ancillary services dispatch in scenario 2 of energy and AS joint model.

4.3.2.3. Comparison of scenarios

This section introduces a comparison of the scenarios described in the previous sections (4.3.2.1 and 4.3.2.2) for the energy and AS joint market model.

Table 4.9 – Costs and market clearing price comparison related to scenario 1 and 2 of energy and AS joint model.

Market Price (m.u./MWh)					
Service	AS Market		Energy	Join	Balance
	No slack	Slack	Market	Market	
Regulation Down	8.0	8.0	-	8.0	0.0
Regulation Up	8.3	8.3	-	8.1	0.2
Spinning Reserve	9.0	8.0	-	8.0	0.0
Non-Spinning Reserve	9.0	9.0	-	5.3	3.7
Energy	-	-	6.3	6.3	0.0
Total Cost (m.u.)	6360.0	6220.8 15418.8	9198.0	14813.6	605.2

In this way, Table 4.9 shows the market clearing price for each service for both scenarios, as well as the market total cost involved in the scenarios. In this context, it is presented an overview on the differences between the scenarios in order to highlight the economic performance of each scenario.

The total cost for the AS market in the separated market model without considering the AS cascade process is 6360.0 (m.u.). The value corresponds to the quantities presented in section 4.3.2.1, Figure 4.2. The values 6220.8 m.u. (AS cascading process) and 9198.0 m.u. (energy dispatch) are obtained in the same way, but using the values which correspond to AS cascade process presented in Figure 4.3 (a Table B.3 of the Annex B) and to the energy market presented in Table 4.6.

According to these results the AS costs are less expensive when it is activated the AS cascade process. In this point of view, the total cost of the separate market which considers the AS cascade process is smaller when compared to the more simplistic separate market. In this market it was obtained an overall cost of 15418.8 (m.u.). This process was carried out in order to be compared with the joint market scenario. It can be concluded that the joint market ensures a better solution than the individual optimization of energy and ancillary services markets. This case study presents a difference of 605.2 m.u. This difference arises from the comparison of costs between the joint market (14813.6 m.u.) and the sum of the costs of separated energy and AS market (15418.8 m.u.). This is due to the market clearing price obtained in the joint market regarding the Regulation Up and Non-Spinning services that are lower than the one obtained by the separate market simulation.

4.3.3. Results analysis

An energy and ancillary services joint market model is the methodological basis of the problem addressed in this case study. Thus, the problem lies in the energy and AS joint market simulation, with the main goal of minimizing the costs involved in the problem to the system operator. The optimization has been performed on GAMS optimization tool using their solvers.

The case study was developed in accordance with the possibility of showing the intrinsic features of the model developed, and the case study is divided into three distinct parts.

Firstly, a scenario capable of identifying step by step the characteristics in each market simulation was developed. This means that a simulation was developed for the individual energy market and the AS market.

The second part of the case study refers to the energy and AS joint market simulation, in which it is consider the true essence of the proposed model.

The third part comprises a comparison of previous scenarios in order to highlight the advantages that the use of joint market may bring to the operation mode of markets.

The main advantage of the joint market is the ability of the combination of several bids for energy and AS. Thus it is possible to combine the contribution that each bid has on all services dispatches (except the Regulation Down service), according to the "Max Power" capacity of the bid. The solutions presented by this market model may not be technically possible when considering technical constraints of the network. In this way, the system operator must verify that the solution presented meets the technical validation of network constraints. In case the dispatch provided by the model violates the technical constraints, it is subject to readjustments in order to become a feasible solution.

4.4. Case study 3 – AS bidding regions

A case study is proposed in this section to implement the market model exposed in subsection 3.4. The presented case study is based on the energy and ancillary services joint market considering different bidding regions. The case study performs a comparison between the model described in section 3.4 and the model published by [Wu-2004]. The developed model considers an Alternate Current (AC) Optimal Power Flow (OPF) while the reference model is based on a Direct Current (DC) OPF. By using an AC OPF, it is possible to determine the active and reactive power flow on the network, as well as the losses associated to the system. In this way, the market simulation presents the results of the dispatches closer to the reality, which is an advantage of the proposed method relative to the reference method.

The main goal of the model is to minimize the costs of the joint market dispatch, in which the AS requirements imposed by the ISO are defined by network regions. A brief introduction to the problem and the required input data, as well as the simulation results and the respective conclusions are presented in this section.

4.4.1. Outline

This case study illustrates the implementation of the energy and AS joint market model considering different bidding regions. To simulate this case study it is necessary a set of input data capable of demonstrating the comparison between the proposed method and the reference method.

Therefore, the case study is compared with [Wu-2004], which uses a 4-node network with four branches. Based on this network, [Wu-2004] uses an DC OPF in this methodology to determine network power flow. To obtain a more realistic simulation, an AC OPF, is proposed. In this way, it was considered the network shown in Figure 4.6 with a few changes.

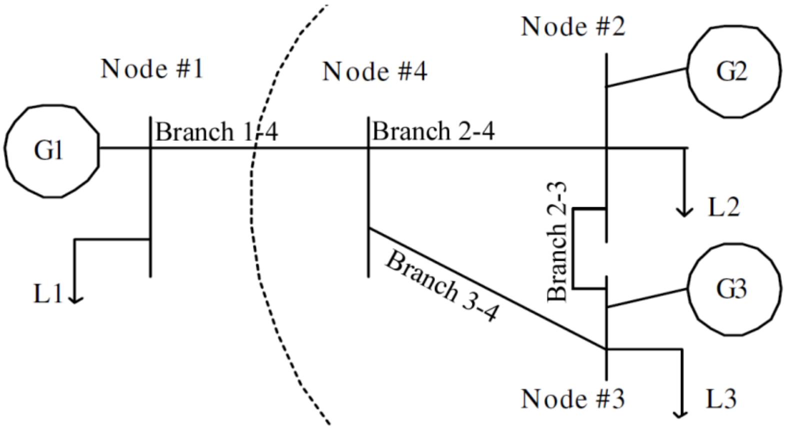

Figure 4.6 – 4-buses network with four branches [Wu-2004].

The features included in the network are presented in Table 4.10, and correspond to the resistance and inductance characteristics of the network. To include the network characteristics in this case study it has been used the lines characteristics of Institute of Electrical and Electronics Engineers (IEEE) 14 Bus test case [Group-1973].

Table 4.10 – 4-buses network features.

Bus *i*	Bus *j*	Resistance (p.u.)	Inductance (p.u.)	Line Capacity (MVA)
1	4	0.05695	0.17388	40
2	3	0.05403	0.22304	50
2	4	0.04699	0.19797	50
3	4	0.05811	0.17632	50

Table 4.11 presents the bids related to the energy and the AS of the reference paper, without considering the requirements of the AS and their contingencies which give rise to the AS regions identified in [Wu-2004].

In this way, the simulation of the proposed methodology not considering the AS requirements and contingencies is performed, in order to obtain the energy optimal dispatch. Three scenarios were simulated involving the energy dispatch according to the exposed in the reference method. The execution of several operation contexts was performed so that the developed methodology obtains solutions according to several situations that can arise during the network operation. In this way, four operation context containing different parameters at the generation unit contribution of generation were simulated. The first operation context summarizes the base case which assumes that all generators may be in service. The second operation context considers that the generation unit G1 is out of service, while the third operation context considers that the generation unit G2 is out of service. The last operation context considers that the branch 1-4 is disabled. These operation contexts were performed for Scenario 1.

Based on [Wu-2004], the loads L1 (export), L2, L3 have fixed schedules of 20 MW, 30 MW and 100 MW, respectively.

Table 4.11 shows the bids made by each generation unit for all services. The bids information provided by Table 4.11 are a fundamental part of the basis of the scenarios studied in this case study.

Table 4.11 – Energy and AS bids.

Methodology	Reference [Wu-2004]			Proposed methodology		
Resources	G1	G2	G3	G1	G2	G3
Energy Bid price (m.u./MWh)	10	30	45	10	30	45
RD Bid price (m.u./MW)	-	-	-	10	15	20
RU Bid price (m.u./MW)	-	-	-	10	20	30
SP Bid price (m.u./MW)	5	15	35	5	15	35
NS Bid price (m.u./MW)	-	-	-	15	10	40
Total Bid Capacity (MW)	100	200	300	100	200	300

The AS requirements considered in the control area are listed below. RD requirement was established in 50 MW. The RU requirement has a range of values between the minimum and maximum of 50 MW to 100 MW. Following the same principles of the RU cascade, the SP requirement has a range from 100 MW to 150 MW, while the NS requirement has a fixed value of 50 MW.

In order to establish the regions and their requirements, it was assumed the same constraints established in [Wu-2004] for each AS, which implies that the imports between regions may not exceed 50% of each AS requirement of this region. Thus, in each AS requirement, Region 1 may not provide more than 50% of AS requirements of Region 2. The total production of all regions should ensure at least the supply of each AS requirement. Based on [Wu-2004] the resources of the Region 3 must ensure at least 85% of the AS requirement.

In this way, the contingencies discussed above gave rise to the following AS regions: Region 1 contains Node 1, Region 2 contains all network nodes, Region 3 contains Node 3.

For SP reserve:

- Region 1: $G1 \leq 50$
- Region 2: $G1 + G2 + G3 \geq 100$
- Region 3: $G3 \geq 85$

For other AS:

- Region 1: $G1 \leq 25$
- Region 2: $G1 + G2 + G3 \geq 50$
- Region 3: $G3 \geq 42.5$

The results are divided into three scenarios. The first scenario considers the joint market simulation with the Ancillary Services power flow in the same direction as the energy power flow predetermined in the case study.

In the second scenario certain changes are imposed in the input data, in order to obtain a power flow simulation concerning the energy and AS are in opposite directions.

The third and final scenario discusses the ability of AS cascade by the proposed model, since the reference model does not incorporate this versatility in its methodology.

4.4.2. Results

4.4.2.1. Scenario 1 – Energy and AS in the same direction

An energy and AS joint simulation approach with the same direction in the power flow is carefully explained in this scenario.

This case considers all the energy and AS bids shown in Table 4.11, based on [Wu-2004]. In this way, by analyzing the data from Table 4.11 it is possible to see that G1 is the cheapest producer in several services.

When comparing the dispatches between the proposed methodology and the reference method, it seems that a discrepancy between the two methods is mainly due to the consideration of lines losses and reactive power, as can been seen in Table 4.12. Considering the reactive power in the line implies that the energy that flows in line contains an active and reactive share. Thus, the capacity of active power flowing in the line is smaller compared to the reference method.

Regarding the comparison of the operation contexts, it is verified in last operation context that in the reference method generator G1 do not participate in the dispatch, in which it is considered the disabling of branch 1-4. Once the branch is disabled, generation unit G1 can supply the load allocated to its bus, which does not appear in reference method. Thus, this scenario cause some mismatch between the dispatches, with the dispatch related to the reference method does not provide all the required loads.

Table 4.12 – Energy dispatch by operation context in scenario 1 of joint market model considering AS bidding regions.

Energy Schedule (MWh)	Reference [Wu-2004]			Proposed methodology		
Base Case	60.0	85.0	5.0	58.7	79.9	11.9
G1 outage	0.0	115.0	35.0	0.0	109.7	40.8
G2 outage	60.0	0.0	90.0	57.8	0.0	92.7
Branch1-4 outage	0.0	105.0	25.0	20.0	99.7	30.8

Table 4.13 shows the results of the base case simulation, with the comparison of the results obtained based on reference [Wu-2004]. Thus, as can see the energy and AS dispatch results are identical. The generator G1 uses the full capacity of branch 1-4 to dispatch the energy; however, it can provide the RD service, as this service does not enter directly into the competition with energy and others AS, because it is a decrease service production and not the opposite.

The LMP obtained in the methodology is rather different to the reference method. In the developed methodology the determination of the LMP considers not only the active power, but also the system losses and congestion in the network. In this way, these characteristics are the causes of deviations of the comparison between LMP.

Table 4.13 – Base case results of energy and AS in same direction.

Methodology	Reference [Wu-2004]			Proposed methodology		
Resources	G1	G2	G3	G1	G2	G3
Energy Schedule (MWh)	60.0	85.0	5.0	58.7	79.9	11.4
RD Bid Award (MW)	-	-	-	7.5	0.0	42.5
RU Bid Award (MW)	-	-	-	0.0	7.5	42.5
SP Bid Award (MW)	0.0	15.0	85.0	0.0	15.0	85.0
NS Bid Award (MW)	-	-	-	0.0	7.5	42.5
LMP (m.u./MWh)	10.0	30.0	45.0	10.0	32.9	41.4

The contingencies G1 outage and G2 outage provide different energy and AS dispatches, as shown in Table 4.14. In G1 outage generators G2 and G3 are required to provide the load in node 1. In this way, there is the high LMP of 39.3 m.u./MWh at node 1, as evidenced when G1 is not available, the node 1 LMP increases about 20 m.u./MWh. In what concerns the contingency G2 outage, one can verify a similar trend to the previous LMP in node 2. This is due to the fact that the G3 is more expensive to provide energy and AS.

Table 4.14 – G1 and G2 outage results.

Methodology	Proposed methodology (G1 outage)			Proposed methodology (G2 outage)		
Resources	G1	G2	G3	G1	G2	G3
Energy Schedule (MWh)	0.0	109.7	40.3	57.8	0.0	92.2
RD Bid Award (MW)	0.0	7.5	42.5	7.5	0.0	42.5
RU Bid Award (MW)	0.0	7.5	42.5	0.0	0.0	50.0
SP Bid Award (MW)	0.0	15	85	0.0	0.0	100.0
NS Bid Award (MW)	0.0	7.5	42.5	0.0	0.0	50.0
LMP (m.u./MWh)	39.3	35.0	43.6	10.0	40.7	40.8

Branch 1-4 outage contingency implies that the network is divided into two distinct operation areas. The G1 only has to ensure that L1 is provided. Thus, node 1 LMP corresponds to the G1 energy bid price, as shown in Table 4.15.

In the context of island operation, generators G2 and G3 compete between themselves to provide the loads and meet the AS requirements.

Table 4.15 – Branch 1-4 outage results.

Methodology	Proposed methodology		
Resources – Branch 1-4 outage	G1	G2	G3
Energy Schedule (MWh)	20.0	99.7	30.3
RD Bid Award (MW)	0.0	0.0	50.0
RU Bid Award (MW)	0.0	7.5	42.5
SP Bid Award (MW)	0.0	15	85
NS Bid Award (MW)	0.0	7.5	42.5
LMP (m.u./MWh)	10.0	35.0	43.6

The network regions applied to ancillary services helps ensuring the system reliability in the desired control area. The stipulated control area comprises buses 2, 3 and 4. All AS requirements are designed to the control area.

With the constraint related to region 1, it is intended to limit the import of power from Bus 1 to the control area. With the region 3 the internal generation unit of this region (the generator G3) has a strong role in contributing to ancillary services. Since this generation unit is, in general, the most expensive unit, one way to ensure the stability of the power flow in the control area is through the ancillary services. By defining the AS procurement by regions, it is possible to establish rules for supplying with resources for each region.

With Table 4.13 one can verify that the market simulation establishes the AS dispatch for generator G3, to the minimum as possible generation required by the constraint of region 3. This is because the network is stable at that point. In the case where generator G2 is outage and affect the energy dispatch (Table 4.14), the ancillary services which increase generation are fully guaranteed by generator G3, thus ensuring the stability of the control area.

Operation costs and the execution time for each contingency scenario are shown in Figure 4.7. It seems that the scenario in which G1 is outage, the scenario is the most expensive in the overall energy and AS operation costs, since generator G1 has the energy and three of the four AS most inexpensive, regarding the competing generators.

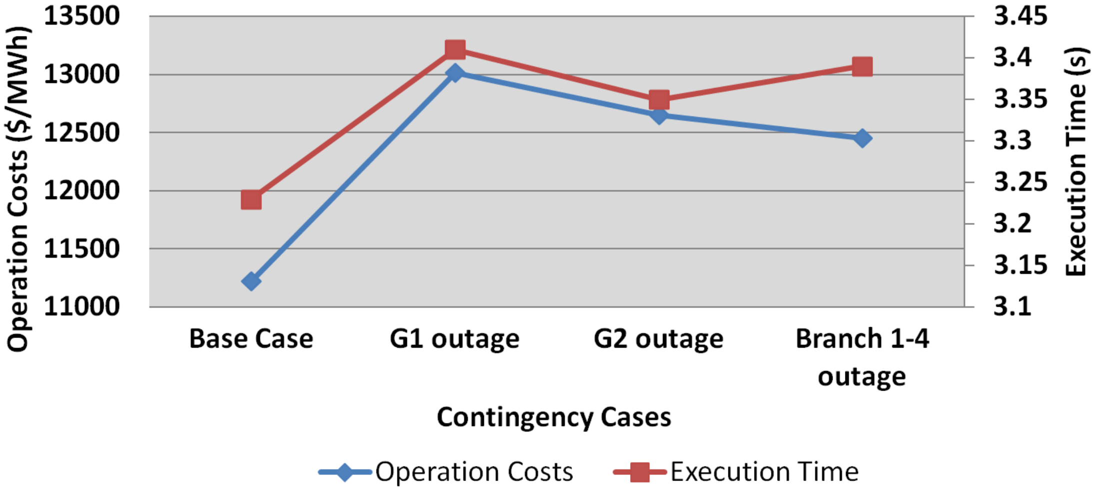

Figure 4.7 – Operation costs and execution time in the contingency cases.

4.4.2.2. Scenario 2 – Energy and AS in opposite direction

This scenario considers specific changes in order to condition power flow in opposite directions of energy and AS.

In this context, in order to simulate the previously described situation, it becomes necessary to change some assumptions used in the previous scenario. Therefore, the changes are related to the generators bids and the capacity of the network branches:

- The energy bid of G1 is increased to 80 m.u./MWh;
- The capacity of Branch 1-4 is reduced to 10 MVA in both directions.

The simulation results based on changes described above are shown in Table 4.16. The evidenced results show that the G1 energy bid is too expensive to participate in energy dispatch; however, this bid is forced to supply in energy service due to the fact that the maximum export capacity of Bus 4 to the Bus 1 is limited to 10 MVA (branch 1-4). So, G1 must generate at least 10 MW in energy service, since the load on Bus 1, has 20 MW of energy requirement. On the other hand, the generator G1 can generate up to 20 MW on ancillary services, in order not to exceed the limit set in branch 1-4 of 10 MVA. In the Spinning reserve service, generation unit G1 is the cheapest resource supplying 15 MW, since the constraint of Region 3 implies the participation of generation unit G3 at least 85% of the service requirement, in this case corresponding to 85 MW.

Table 4.16 – Base case results of energy and AS in opposite direction.

Methodology	Reference [Wu-2004]			Proposed methodology		
Resources	G1	G2	G3	G1	G2	G3
Energy Schedule (MWh)	10.0	110.0	30.0	10.7	104.3	35.0
RD Bid Award (MW)	-	-	-	7.5	0.0	42.5
RU Bid Award (MW)	-	-	-	0.0	7.5	42.5
SP Bid Award (MW)	10.0	5.0	85.0	15.0	0.0	85.0
NS Bid Award (MW)	-	-	-	0.0	7.5	42.5
LMP (m.u./MWh)	80.0	30.0	45.0	73.8	35.0	43.6

Figure 4.8 shows the power flow of the network at the end of the market simulation getting the dispatch of all services (energy and ancillary services).

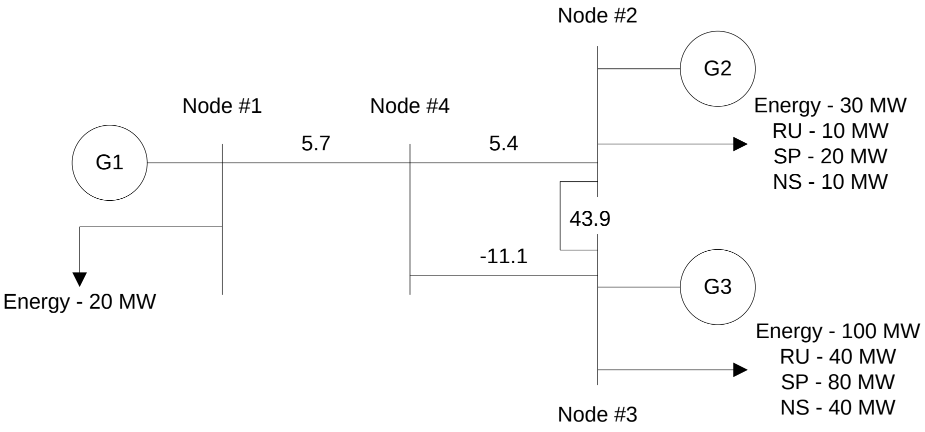

Figure 4.8 – Power flow of energy and AS dispatch.

The constraint of region 3 ensures that the internal generation units of the region must provide at least 85% of the AS requirements of control area. Therefore, it seems that the export of generator G1 is limited not only by the branch, but also by the ancillary services bidding regions. Otherwise, generator G1 would have a major contribution in the ancillary services dispatch.

4.4.2.3. Scenario 3 – Energy and AS cascade optimization

This scenario deals with the possibility of AS cascade. AS cascade has as the basic principle the possibility of using RU as SP and/or NS after the RU requirement is met. In the same direction, the SP can be used as NS after the SP requirement is met.

In order to simulate the AS cascade dispatch, it is necessary to change the AS bids price. In this way, it was amended the following condition:

- The RU bid of G3 is decreased to 5 m.u./MWh.

Considering the simulation based on the previous scenario simulation data (section 4.4.2.2), it is easy to understand that the RU service can partially replace the SP and NS requirements. In this case, the RU service provides 5 MW to the SP service and 10 MW to NS service, as shown in Table 4.17. This can happen when the high quality service dispatch is less expensive than a lower quality service dispatch. In practice, this situation is very unusual, since usually a high quality reserve is more expensive than a lower quality reserve.

Table 4.17 – AS cascade results.

Methodology	Proposed methodology with AS Cascade mechanism		
Resources	G1	G2	G3
Energy Schedule (MWh)	10.7	104.3	35.0
RD Bid Award (MW)	7.5	0.0	42.5
RU Bid Award (MW)	0.0	0.0	62.5
SP Bid Award (MW)	10.0	0.0	85.0
NS Bid Award (MW)	0.0	0.0	42.5
LMP (m.u./MWh)	73.8	35.0	43.6

4.4.3. Results analysis

This case study was developed regarding the possibility of showing the intrinsic characteristics of the model developed in comparison with the case study of the reference method published in [Wu-2004]. The case study is divided into three different scenarios.

The first scenario reports the comparison of the proposed methodology with the reference methodology, considering the energy and AS power flow in the same direction. In this scenario the AS dispatch is simulated according to certain situations that may occur from the energy operation context. Some generation units as well as the network branches can be outage, affecting not only the energy dispatch, but also the ancillary services. In this way, the joint dispatch considering “G1 outage” is the scenario more expensive which imposes an addition of about 14% in the operation costs, comparing to the base case. With the generation unit “G1 outage”, the LMP of bus 1 is considerably higher (about 75%) than the base case.

The second scenario of this case study compares two methods with regard to the energy and AS power flow in opposite directions. This scenario is not so common, because the AS is usually supplied by generators of large capacity on the network. However, it can happen on certain contexts of the power systems operation. In this way, one can evaluate the responsiveness of the model for such cases. The results show that in some branches the power flow related to the AS runs in the opposite direction to the energy, resulting in the mathematical annulment of power flows in the branch. It can be concluded that generator G2 located in the bus 2 exports 10 MW through branches 2-4 and 1-4 to the bus 1, while in the spinning reserve dispatch, the generation unit G1 exports 10 MW through branch 1-4 to bus 4. This confirms an opposite flow between energy and AS. Thus it is shown that the method allows the energy and ancillary services dispatch with opposite power flow.

The third and last scenario refers to the simulation model considering the possibility of the AS cascade process being actuated, thus reducing operation costs for the ISO. Through the cascade process, the operation costs in this scenario decreased approximately 2% regarding the base scenario. It can be concluded that this methodology may show an advantage in the economic efficiency of the market.

All methods have their advantages and disadvantages inherent to the particular form of solving the problem. In comparison to reference methods, the main advantages of the proposed methodology are: considering the AC power flow on the network; the inclusion of all AS (namely, RD, RU, SP and NS) procurement by the ISO in competitive market environment, as well as the possibility of AS cascade substitution optimization, if there is more economically advantages. Another important advantage identified is the differences in the formulation to solve the problem between both methods, in which the proposed model is presented in section 3.4. Therefore, the scenarios presented highlight the differences between the two methods at the level of LMPs at each network node. It is somewhat significant, implying that operating costs are lower in those particular cases in the reference method. However, the reference methodology considers only the energy and network contingencies in the LMP calculation, while the proposed method in the LMP calculation considers the energy, losses and network contingencies. Thus, through the LMP calculation of the proposed methodology has a clearly closer approximation to the reality of the power systems operation.

The main disadvantage identified is mainly due to the simulation time to solve the problem. Although the execution time of the reference method is not available, it should be faster, in order to the reference methodology be less complex and also implemented in linear programming. In this context, the proposed methodology may have some difficulties to be fast enough for the real-time market with a huge number of input data.

Regarding the ancillary services bids being made through the regions of the network, it is verified that this methodology does not necessarily imply a prejudice in the ISO operation costs. In a normal operation context (the energy base case dispatch), the use of AS increases the ISO operation costs. However, in critical operation context of contingencies presented when "G2 outage" or even "Branch 1-4 outage", it is clear that bidding by region and the respective constraints associated to each region makes the system more robust and prepared to deal with inconveniences cases of generation outage, which may be little predictable. In this way, the ancillary service market simulation considering different bidding regions prevent the system to have much import energy, reinforcing the benefit of the internal generation units in the network operation to ensure high levels of system reliability.

Briefly, the presented case study is based on the reference method and was compared with the proposed methodology, demonstrating how the proposed methodology is effective to solve the envisaged problem, and showing its applicability to real markets.

4.5. Case study 4 – Bialek coefficients

This section presents a case study regarding the model proposed in section 3.5. It considers the simulation of a joint market with an AC OPF and a new methodology based on Bialek topological factors for solving of network constraints and congestion caused by all AS scheduling.

4.5.1. Outline

The case study is divided into two scenarios. One of the scenarios considers the join market simulation using an AC OPF for simulating the characteristics of the network.

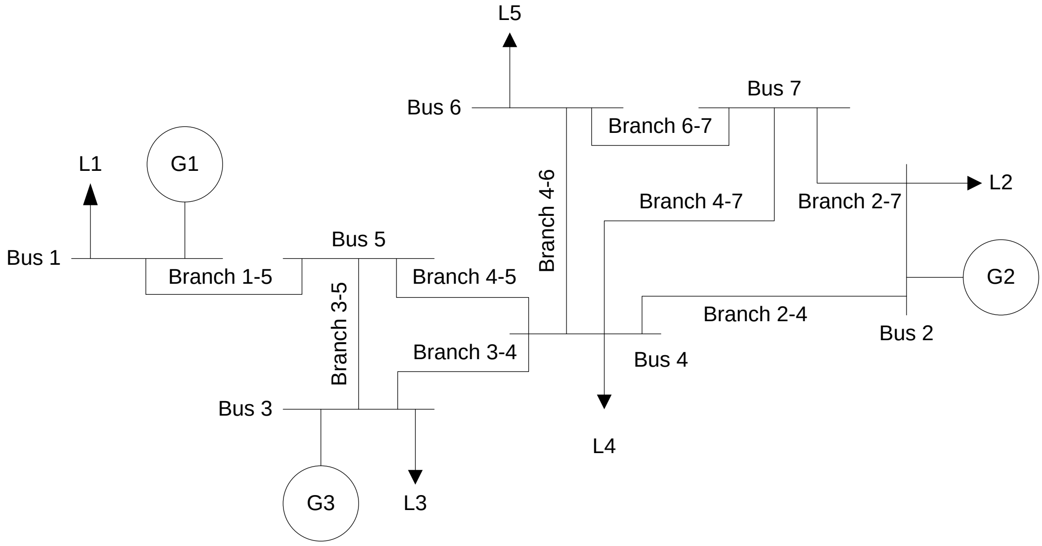

Figure 4.9 – 7-buses network.

The second scenario is based on the previous scenario with the inclusion of the methodology developed using the method of Bialek topological factors. The scenarios presented in this chapter use a transmission network with 7 buses illustrated in Figure 4.9.

The characteristics related to resistance, inductance and thermal limit of each branch used in the network are presented in Table 4.18.

Table 4.18 – 7-buses features.

Bus *i*	Bus *j*	Resistance (p.u.)	Inductance (p.u.)	Line Capacity (MVA)
1	5	0.05695	0.17388	40
2	4	0.05403	0.22304	50
2	7	0.04699	0.19797	50
3	4	0.05530	0.21430	50
3	5	0.05559	0.18837	50
4	5	0.04866	0.20977	20
4	6	0.04999	0.20654	50
4	7	0.05722	0.18656	50
6	7	0.05811	0.17632	50

Table 4.19 shows the characteristics of generators and loads connected on the network, where Qt is the quantity of power and Pe is the bid price.

Table 4.19 – Generators input data.

Resources	Energy		Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Maximum Capacity (MW)
	Qt (MW)	Pe (m.u./MW)	Qt (MW)	Pe (m.u./MW)	Qt (MW)	Pe (m.u./MW)	Qt (MW)	Pe (m.u./MW)	Qt (MW)	Pe (m.u./MW)	
1	100	10	100	10	100	20	100	10	100	15	100
2	200	15	200	15	200	10	200	15	200	20	200
3	300	20	300	20	300	15	300	20	300	10	300

Table 4.20 presents the energy and Ancillary services requirements for each load on the network. The requirements of ancillary services (Regulation Up, Spinning and Non-Spinning Reserve) for Loads 1 and 2 were set to 10 MW, in order to provide situations of opposites power flow caused by the dispatches of all services for increased generation. Thus, it is possible to highlight the main advantages and disadvantages of the models used in each scenario of this case study.

Table 4.20 – Energy and AS requirements.

Loads	Energy Qt (MW)	Regulation Down Qt (MW)	Regulation Up Qt (MW)	Spinning Reserve Qt (MW)	Non-Spinning Reserve Qt (MW)
1	20	2	10	10	10
2	30	3	10	10	10
3	100	10	10	10	10
4	50	5	5	3.5	3.5
5	77	7.7	7.7	5.39	5.39

4.5.2. Results

4.5.2.1. Scenario 1 – Baseline case

This subsection shows the simulation results of the energy and ancillary services joint market using an AC OPF (baseline case).

Table 4.21 shows the results relating to each service dispatch obtained in the market. The solution proposed is only possible if all services are been dispatched at the same time.

In fact, the dispatch of all services has a hierarchy in which the energy service is the first to be dispatched. In this way, one must ensure that the dispatch of energy service is feasible. In the results presented, it seems that energy dispatch alone is not feasible. For the generator G2 was awarded a dispatch of about 149.70 MW; however, the branches which connect Bus 2 (where generator G2 is coupled) to other buses is limited to 50 MVA in each branch. The load coupled to Bus 2 has a consumption of 30 MW. In seems that there is congestion on the branches (149.70-50-50-30=19.70), making the energy dispatch infeasible.

Table 4.21 – Energy and AS dispatch in scenario 1 of joint market model considering Bialek coefficients.

Generator	Energy Qt (MW)	Regulation Down Qt (MW)	Regulation Up Qt (MW)	Spinning Reserve Qt (MW)	Non-Spinning Reserve Qt (MW)
1	41.05	27.7	0	0	0
2	149.70	0	0	0	0
3	86.25	0	42.82	38.89	38.89

In this way, the energy dispatch only becomes feasible when it is considered the power flow resulting from the energy, Regulation Up, Spinning and Non-Spinning dispatches. This happens because the Load related to Bus 2 has a considerable requirement for Regulation Up, Spinning and Non-Spinning services, and the requirements of these services are supplied by the generation unit G3. This implies that for each ancillary service the generation unit G3 causes a opposite power flow regarding the energy dispatch power flow, which decreases mathematically the power flow that flows in branches between Bus 2 and Bus 3. Moreover, with a simultaneous market simulation, the optimization process allows the combination of the services dispatch, so that the simultaneous dispatch of all services does not violate the thermal limits of the branches. However, when analyzing the dispatch independently, it seems that the energy dispatch is unfeasible.

In the context of independent analysis of the energy dispatch, Table 4.22 represents the power flow of energy service imposed on network. Thus, it is possible to verify that the particular energy dispatch is infeasible, since it violates the thermal limits of the branch 2-4 and the branch 2-7.

Table 4.22 – Power flow of energy service and joint market, in scenario 1 of joint market model considering Bialek coefficients.

Bus *i*	Bus *j*	Power flow for energy service		Overall power flow		Line Capacity (MVA)
		Active (MW)	Apparent (MVA)	Active (MW)	Apparent (MVA)	
1	5	21.05	22.42	-8.95	11.51	40
2	4	65.15	65.64	44.20	48.76	50
2	7	54.55	55.18	45.50	48.51	50
3	4	-2.17	6.18	48.30	48.31	50
3	5	-11.58	11.65	28.55	28.88	50
4	5	-9.47	11.83	-19.59	20.00	20
4	6	33.09	34.60	48.58	49.90	50
4	7	-10.68	10.69	1.47	4.05	50
6	7	-43.83	45.43	-46.92	50.00	50

Therefore, one can conclude that the simultaneous dispatch of all services traded in the market may not be feasible in the power systems operation.

4.5.2.2. Scenario 2 – Base case with Bialek factors

The scenario described in this subsection considers the energy and ancillary services joint market simulation according to the methodology developed in section 3.5. Through this method it is possible to ensure the dispatch feasibility for each service, and the results presented in this subsection related to the desired simulation. The simulation is performed according to the hierarchical structure of the services considered in the market.

Table 4.23 shows the simulation results of the joint market which include the innovative methodology. The solution presented reports that each dispatch is feasible.

Through Table 4.23 it is possible to verify that the power flow of the energy dispatch obtained through the developed methodology follows the same direction of power flow from the energy dispatch shown in the previous scenario. However, it seems that through this new methodology, the joint or individual services dispatches are feasible.

Table 4.23 – Energy and AS dispatch in scenario 2 of joint market model considering Bialek coefficients.

Generator	Energy Qt (MW)	Regulation Down Qt (MW)	Regulation Up Qt (MW)	Spinning Reserve Qt (MW)	Non-Spinning Reserve Qt (MW)
1	49.09	27.7	0	0	0
2	129.41	0	10.27	10.14	7.13
3	98.50	0	32.54	28.75	31.76

In this scenario and following the reasoning of the previous observation, generator G2 was awarded a dispatch of 129.41 MW for energy service as it can be seen in Table 4.23. In this way, considering the characteristics of the network, the generator G2 does not cause congestion in the network. Generator G2 obtained an energy dispatch of 129.41 MW, about 30 MW of its generation was used to supply the load L2. This generator contributed approximately 49.81 MW for branch 2-4 with thermal limit of 50 MVA and also approximately 49.60 MW for branch 2-7 with a thermal limit of 50 MVA. Thus, it is clear that the obtained dispatch for energy service is feasible. However, the feasibility of the presented solution is very close to the maximum limit allowed by the network features, as it can be seen in Table 4.24, which presents the values of the power flow resulting from the market simulation. Table 4.24 shows the power flow in network regarding the energy dispatch and to all services, simultaneously. In this way, it seems that in some branches of the network, the power flow has reached the maximum limit of the power allowed to flow on the branch. Branch 4-5 is exploited to its limits due to generator G1 allocated on Bus1, that is a generation unit cheaper for energy service compared to other generators, as well as the thermal limits of the branch that are more restricted than in other branches.

Table 4.24 – Power flow considering Bialek topological factors.

Bus *i*	Bus *j*	Power flow for energy service		Overall power flow		Line Capacity (MVA)
		Active (MW)	Apparent (MVA)	Active (MW)	Apparent (MVA)	
1	5	29.08	30.23	-0.91	3.14	40
2	4	49.81	50.00	48.68	50.00	50
2	7	49.60	50.00	48.27	49.26	50
3	4	9.00	11.85	40.71	41.05	50
3	5	-10.00	10.69	20.84	21.24	50
4	5	-19.07	20.00	-19.91	20.00	20
4	6	35.70	37.59	47.62	48.41	50
4	7	-8.45	9.25	-0.35	1.64	50
6	7	-41.31	42.53	-47.88	49.45	50

4.5.3. Results analysis

This case study was developed in order to demonstrate the advantages of the developed methodology. The case study is divided into two distinct scenarios.

The first scenario describes a joint market simulation based on the use of an AC OPF, in which it is verified the infeasibility of the solutions presented by the method, due to all services considered in the power flow.

The second scenario presents the simulation results of the market based on the developed methodology which considers the use of an AC OPF and the Bialek topological factors, in order to ensure a feasible dispatch for each service on the market. In this way, the sequential dispatch of energy, Regulation Up, Spinning and Non-Spinning reserve are feasible regardless of the hierarchical structure of the services.

The main advantage of the method developed compared to the methodology in the first scenario is the guarantee of obtaining feasible solutions, regardless of the services considered in the market.

The main disadvantages are related to the execution time of the market clearing price process, for which in first scenario there is a execution time of around 3 seconds, while in the second scenario, the execution time of simulation is about 9 seconds. This disadvantage tends to prevail more when increasing the complexity of the problem, when considering more complex constraints in the market simulation.

Another disadvantage concerns to the operation costs. The first scenario has an operational cost of around 7626 (m.u.), while the second scenario involves operation costs of around 8014.75 (m.u.). This implies an increase of 5% in operation costs.

In networks with greater amount of resources, it is assumed that the market clearing price is considerably more preponderant, thus yielding different operation costs which are considerably significant to the ISO.

4.6. Case study 5 – Joint Market model applied by VPP

Based on the model proposed in section 3.6, this section presents a case study illustrating the proposed problem.

The case study presents the results of simulation of an energy and ancillary service joint optimization, in which are implemented the following particular characteristics of the model:

- The use of an AC power flow for energy and ancillary services, considering the Bialek topological factors;
- The division of the network into regions for the AS;
- The introduction of Distributed Energy Resources (DER), namely Distributed Generation (DG) units which contemplates technologies related to wind, photovoltaic, small hydro units, Combined Heat and Power (CHP), Municipal Solid Waste (MSW), Biomass and Fuel Cell, as well as Direct Load Control Demand Response (DR) types (Reduce and Cut) and storage units;
- Complex contracts between the VPP and the owners of generation units.

Besides contemplating a brief introduction of the problem addressed, this section presents all the input data used for the simulation model.

Several scenarios are considered in order to provide the reader with all the characteristics surrounding the problem and its resolution method adopted. At the end of this section important conclusions are drawn, showing the usefulness and feasibility of the developed model.

4.6.1. Outline

In the context of Smart Grid operation, an energy and AS joint market optimization considering different bidding regions and complex contracts are discussed in this case study. In order to obtain representative results of the desired simulation, it was considered the use of input data based on [Faria-2010], with some modifications described throughout this section. These changes were developed in order to better display the impact of the proposed algorithm in the simulation performed. The results are divided into five distinct scenarios.

The first scenario contemplates the energy and AS joint market considering the use of Bialek topological factors, in order to prevent congestion on the network branches.

In second scenario are considered the AS network regions. This implies that players make bids for their region, although they may participate in other regions if they have the availability to do so after the requirement be fulfilled in their region, and that are economically advantageous for the VPP.

The third scenario demonstrates the potential use of DR in regional AS dispatch. Besides the DR this scenario shows the use of a relaxation variable. This variable is associated with a high penalty, which is only activated when there is a lack or excess of generation for AS negotiated in regional market environment. All resources available in network regions may participate in the dispatch of this kind of variable.

The fourth scenario comprises the flexibility of the storage units in the ancillary services delivery. It is considered the possibility of decreasing the power charge or discharge in ancillary services, taking into account the power scheduled in the energy service.

In the fifth and final scenario, complex contracts in negotiations between the players and the VPP for energy service are introduced. The complex contracts covered in this scenario are the minimum limit of remuneration or power generation, as well as the minimum number of consecutive hours in operation among other contracts.

The case studies presented in this chapter use a distribution network with 33-bus that can be found in [Baran-1989, Faria-2010]. Figure 4.10 shows the projection of 33-bus distribution network in 2040 with Distributed Generation (DG) spread over the network [Faria-2010]. In this figure, the solid lines represent the branches that are used, and the dashed lines represent the branches that can be used in a reconfiguration scenario. In Annex C, Table C.1 presents the resistance, inductance and thermal limit of each branch used in this distribution network.

In Figure 4.10 the DG units are represented by different colors, which identify the used generation technology. Additionally, the installed power is indicated. For the year 2040, this network includes 66 DG units (32 photovoltaic, 15 CHP, 8 fuel cell, 5 wind farms, 3 biomass, 2 small hydro and 1 MSW). For the case studies presented in this chapter, it is considered that the VPP has the obligation of buying all the generation power from photovoltaic units. The input data relating to the characteristics of the DG and the prices applied for the energy service are provided in Annex C, Table C.2. In this context, Annex C also provides data for each AS, decomposing into two tables. Table C.3 and Table C.4 contains illustrative prices for each ancillary service.

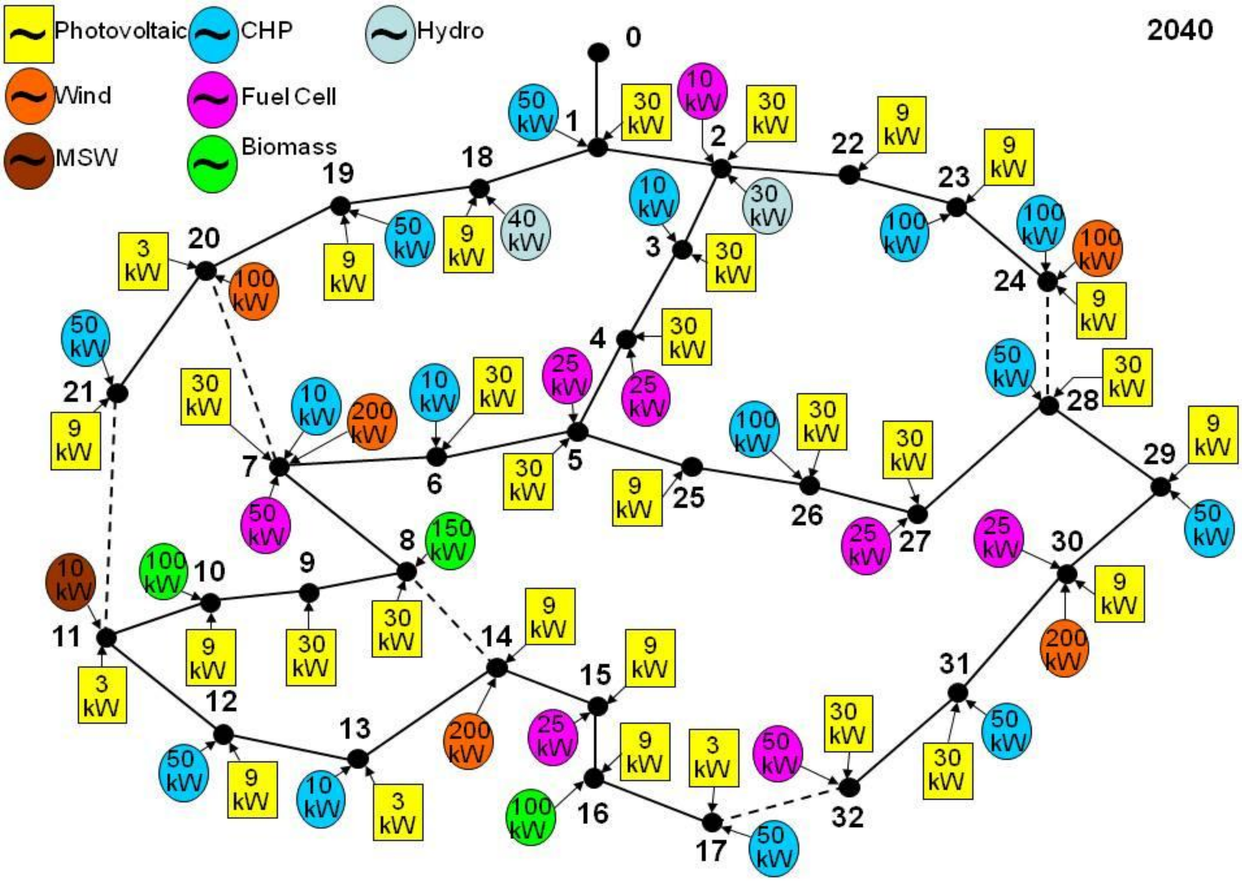

Figure 4.10 – 33-buses distribution network configuration in 2040 scenario [Faria-2010].

All input data presented below are related to the first scenario. The maximum limit that each resource can provide to the ancillary services corresponds to a percentage of the maximum limit of resource production. The values considered in the base case study are presented in Table 4.25. Thus, for Regulation down service each resource has the capacity to reduce power until the limit of maximum power reduction, which is equivalent to 5% of the maximum limit of overall selling bid, for Regulation Up each resource is limited to produce up to 5% of the maximum limit of global production, while for the other ancillary services (SP and NS) each resource is limited to produce up to 10% of the maximum limit of global production.

Table 4.25 – Energy and AS upper limits in scenario 1 of joint market model applied by VPP.

Services	Percentage of maximum overall production (%)
Energy	100
Regulation Down	5
Regulation Up	5
Spinning Reserve	10
Non-Spinning Reserve	10

Additionally, the network contains 32 loads distributed by each bus. Each of the 32 loads contains specific requirements. Likewise, each load is related to Direct Load Control (DLC) DR, which contains the Reduce and Cut types. The Reduce type considers the possibility of gradual decrease in the consumption of the load, while the Cut type involves a load curtailment with a fixed power. The DR is associated with energy service for all scenarios, although in scenarios three to five the DR is considered for the ancillary services. The input data related to the DR are in Annex C, Table C.5.

Regarding to the AS bids related to the DR, these bids are assigned based on the characteristics of DR energy bids. For both types of DR (Reduce and Cut), the amount of power of the bids available for RD and RU services corresponds to 10 % of the total required demand. While for SP and NS services corresponds to 7% of the total required load. The price for each type of DR and for each AS corresponds to 80% of the price of DR for energy service, provided in Annex C, in Table C.5.

Besides the features mentioned above, storage units are included in the network. In Annex C, Table C.6 illustrates the characteristics relating to these resources. The characteristics inherent in the storage units consist in battery capacity, charge and discharge power rate, amount of energy stored in batteries in previous state (the amount of initial energy in the batteries) and its charging and discharging prices.

The AS requirements imposed by the VPP are provided in Table 4.26, an element of the case studies presented. These requirements were obtained through the consideration of percentage of energy peak load in each time period. The percentages of initial values considered are established to be in line with the best view of the characteristics of the presented scenarios. The minimum and maximum values of AS requirements shown in the Table 4.26, consider the time horizon of 24 periods.

Table 4.26 – AS requirements in scenario 1 of joint market model applied by VPP.

Ancillary Services	Requirement		
	Minimum (kW)	Maximum (kW)	Peak Load (%)
Regulation Down	139.7	181.1	2.5
Regulation Up	139.7	181.1	2.5
Spinning Reserve	279.4	362.3	5.0
Non-Spinning Reserve	279.4	362.3	5.0

The second scenario aims to simulate the energy and ancillary services joint market considering different AS bidding regions.

In this way, it is described below the implied changes to the input data base in order to be able to obtain simulation results for the proposed scenario. The base distribution network underwent some minor changes. These changes are due to the possibility of considering the AS dispatches for individual network regions and they are described below. As one can see in Figure 4.11, the network is divided into four distinct regions. (Region 1 – red background; Region 2 – blue background; The Region 3 – yellow background; finally, the Region 4 – green background).

In the context of the dispatch by network regions, the VPP should provide AS requirements for each region, in order to be possible to obtain the dispatch for each region. The AS requirements for each region are shown in Table 4.27.

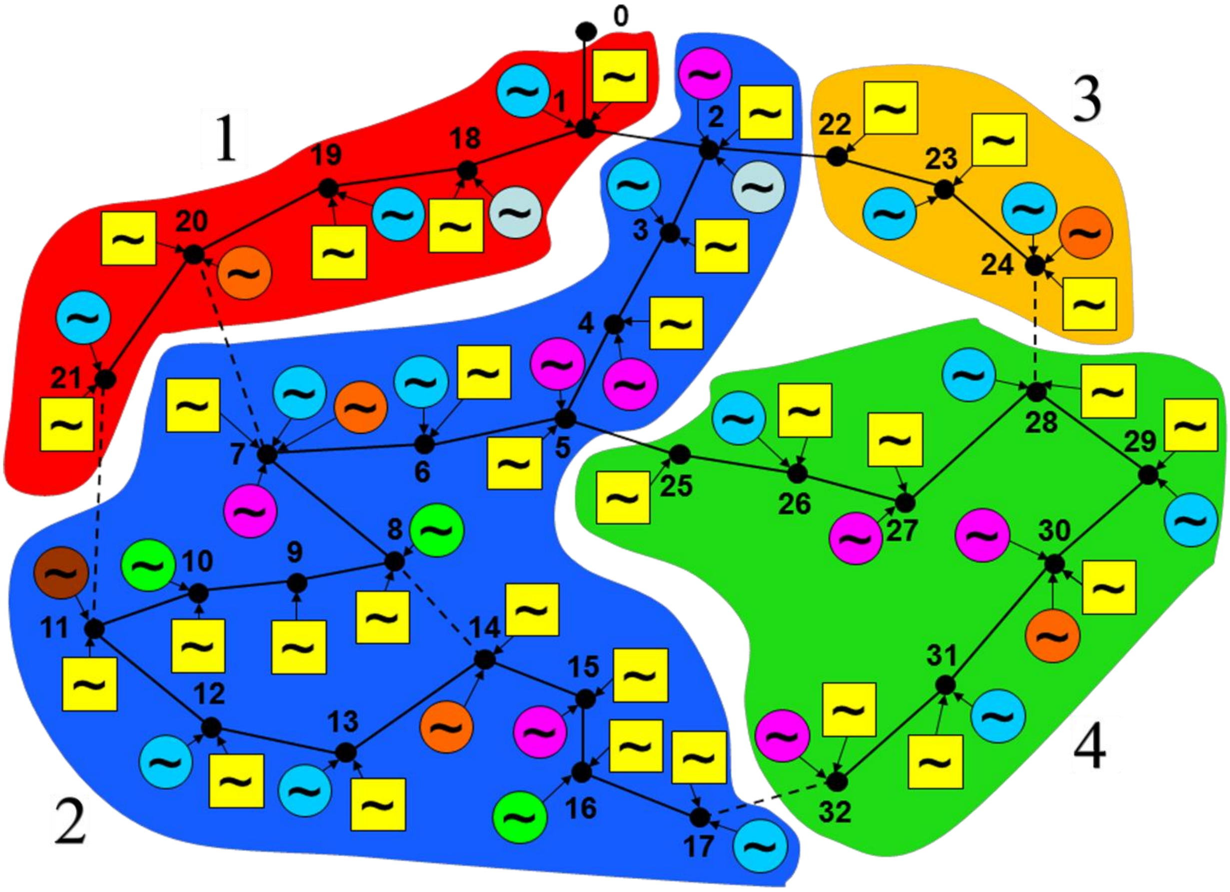

Figure 4.11 – AS regions on the 33-buses distribution network.

However, in AS dispatch to a particular region, other regions can participate in the dispatch, but the participation of other regions is limited to 50% of region requirement.

Table 4.27 – AS requirements by regions, in scenario 2 of joint market model applied by VPP.

Regions	Ancillary Services	Requirement (kW)		
		Minimum	Mean	Maximum
1	Regulation Down	18.186	21.810	24.367
	Regulation Up	18.186	21.810	24.367
	Spinning Reserve	36.371	43.620	48.734
	Non-Spinning Reserve	36.371	43.620	48.734
2	Regulation Down	53.307	62.798	68.992
	Regulation Up	53.307	62.798	68.992
	Spinning Reserve	106.614	125.595	137.985
	Non-Spinning Reserve	106.614	125.595	137.985
3	Regulation Down	35.145	41.588	46.039
	Regulation Up	35.145	41.588	460.39
	Spinning Reserve	70.291	83.177	92.078
	Non-Spinning Reserve	70.291	83.177	92.078
4	Regulation Down	33.051	38.306	41.730
	Regulation Up	33.051	38.306	41.730
	Spinning Reserve	66.102	76.611	83.461
	Non-Spinning Reserve	66.102	76.611	83.461

The maximum limit that each resource (DG and external supplier) can provide for a particular service underwent some changes, being these changes are related to the increase of the maximum limit of generation for the Regulation Up, Spinning and Non-Spinning services. The maximum limit of the overall production doubled, and the limits for each resource of each service are shown in Table 4.28. Thus, this change allows increasing the probability of obtaining feasible solutions.

Table 4.28 – Energy and AS upper limits in scenario 2 of joint market model applied by VPP.

Services	Percentage of maximum overall production (%)
Energy	100
Regulation Down	5
Regulation Up	10
Spinning Reserve	25
Non-Spinning Reserve	15

The third scenario is based on energy and the AS joint market simulation considering the introduction of DR and relaxation variables on ancillary services dispatch, is presented in this section. In order to obtain the desired scenario, one can proceed to some change of the input data regarding the input data of the case study presented in the second scenario.

In this way, one can consider some significant changes on AS requirements by region. Table 4.29 shows the ancillary services requirements for each region imposed by the VPP. By comparing Table 4.29 with Table 4.27 of the previous scenario, there is an addition in the requirements for the RU and SP services in each region. Although it was possible to change the prices of the DR resources in order to become more competitive, it was preferred to make changes in the power requirements. The change of values of power requirements was chosen because the DR contribution has a major impact in the dispatch, and because it is possible to activate the relaxation variables, for lack of sufficient generation to provide the service dispatch in a particular region.

Table 4.29 – AS requirements by region, in scenario 3 of joint market model applied by VPP.

Regions	Ancillary Services	Requirement (kW)		
		Minimum	Mean	Maximum
1	Regulation Down	18.186	21.810	24.367
	Regulation Up	45.465	54.525	60.918
	Spinning Reserve	109.113	130.860	146.202
	Non-Spinning Reserve	36.371	43.620	48.734
2	Regulation Down	53.307	62.798	68.992
	Regulation Up	133.268	156.995	172.480
	Spinning Reserve	319.842	376.785	413.955
	Non-Spinning Reserve	106.614	125.595	137.985
3	Regulation Down	35.145	41.588	46.039
	Regulation Up	87.863	103.970	115.098
	Spinning Reserve	210.873	249.531	276.234
	Non-Spinning Reserve	70.291	83.177	92.078
4	Regulation Down	33.051	38.306	41.730
	Regulation Up	82.628	95.765	104.325
	Spinning Reserve	198.306	229.833	250.383
	Non-Spinning Reserve	66.102	76.611	83.461

The maximum production limits of each resource (DG and external supplier) for each service have been changed. These changes are shown in Table 4.30, which imposes the maximum limit production of each DG and external suppliers for each service, depending on the overall limit of resource production. In this way, the percentage values for each existing service in Table 4.30 correspond to a percentage of the overall value which the resource can provide for a certain service. These values assume that the maximum limit of global production corresponds to the sum of all services which produce energy (energy, Regulation Up, Spinning and Non-Spinning reserve).

Table 4.30 – Energy and AS upper limits, in scenario 3 of joint market model applied by VPP.

Services	Percentage of maximum overall production (%)
Energy	100
Regulation Down	5
Regulation Up	5
Spinning Reserve	5
Non-Spinning Reserve	10

In order to obtain a considerable dispatch of DR for ancillary services, was established for each load the maximum limits for DLC DR types (Reduce and Cut) regarding each ancillary service. Table 4.31 shows the range of values that fall within the DR resources for each service. In this way, the main changes relate to services (RU and NS), in which the capacity of each resource can offer in the market is equivalent to the portion of energy service. Thus, these resources will have greater participation and influence in the dispatch of their respective services. Furthermore, it was established that the Spinning Reserve requirement would be three times higher than the used in the base case. In the same direction, the Regulation Up requirement suffered an increase equivalent to 250% of the values presented in the base scenario mentioned in this case study.

Each value shown in the Table 4.31 refers to the maximum limit that each type of DR can achieve in terms of limits for the DR energy service. Therefore, the dispatch of the DR of type Reduce may involve this resource up to a maximum limit equivalent to the used in the energy service.

Table 4.31 – Demand response types for each service.

DR	Percentage of maximum limit of DR in energy service (%)	
	Reduce	Cut
Regulation Up	100	100
Spinning Reserve	10	10
Non-Spinning Reserve	100	100

The fourth scenario considers an energy and AS joint market simulations with the inclusion of storage units bids in the ancillary services procurement. Beyond these considerations, this scenario comprises all the features developed in previous scenarios. However, several changes were implemented in the input data, as well as the increment of new data necessary to perform this scenario.

Table 4.32 shows the requirement for each ancillary service according to the regions of the network. By comparing this table with Table 4.27, one can verify that the difference between these two AS requirements tables happens for Regulation Down service. For this scenario it was established the change of the RD requirement in order to verify the possibility of contribution of storage resources in this dispatch. In this way, the RD requirement is five times higher than the stipulated in the base case which corresponds to 12.5% of the load power service value.

Table 4.32 – AS requirements by region in scenario 4 of joint market model applied by VPP.

Regions	Ancillary Services	Requirement (kW)		
		Minimum	Mean	Maximum
1	Regulation Down	90.929	109.050	121.836
	Regulation Up	18.186	21.810	24.367
	Spinning Reserve	36.371	43.620	48.734
	Non-Spinning Reserve	36.371	43.620	48.734
2	Regulation Down	266.535	313.988	344.962
	Regulation Up	53.307	62.798	68.992
	Spinning Reserve	106.614	125.595	137.985
	Non-Spinning Reserve	106.614	125.595	137.985
3	Regulation Down	175.727	207.942	230.195
	Regulation Up	35.145	41.588	46.039
	Spinning Reserve	70.291	83.177	92.078
	Non-Spinning Reserve	70.291	83.177	92.078
4	Regulation Down	165.255	191.528	208.652
	Regulation Up	33.051	38.306	41.730
	Spinning Reserve	66.102	76.611	83.461
	Non-Spinning Reserve	66.102	76.611	83.461

The prices of charge and discharge energy from the storage units for AS were based on the power service price. These values are available in Table C.7, Annex C.

4.6.2. Results

4.6.2.1. Scenario 1 – Baseline case

In the energy and AS joint market, the power flow that each service implies in the network must be adapted to the technical constraints of the network and services. In this regard, the energy and AS market simulation is sequentially executed in order to ensure the feasibility and reliability of the power system.

The simulation process comprises the phases described in the introduction model of the section 3.5. Thus, for energy, RU and SP services Bialek methodology is used to determine the Bialek topological factors based on the power flow of each service, restrict network resources with the purpose of preventing network congestion. The final dispatch results of the joint simulation are based on the calculated limits during the process. Hereupon, Figure 4.12 illustrates the energy dispatch for the 24-hour period and the subsequent portion of the resources used in the dispatch.

The percentage of influence that each resource type comprises the energy dispatch is given by Figure C.1 of Annex C. This figure provides a simplistic overview of the share that each kind of resource has in dispatch. In the energy dispatch the share supplied by DG resources is significant, although much of the energy is provided by the external supplier.

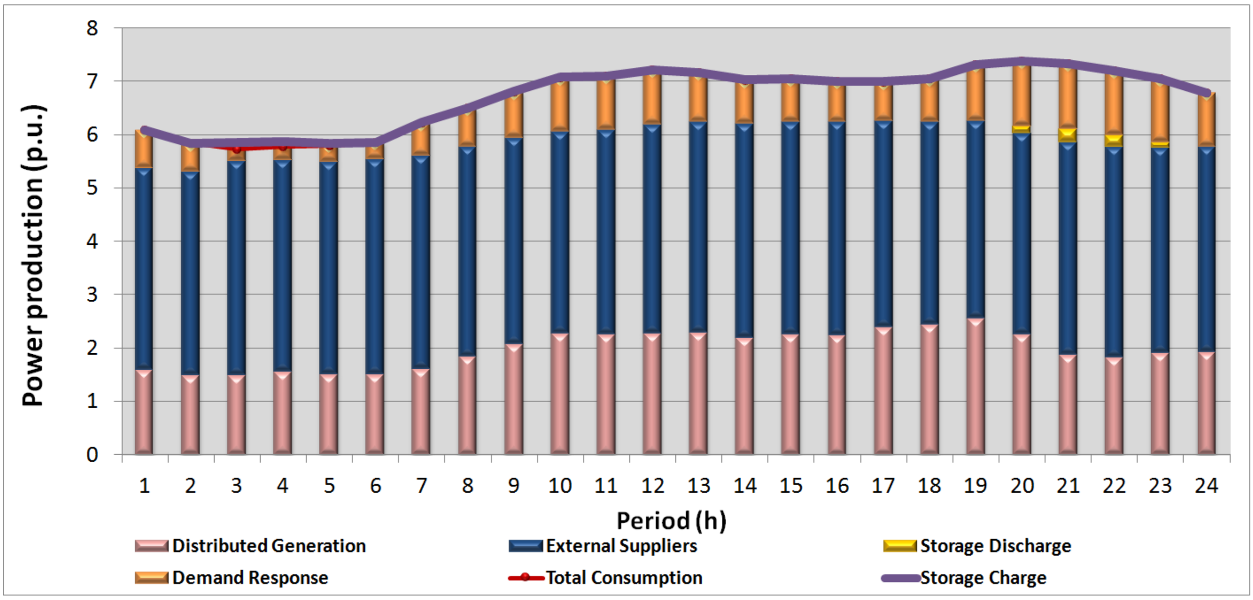

Figure 4.12 – Energy dispatch by type of resource, in scenario 1 of joint market model applied by VPP.

As it is known, the DG comprises several production technologies. Therefore, Figure 4.13 illustrates the amount of energy which was supplied by each DG technology to the energy dispatch, while Figure C.2 of Annex C illustrates the percentage contribution of each DG technology to be more easily perceptible the importance that each technology has on energy dispatch for each hour period.

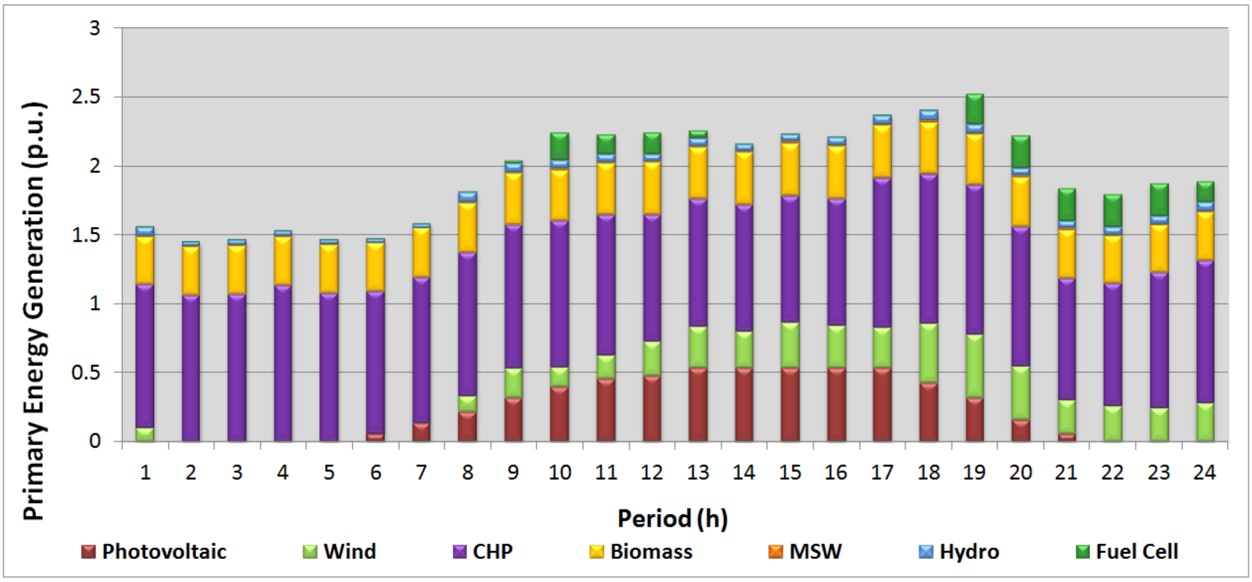

Figure 4.13 – Energy dispatch by distributed generation technologies contribution, in scenario 1 of joint market model applied by VPP.

The DR is an important resource which contributes to the balance of the system. As seen in Figure 4.12, the DR was activated, reducing the amount of load to be supplied. However, this resource is divided into two types, as mentioned in the previous subsection. In this way, Figure 4.14 shows the dispatched amount of each type of DR, and the portion of resulting load being supplied by the generators and external suppliers. The resulting load is obtained by subtracting the sum of DR against the requirement of load initially required by the VPP.

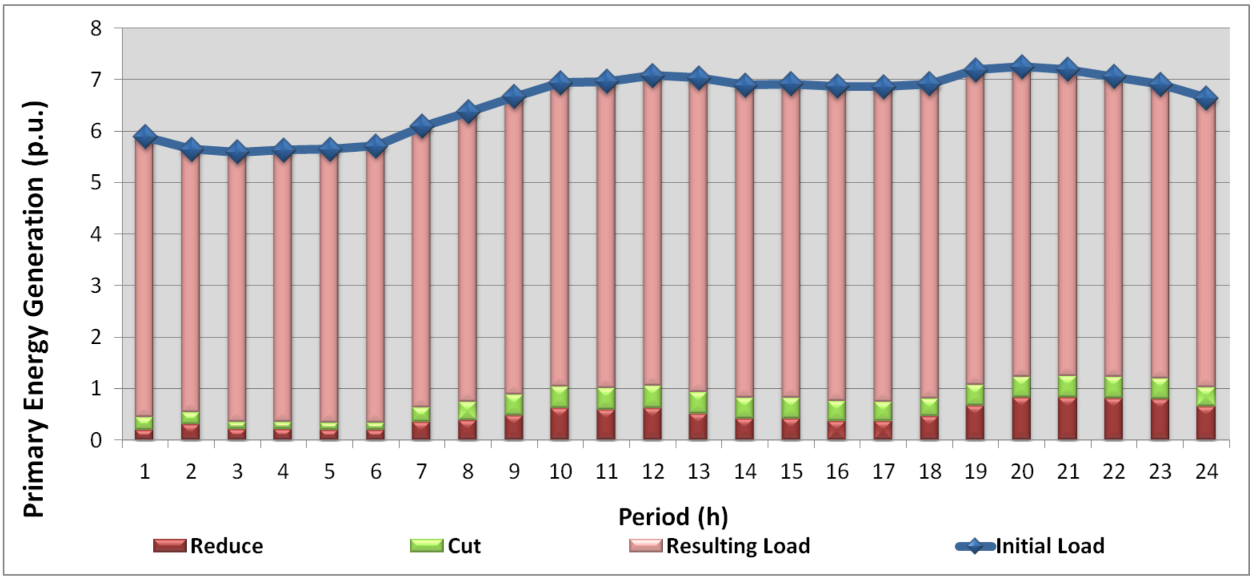

Figure 4.14 – Type of DR for energy dispatch, in scenario 1 of joint market model applied by VPP.

In Annex C, Figure C.3 presents the percentage contribution of the type of DR in energy dispatch for each period. In what concerns the ancillary services, the dispatch of each service is represented by Figure 4.15, Figure 4.16, Figure 4.17 and Figure 4.18.

Figure 4.15 represents the Regulation Down dispatch in accordance with the service required by the VPP. The contribution that each resource gives to the RD dispatch is shown in Figure C.4. In periods 17 to 20, there is a large contribution of external suppliers in the RD dispatch. This contribution is due to the fact that in these periods the price of external suppliers is lower for upstream and downstream periods of this range. Also in this context it seems that CHP units price (main DG technology providing the dispatch) are higher when compared with other periods.

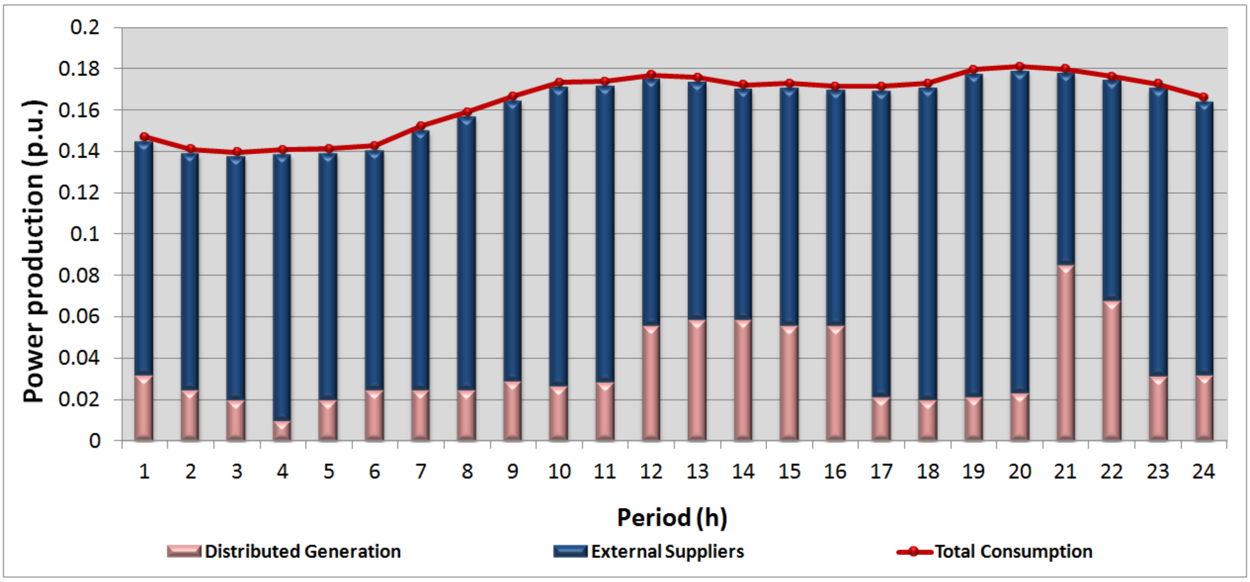

Figure 4.15 – Regulation down dispatch, in scenario 1 of joint market model applied by VPP.

Regarding the Regulation Up service, Figure 4.16 illustrates the RU dispatch for each hour. In this figure it is possible to see the participation which DG resources have in service dispatch. Considering the total energy dispatched in 24 periods of one hour, based on Figure C.4 it is known that DG satisfies the requirement of Regulation Up required by the VPP in the market, about 28%, which implies that the remaining part is provided by the external supplier.

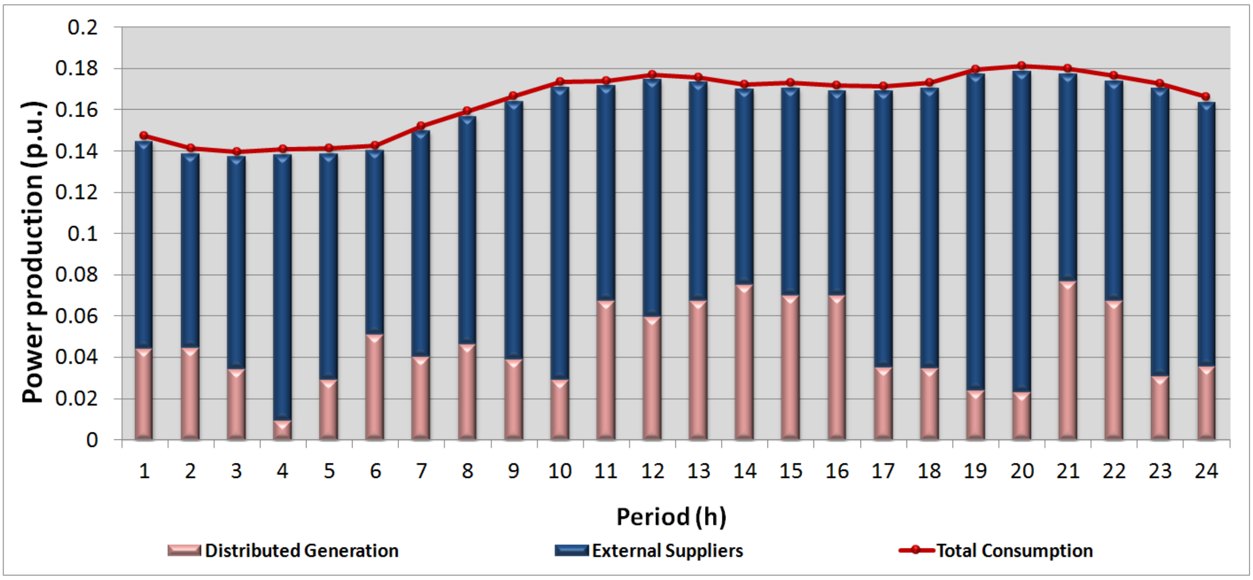

Figure 4.16 – Regulation up dispatch, in scenario 1 of joint market model applied by VPP.

The dispatch regarding the SP reserve is represented by Figure 4.17. In Annex C, Figure C.4 presents the percentage of energy that each resource type supplies to the Spinning Reserve requirement.

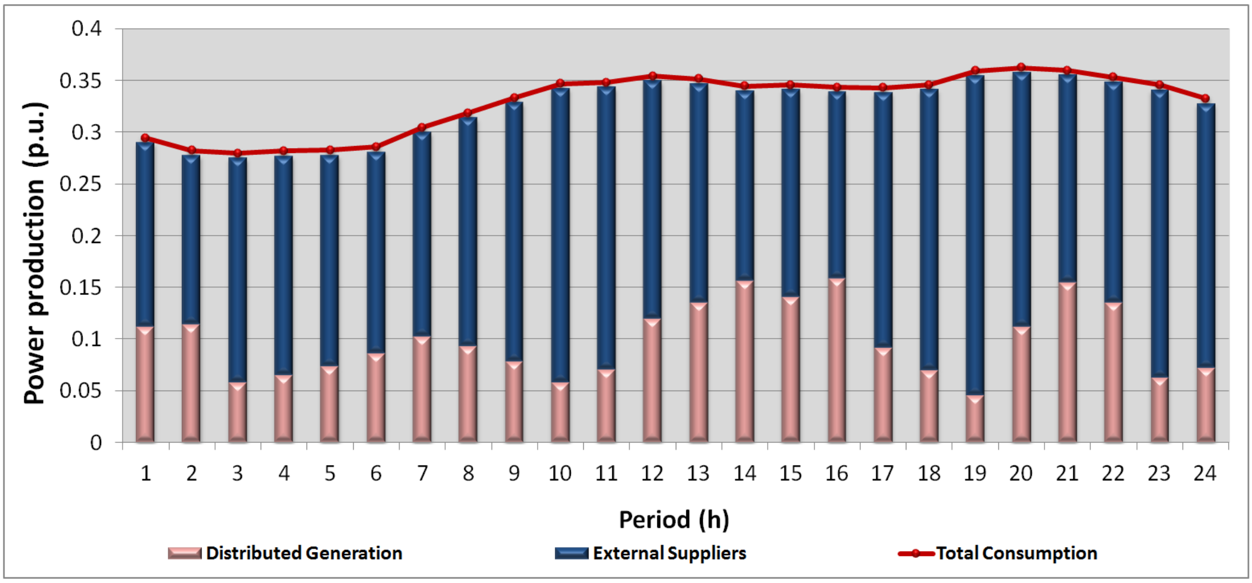

Figure 4.17 – Spinning reserve dispatch, in scenario 1 of joint market model applied by VPP.

Figure 4.18 represents the NS dispatch. The overall contribution which DG and external supplier provides for the service is shown in Figure C.4 of Annex C.

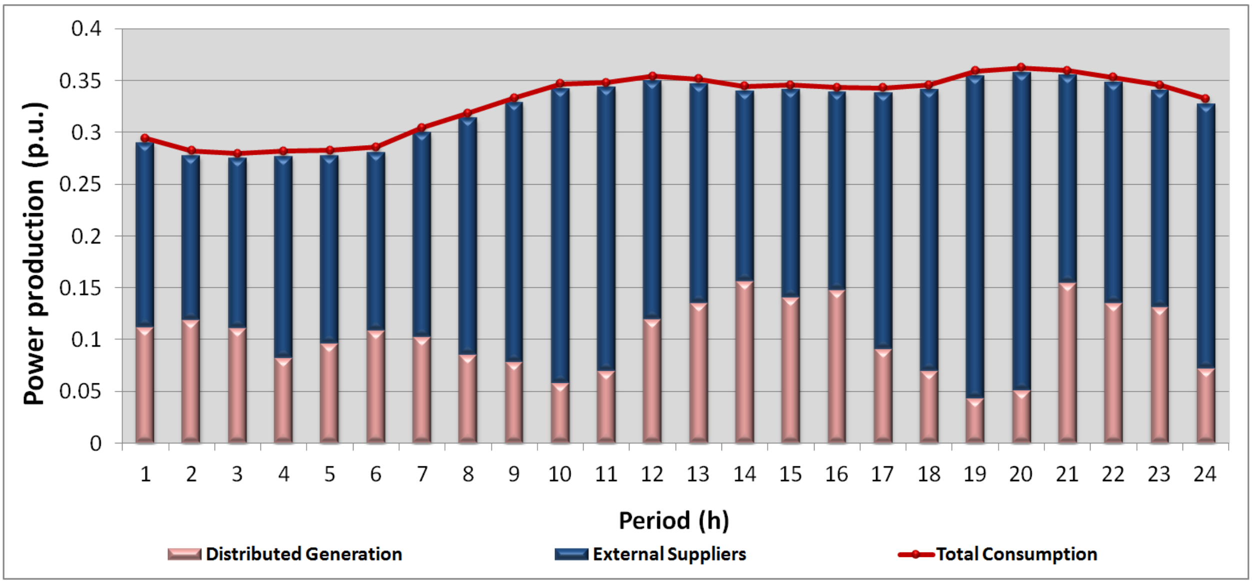

Figure 4.18 – Non-spinning reserve dispatch, in scenario 1 of joint market model applied by VPP.

With these figures which represent the dispatch for each service, it is possible to highlight some variations in the energy and AS dispatch, since the maximum capacity of each bid is conditioned according to the maximum power limit constraint for the services of production addition, concerning the model of section 3.6.

4.6.2.2. Scenario 2 – Base case with different bidding regions

The division of AS requirements by network regions has as primary goal the prevention of any congestion in the network. Therefore, the areas of the network where their lines have high probabilities of congestion are delimited. In this way, the methodology implemented becomes important, preventing from network problems. However, the solution becomes more expensive from the viewpoint of the dispatch of resources, since at least 50% of each AS requirement must be provided for the resources of this region. Thus, in order to be able to compare the results obtained with the base case in section 4.6.2.1, the dispatch of each AS for each region can be exposed in a global view.

The energy dispatch for the scenario described in this subsection is shown in Figure 4.19, in which it is possible to verify that there was a decrease in the resource use of DR and discharge of storage units, compared to the scenario presented in the previous subsection. This is due to the simple fact that the maximum limit of overall production has been changed in this scenario, in which the maximum limit of overall production corresponds exactly to the sum of the maximum limit of each service of increase generation. In this way, the DR and storage resources are typically more expensive than some of the DG resources. Thus, it originates a bigger contribution of the DG resources to the energy dispatch than the DR resources.

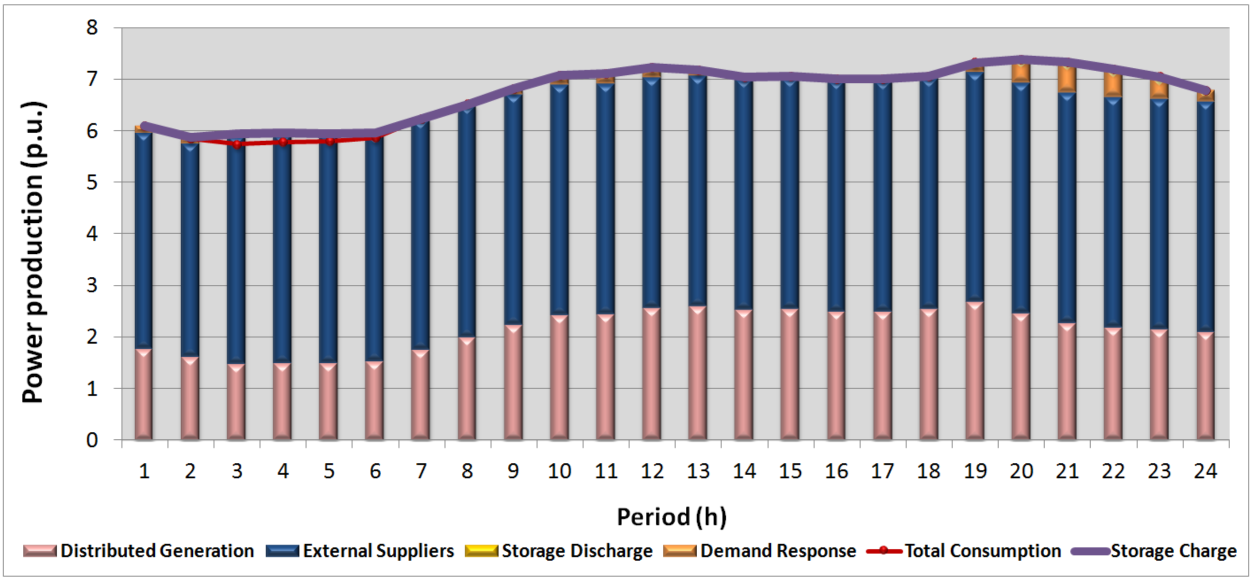

Figure 4.19 – Energy dispatch by type of resource, in scenario 2 of joint market model applied by VPP.

In Annex C, Figure C.5 represents the percentage that each type of resource has in the energy dispatch. Figure C.6 and Figure C.7 show the contribution and importance that each type of DG technology has in energy dispatch, respectively. These graphs allow identifying in detail the variation of the generation cycle of each kind of resource over the period of one day. The amount of types of DR dispatched is given by Figure C.8 and Figure C.9 in which it is visible the low priority that this kind of resource has in this scenario. This is due to the increase in the maximum limit of global generation, which allows the use of larger amounts of power in energy dispatch on the part of generators.

Regarding the AS dispatch, the market simulation is performed for each of the regions, in order to obtain the global AS dispatch in the network. This implies that each region has its own AS dispatch. Accordingly, in order to be able to observe the impact which this methodology has in the scope of global ancillary services, Figure 4.20 illustrates the amount of generation dispatched by the generators of the different regions for Regulation Up service. In turn, the Regulation Down dispatch is provided in Annex C, Figure C.10.

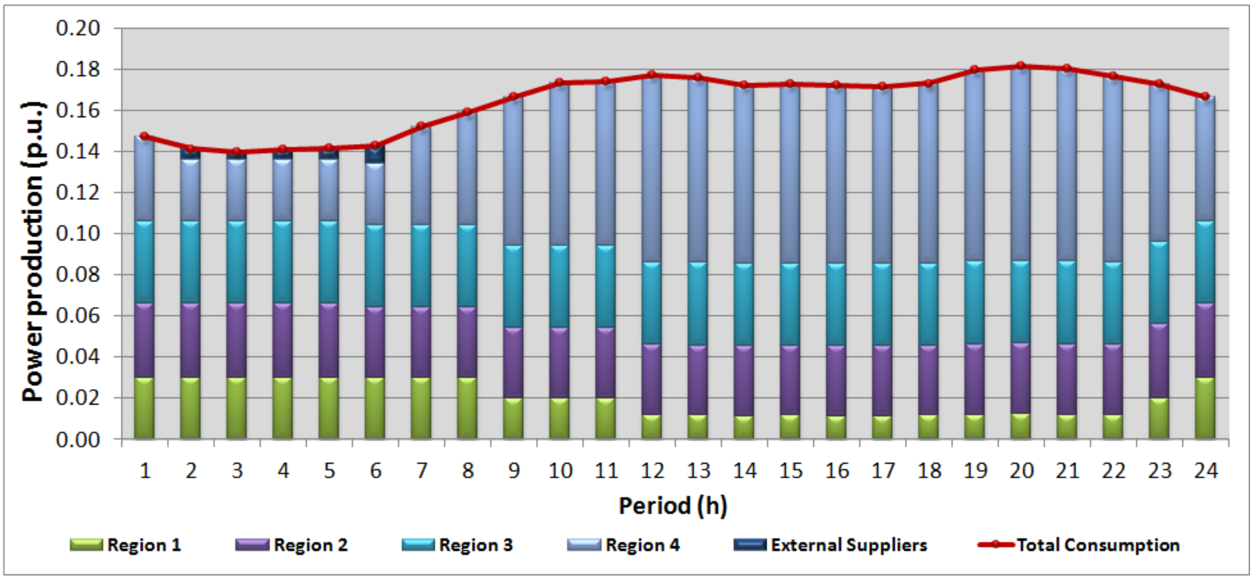

Figure 4.20 – Overall regions regulation up dispatch.

In each region, the generators from the region are forced to provide at least 50% of the RU requirement for this region. This implies that regions in which the production cost is lower than other regions, will have a tendency to produce more than the necessary for their service in order to deliver energy to other regions according to the network technical limits. These events are easily visible in Figure 4.21.

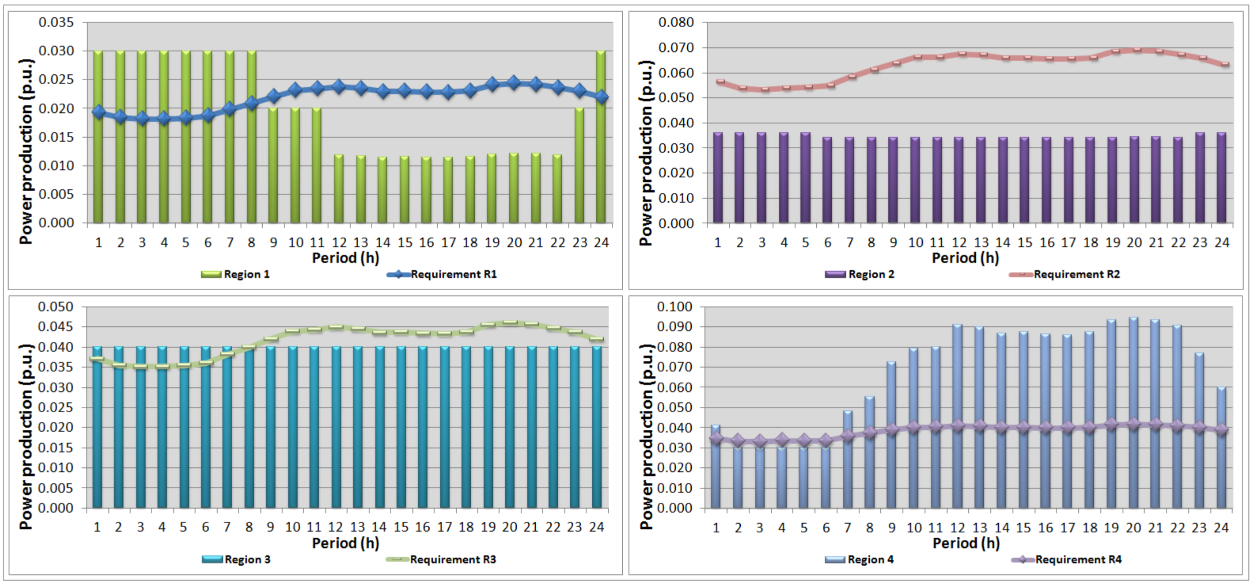

Figure 4.21 – Regulation up dispatch by each region.

For periods 1 to 8 and 24, the generation of all resources in Region 1, dispatches more output than the limit required by the VPP for this region. However, the opposite happens in periods between period 12 and period 22 in which the power generation by the generators of the Region 1 is roughly half of the requirement required by the VPP, implying the need to import from other regions. For the remaining periods (period 9 to 11, and 23), the respective requirement is mostly supplied by internal generation units of Region 1. However, it needs some imports from other regions. Region 2 in all periods need to import, since in most periods the internal resources only supply little more than 50% of the AS requirement. The greatest part of the import of the Region 2 refers to export of the Region 4. This is because Region 4 has some CHP units with a generation capacity significantly higher than CHP units from Region 2. As this kind of resources are generally the cheapest resources, they assume a large contribution in the AS dispatch in the network. This difference of generation in each region could be clearly superior to that achieved, if it was not considered a constraint concerning a certain amount of regional AS requirement be provided by internal resources of the region. With this rule, the VPP ensures that the interties between regions suffer less congestion, thus ensuring a lower dependence on certain resources and, as a consequence, a greatest reliability of the system.

It should be emphasized that exporting energy in any region is only available for resources, in case that the requirement of their respective region is fully satisfied by internal resources.

The global dispatch related to the resources of DG technologies and external supplier for the RU service is given in Figure C.11 of Annex C.

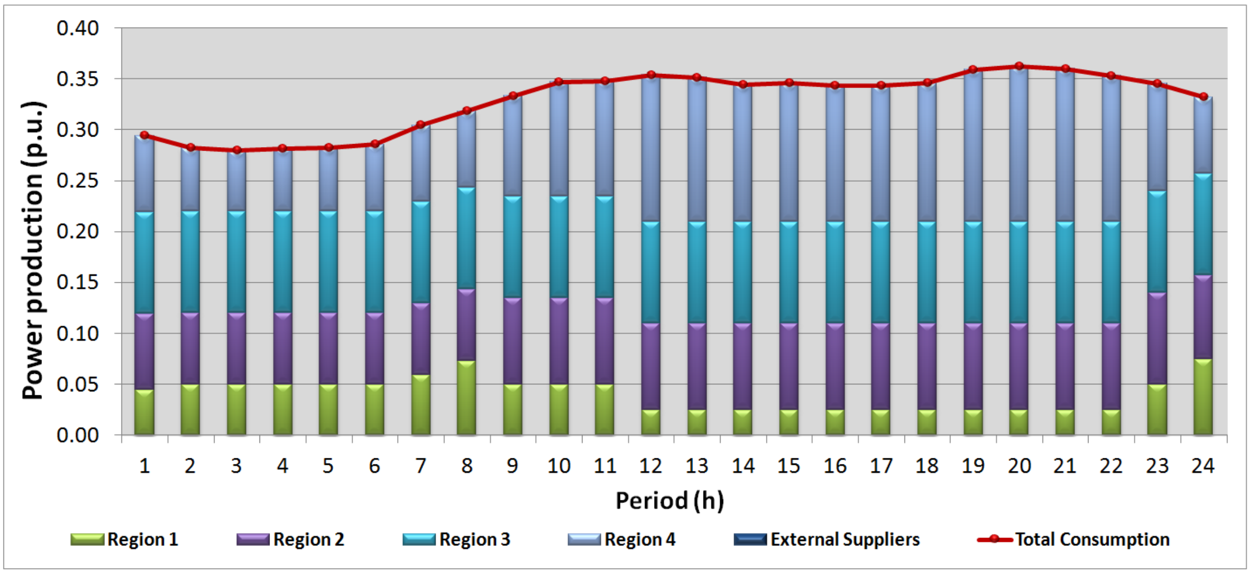

Figure 4.22 – Overall regions spinning reserve dispatch.

Following the same principle of presentation and explanation of the Regulation Up reserve, the Spinning and Non-Spinning reserves are simulated in the same way. For the

Spinning reserve, the overall dispatch is represented by Figure 4.22. The dispatch which concern the AS requirement imposed by the VPP for each region is shown in Figure 4.23.

In the Spinning reserve dispatch, the external supplier is not dispatched at any period of the simulation. This is due to the combination of possibilities inherent to the optimization process. For this service, it seems that Regions 3 and 4 are exporting regions with a large impact, mainly in the supply of Region 2 requirement, which remains a typically import region.

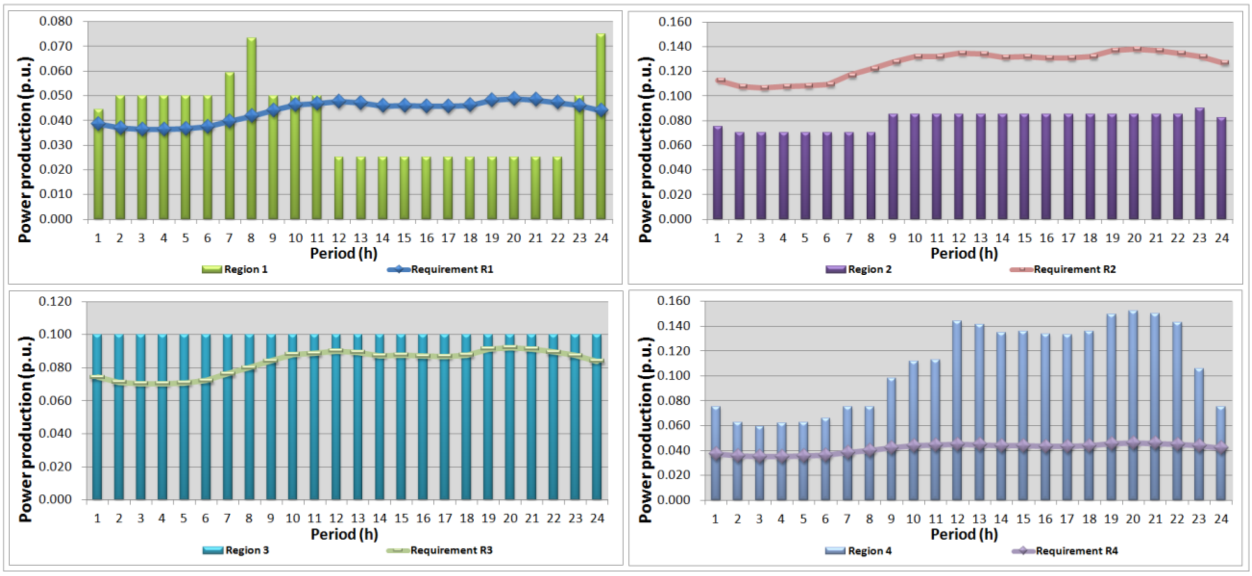

Figure 4.23 – Spinning reserve dispatch by each region.

The global Spinning Reserve dispatch is shown in Figure C.12 of Annex C.

With regards to Non-Spinning service, the global dispatch for this service is illustrated by Figure 4.24, while the dispatch for each region and its requirement is represented in Figure 4.25.

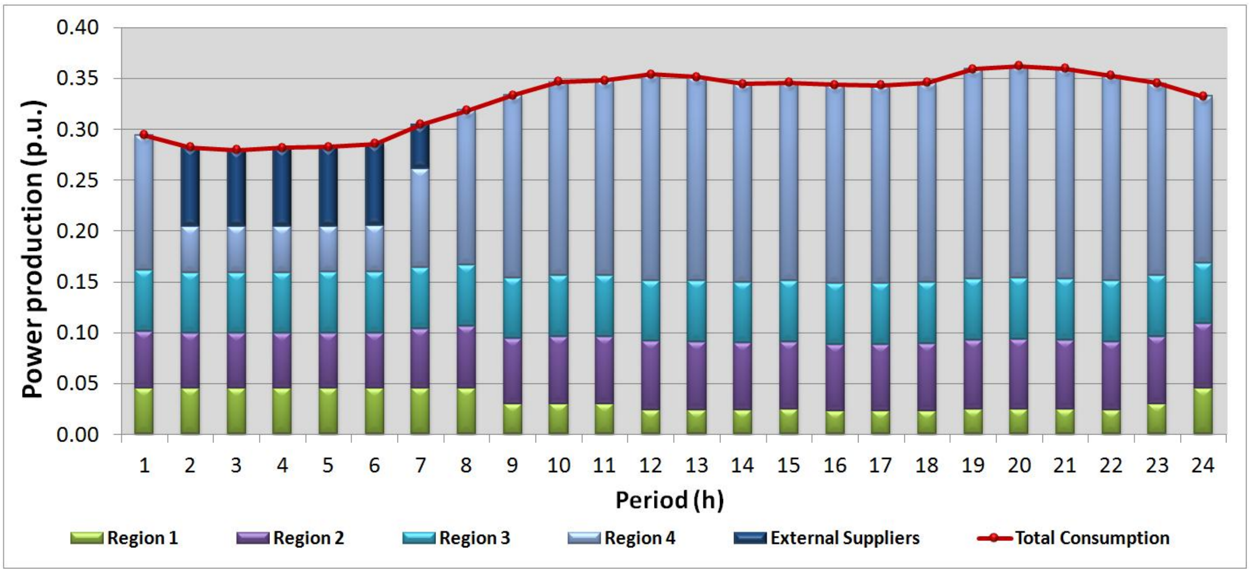

Figure 4.24 – Overall regions non-spinning reserve dispatch.

Regarding the Non-Spinning reserve dispatch, the results show that a considerable part of the energy necessary to dispatch this service between periods 2 to 7 is provided by the external suppliers. This is due to a set of specific situations. First, the limit of production implemented in the model based on Bialek factors, which do not allow that the production of each energy resource for Non-Spinning reserve exceeds the limits calculated in order to make the energy and ancillary services joint dispatch unfeasible. Another frequent situation arises when the overall maximum limits of a generator is reached (the sum of production dispatched to services of energy, RU, SP and NS reach its maximum production capacity). These two conditions combined give rise to the need for dispatching external suppliers and, expensive generators with some freedom of production to meet the service requirements for each region.

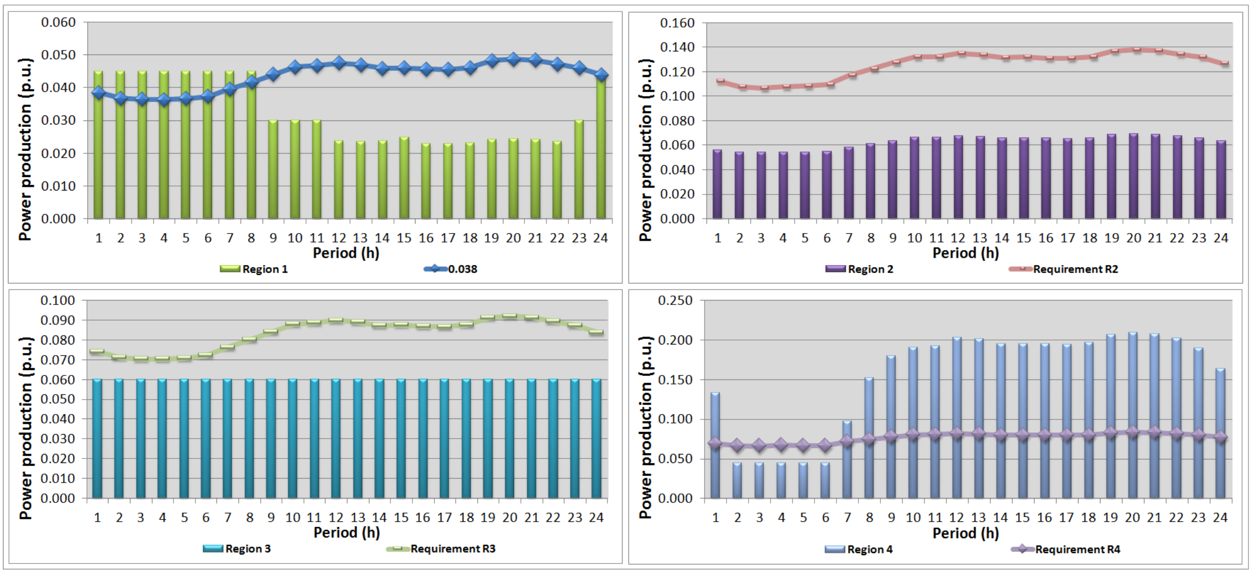

Figure 4.25 – Non-spinning reserve dispatch by each region.

In Annex C, Figure C.12 illustrates the global dispatch of the service considering the types of resources surrounding the dispatch of the referred service.

4.6.2.3. Scenario 3 – DR resources and RLXD variable on AS dispatch

In this scenario the results for the introduction of the types of DR and relaxation variables of the problem for the ancillary services are presented. From the point of view of energy service, this scenario does not involve significant changes in the energy dispatch, this occurs due to the maximum limits of resources for the energy service that has not changed. In this way, the results and conclusions of this scenario focus on the AS dispatches.

The Regulation Down dispatch does not consider the use of types of DR established in the model. The types of DR consider only the load reduction, which is infeasible for the

RD service. This service hires resources to reduce generation or increase the consumption in the network. Thus, the proposed types of DR are not suitable for this service.

In this context, Figure C.13 and Figure C.14 in Annex C provide the dispatch and their percentage of contribution of each resource to the RD service.

With regards to the Regulation Up service, the contribution of Demand Response is quite considerable. In Figure 4.26 it is possible to see a large participation of DR in regional dispatch of RU. In this way, the types of DR are fairly useful for the RU dispatch, thereby reducing the operation cost compared to the service requirement, if provided only by DG technologies and external suppliers. In Annex C one can find the global dispatch of the RU reserve in Figure C.15.

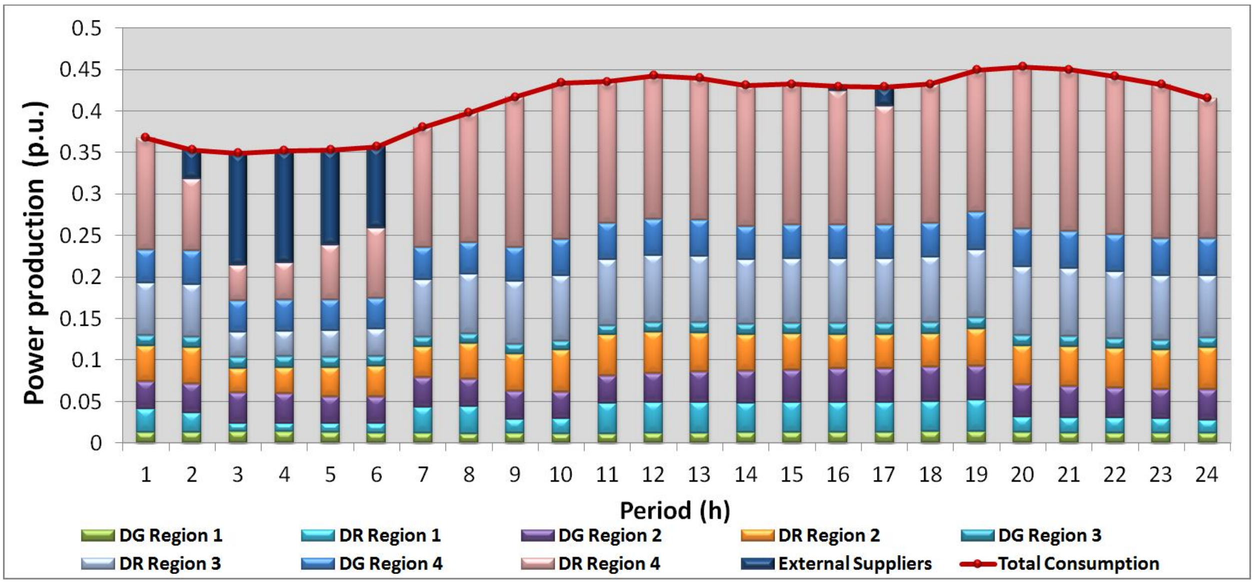

Figure 4.26 – Regulation up dispatch considering DR resources.

In the context of the widespread use of DR for RU service and for each region of the network, Figure 4.27 presents the contribution of each Type of DR in each region for this service.

Depending on the region, the contribution of each Type of DR may vary considerably. For example in Regions 1, 2 and 3 there is a greater participation of DR Reduce type, while in Region 4, the DR Cut is clearly superior to the DR Reduce. Briefly, the Demand Response Cut type to the loads of Region 4 is less expensive, and has, therefore, a greater contribution in the regulation up dispatch.

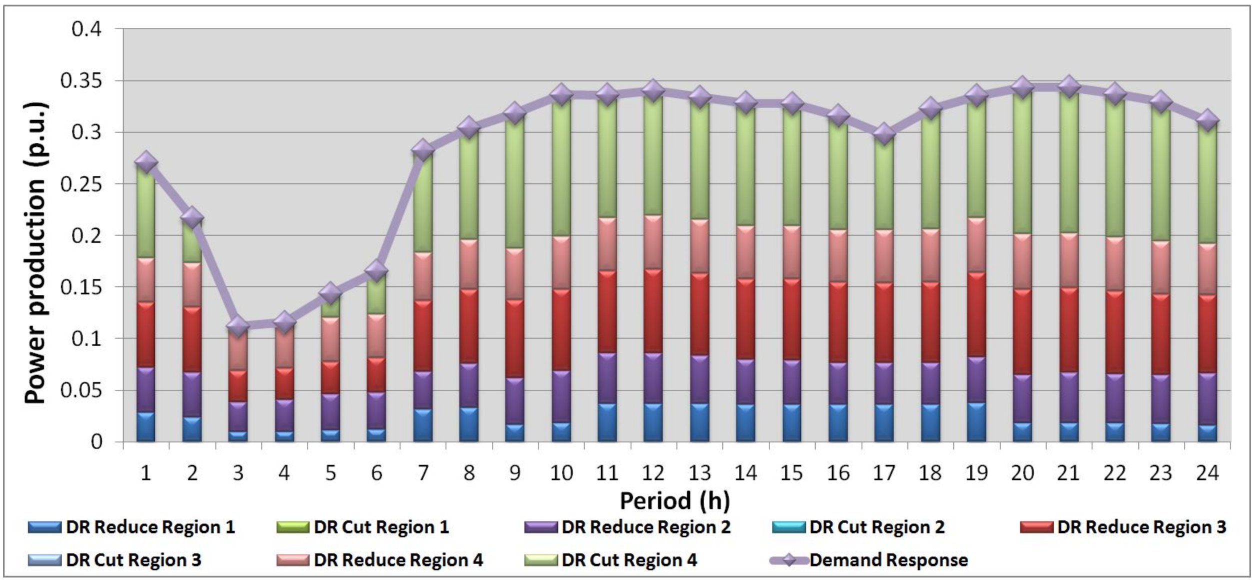

Figure 4.27 – Types of DR dispatch in each region for RU service.

With regards to the Spinning Reserve dispatch, Figure C.16 of Annex C illustrates the global dispatch of SP service, in which can be seen the impact that the DG, DR and external suppliers has in the dispatch. Following this perspective, the contribution of each type of resource by network region is shown in Figure C.17 of Annex C.

The maximum capacity of each DR resource in this service is equivalent to 10% of the maximum capacity for the same resource for the Regulation Up service. In this way, for the SP service the DR was fully used, implying that to satisfy the regional requirement it is required more power of the DG and external suppliers, as compared to the RU service. Thus, based on Figure C.16, it is concluded that the DR and external suppliers are a crucial part of the SP dispatch, since the maximum capacity generation of DG resources in both services (RU and SP) is similar.

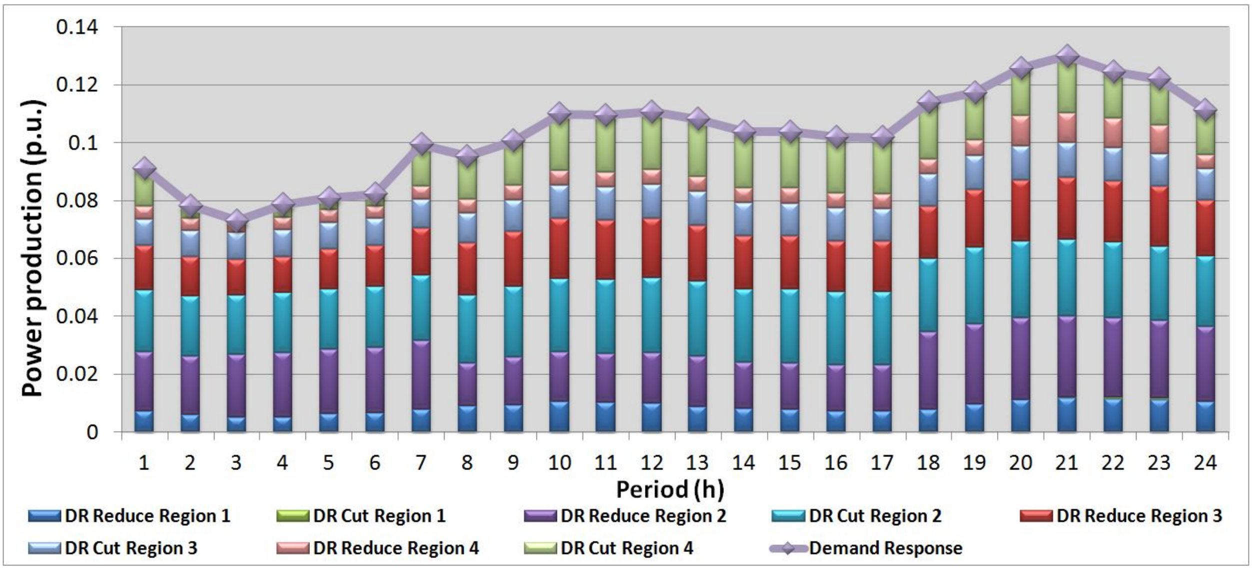

Figure 4.28 – Types of DR dispatch in each region for SP service.

Figure 4.28 illustrates the DR dispatch by network regions for the SP service. Comparing Figure 4.28 with Figure 4.27 (concerning the RU dispatch) one can see an increased contribution of the DR Cut type in regions 2 and 3.

In this context, the use of almost the total generation capacity of DG and DR resources leads to the availability of using relaxation variables when resources fail to generate enough energy to supply the load.

The use of relaxation variables are typically used in two different ways. Firstly, the relaxation variables can only be used in the optimization process as a means for the VPP to identify the situation in which the dispatch is infeasible, creating a problem to VPP towards solving the problem of infeasible solution.

Secondly, the VPP knows through the relaxation variables what are the problems of the dispatch, and through bilateral contracts with generation units it ensures the feasibility of the dispatch. This is the way normally used by the ISO or VPP to solve the problem of the infeasible dispatch.

The model developed presents a third way of looking at the problem, which consists in the procurement of resources in the market optimization that could contribute to the feasibility of the dispatch regarding all regions. However, from the beginning one does not know in which regions of the network these situations can happen. In this way, it is possible to implement a constraint on the model which uses the resources of other regions of the network to meet the requirement of a particular region.

In this context, Figure 4.29 shows the Spinning Reserve dispatch of region 2 in which is evident the use of the relaxation variable RLXD.

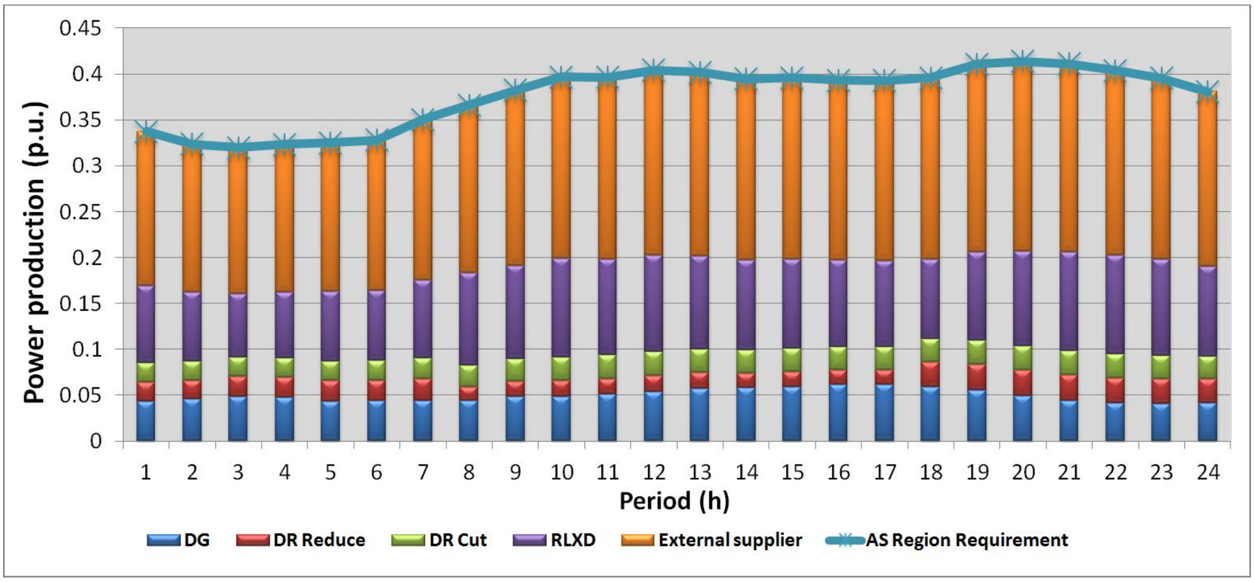

Figure 4.29 – SP dispatch in region 2, by each resource.

In this case, the relaxation variable will be entirely provided by the external supplier, because the DG and DR were completely used in all regions of the network. All internal resources of region 2 have insufficient capacity to provide at least 50% of the Spinning requirement of its region. In this way, the generation provided by the external supplier for the variable is remunerated at a high price, in which the relaxation variable is only used to achieve the 50% of the regional AS requirement, since it is mandatory to offset at least 50% of requirement be provided by the internal resources of the region. It can be concluded that the relaxation variable complements the needs of generation in case of internal resources of the region being insufficient to provide partial or full regional AS requirement.

The respective regional dispatch to the remaining network regions can be found in Annex C, Figure C.18, Figure C.19 and Figure C.20.

Regarding to the Non-Spinning reserve dispatch, one can verify that the DG and DR generation are practically sufficient to meet the load in all time periods except for the period corresponding to hour 3.

In this way, the regional NS service dispatch is illustrated in Figure 4.30 (the global dispatch of the service by all kind of resources is shown in Figure C.21 and presented in Annex C).

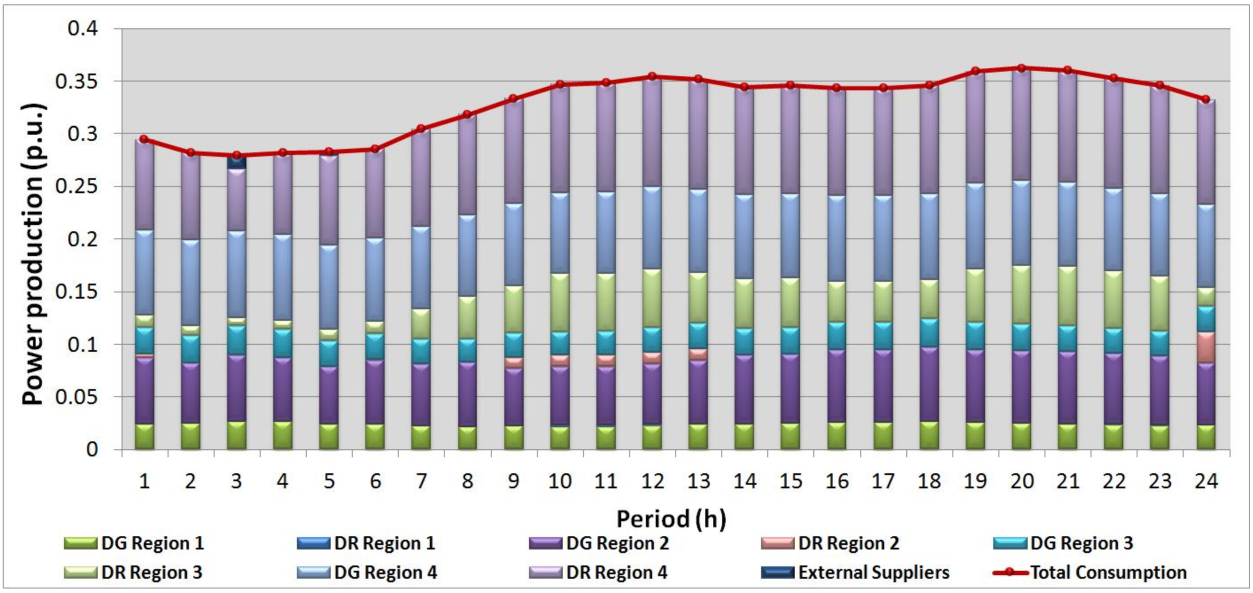

Figure 4.30 – NS dispatch by network regions, considering DR resources.

Regarding the contribution of DR in this service dispatch (Figure 4.31), it seems that regions 3 and 4 cover a greater sharing of types of DR while regions 1 and 2 contemplates greater involvement of DG in these regions dispatch. This is mainly due to the price and generation capacities provided by DR resources in certain regions of the network.

The types of DR can be very useful in the stability of power systems. Through the scenario presented is clear the need to consider these resources in the complex managing of ancillary services.

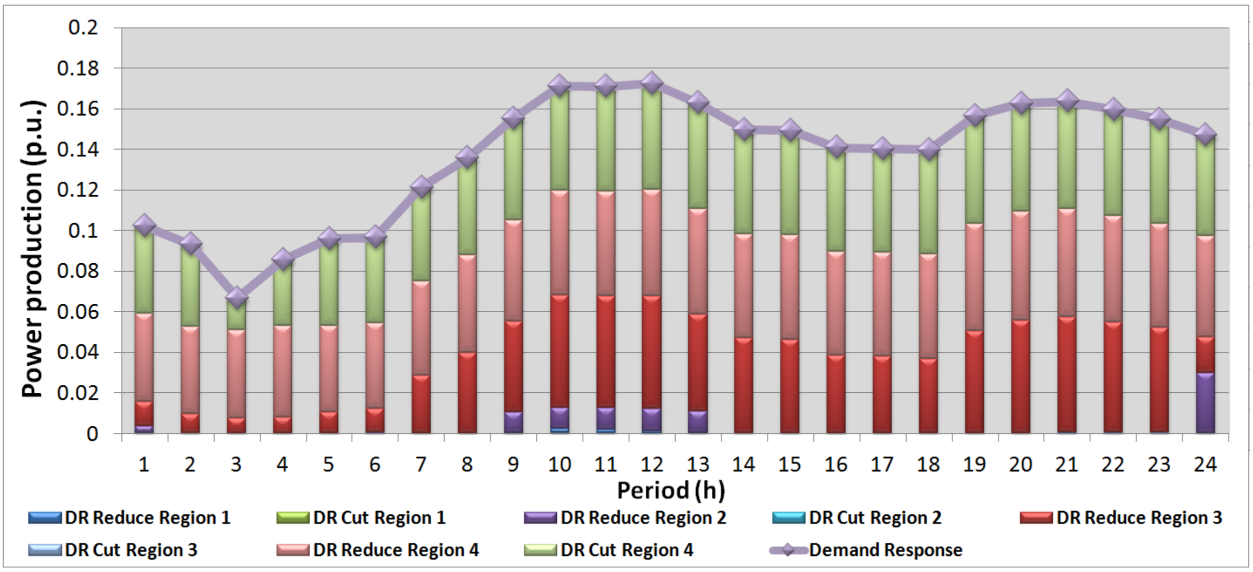

Figure 4.31 – Types of DR dispatch in each region for NS service.

These resources may reach a more economical management of the energy and AS joint market. However, it is important to note that the excessive use of a particular resource type is not good for the stability and management of all kind of resources in the power systems. Briefly, this scenario shows the potentiality of DR in a efficient ancillary services dispatch, as well as the use of generators in special cases, such as situations in which the internal energy generation in a region is not enough to satisfy the AS requirements imposed by the VPP. In these cases, the implemented relaxation variables are a way to ensure the feasible dispatch of ancillary services.

4.6.2.4. Scenario 4 – Storage units on AS dispatch

The introduction of storage units in the energy and AS joint procurement is critical to the proper management of network resources. Due to its particular characteristics, the storage units can adapt properly to the AS. Their ability to charge and discharge energy allows a careful management by the VPP regarding the load curve. These resources can be used to charge energy in times of energy excess, as well as discharge energy in peak load situations. In this context, its adaptability to ancillary services is an added value to the VPP management. Therefore, the main function of storage units in the smart grid paradigm is to ensure ancillary services. In this way, the results and conclusions presented in this scenario are mainly directed to the management of these resources in the ancillary services procurement.

The energy dispatch results obtained in this scenario can be found in Annex C, Figure C.22 and Figure C.23. In these figures it is visible a small storage charge in off peak hours, which shows that the energy stored in these hours can be used in ancillary services in other periods.

Regarding the Regulation Down service dispatch, the storage units contribution may be important for increasing consumption levels. Knowing that the RD service is characterized for being a service of decreasing generation that it is required when there is excess generation in the power service, the storage charge variable fits to increase the power consumption. Thus, the storage units fit perfectly the RD service characteristics.

In Figure 4.32 it is possible to see a small contribution of this kind of resource in the service dispatch between periods 19 and 23. In this way, the daily storage units' contribution to this service reaches 0.6% of the daily total requirement necessary.

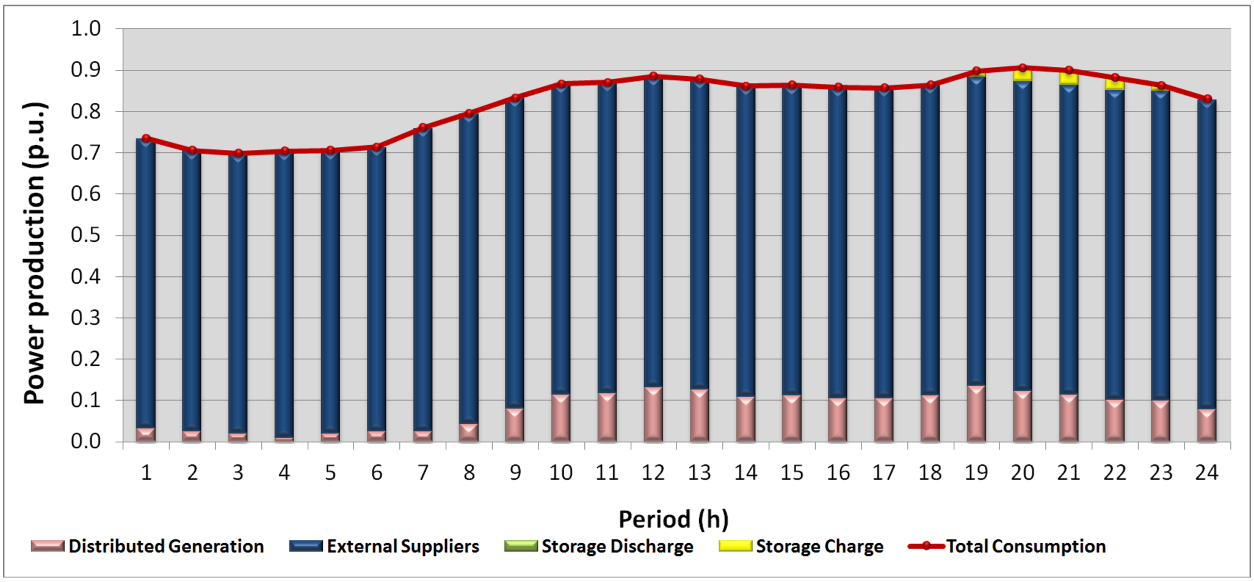

Figure 4.32 – Regulation down dispatch considering storage units.

Regarding the Regulation Up service, the participation of storage units highlights the usefulness of this energy resource in the VPP management.

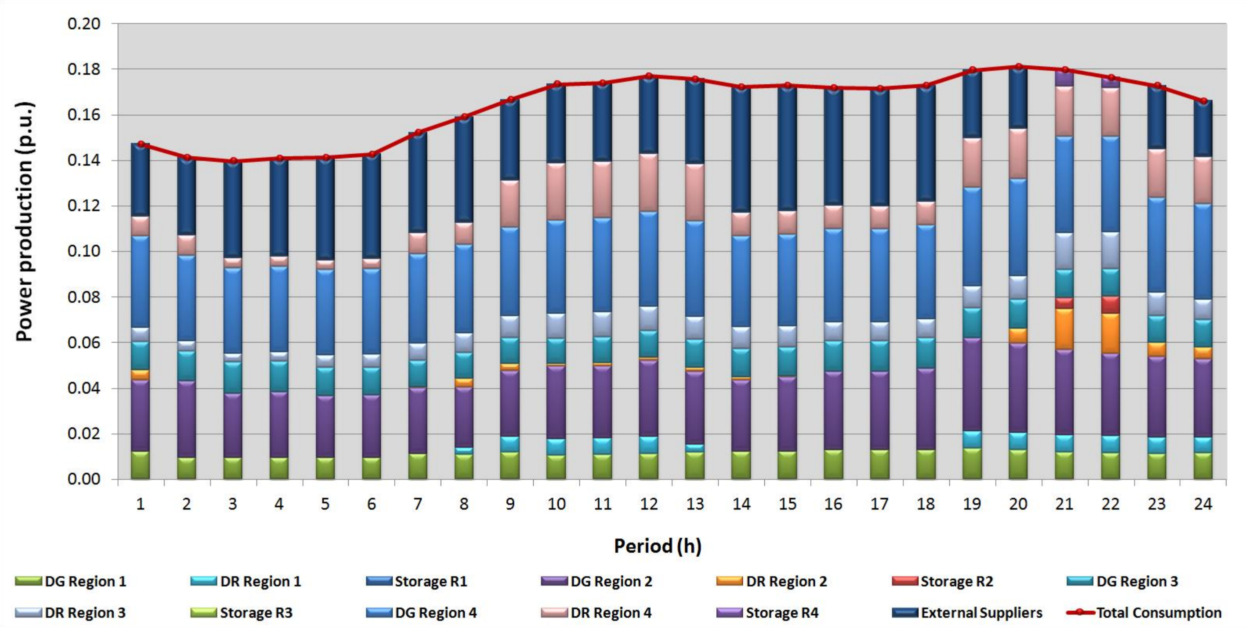

Figure 4.33 – Regulation up dispatch considering storage units by network regions.

Figure 4.33 shows the contribution of these resources in the RU dispatch by network regions. In periods 21 and 22, it is visible the storage units contribution from regions 2 and 4 in the service dispatch. Thus, it appears that there is a large set of several kinds of energy resources from different regions that compete with each other. In these two periods, it was also observed that the external suppliers do not participate in the dispatch. Figure C.24, Annex C illustrates in detail the storage unit participation by network regions, as well as the amount of charge and discharge of these resources in this service.

The storage share in SP service follows the same methodological principle of RU service. Figure 4.34 illustrates the SP service dispatch, considering the DG, DR, external suppliers and storage resources by network regions. In this figure it is possible to see a considerable share of storage in SP dispatch in several periods of the day. This kind of resources contributes in around 10% of the global generation necessary to meet the daily service requirement. The largest share of this resource occurred in period 21 with around 46%, while period 3 corresponds to the period with lower share of around 0.5%. The maximum contribution of storage units in period 21 is justified by the price of external suppliers during this period to be higher than the storage price. The period 21 corresponds to the maximum peak of the external suppliers price in relation to all period range. Thus, it appears that the contribution of external suppliers is lower when compared to other periods.

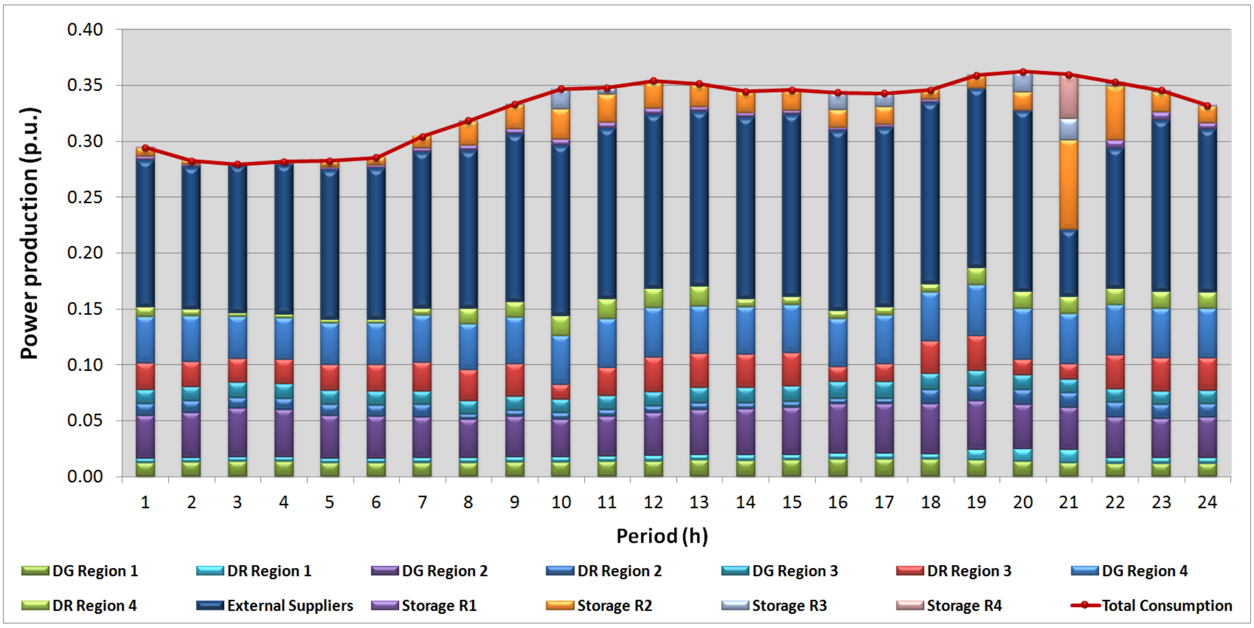

Figure 4.34 – Spinning reserve dispatch considering storage units by network regions.

The amount of energy per network region may be seen in detail in Figure 4.35. One of the ways of storage units to participate in this service involves the discharge of energy. Another way is by decreasing the charge of the storage acquired in energy service; i.e. the storage unit which charge in energy service may participate in the SP service, by reducing the charge that acquired in energy service. This occurred for storage units from region 2 between the periods 3 and 6, with greater emphasis in periods 5 and 6. The storage contribution through discharge energy tends to become more noticeable during peak periods (periods of increased energy consumption). Furthermore, the storage units from region 2 were those which participated with more power to satisfy the service.

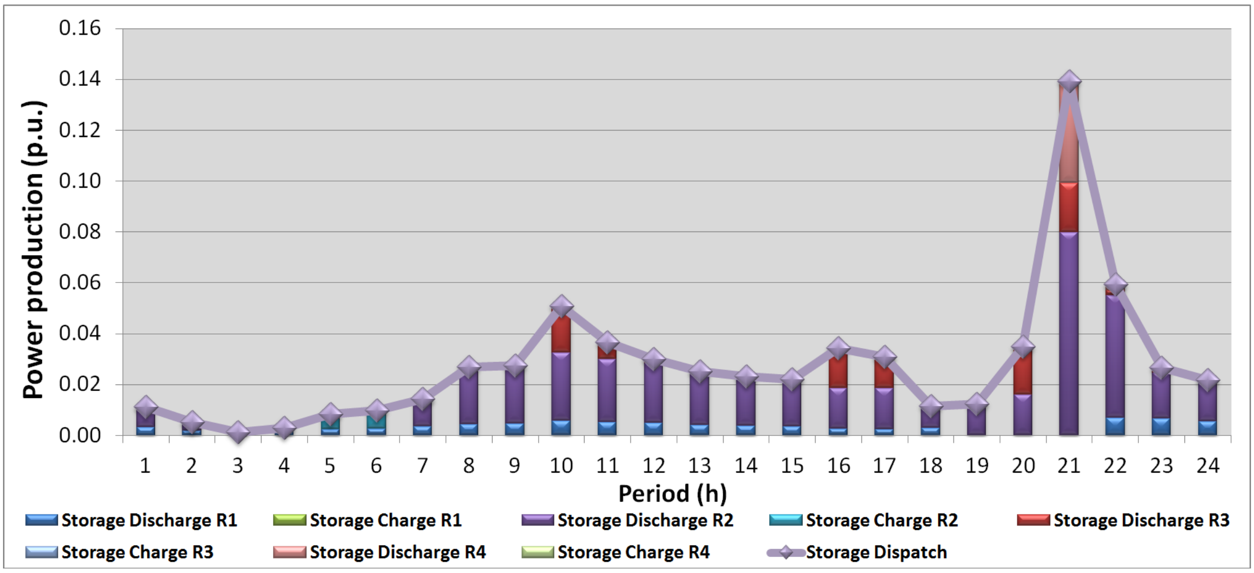

Figure 4.35 – Storage charge and discharge share by network regions for SP dispatch.

Regarding the Non-Spinning Reserve service, Figure 4.36 illustrates the storage, DG, DR and external suppliers' resources participation by network regions in the scope of the NS service dispatch. The storage contribution in the daily service dispatch reached 5% of the total supply of the service. The use of the storage units in the service reduces the need for external suppliers to participate in it.

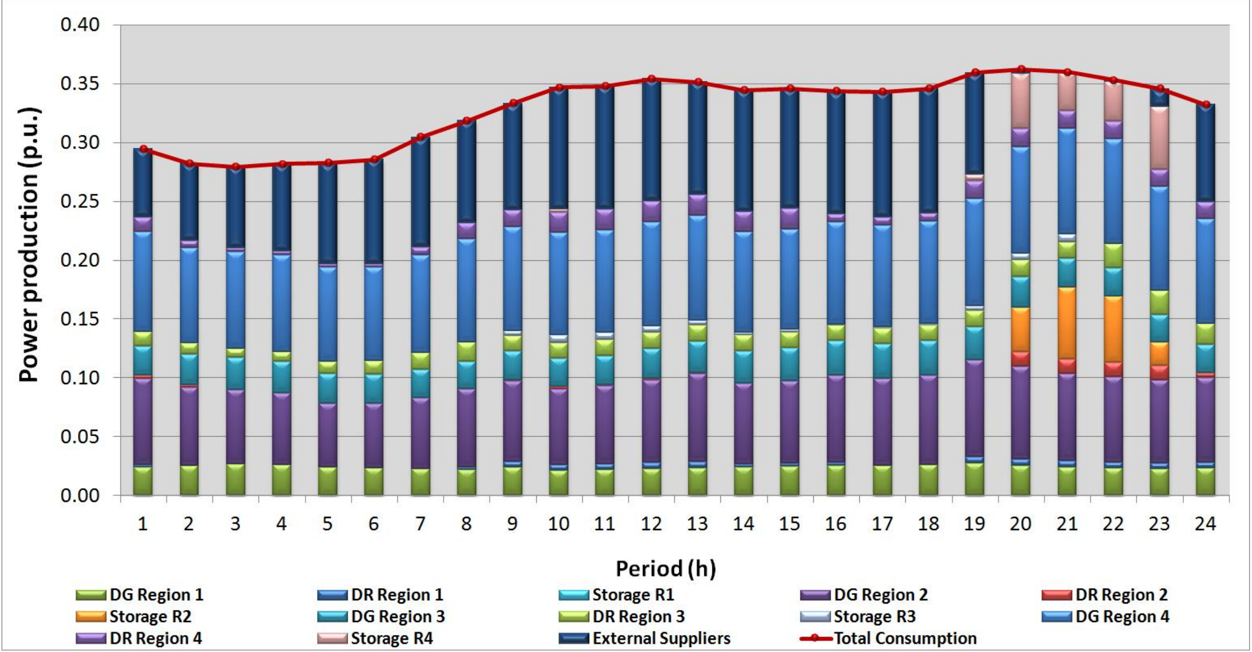

Figure 4.36 – Non-spinning reserve dispatch considering storage units by network regions.

Through Figure 4.37 it is noticeable the involvement of the storage resources from period 9 to period 23, with greater preponderance in the range between 20 and 23. In general, the region which occupies most of these resources to meet the service requirement is region 2. Nearly 43.9% of the total energy supplied by the storage comes from region 2, 43.6% comes from region 4 and the remaining 12.5% are provided by region 3, while the storage of region 1 have no share in the dispatch. In period 21 there is a higher share of storage in the hourly service dispatch – about 32% of the total energy supplied.

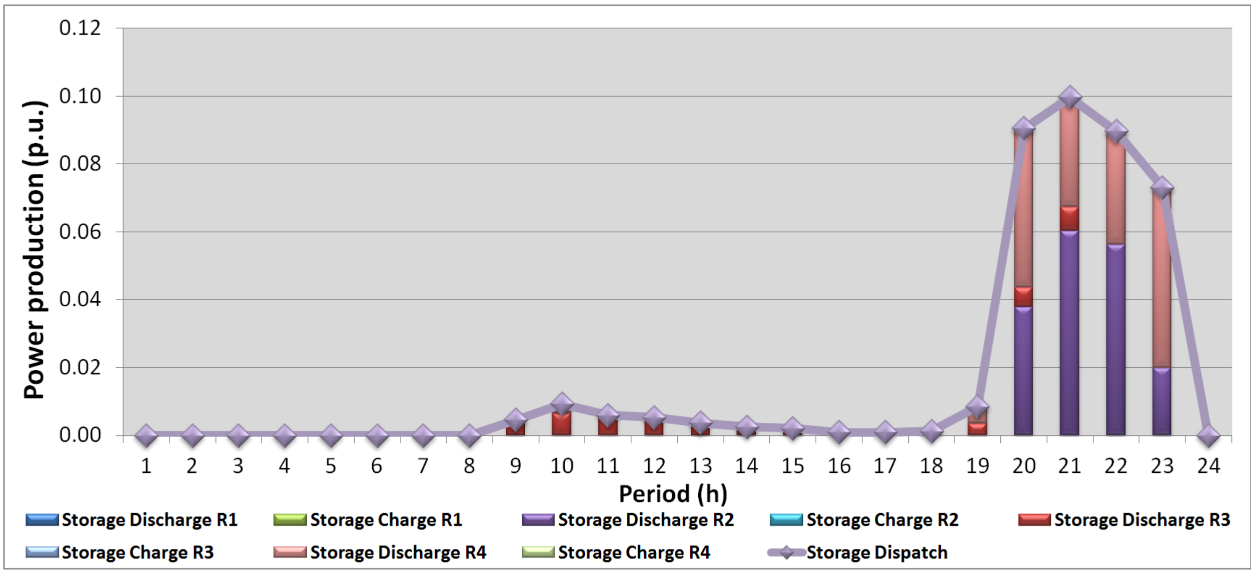

Figure 4.37 – Storage charge and discharge share by network regions for NS dispatch.

4.6.2.5. Scenario 5 – Complex Contracts

The increasing use of distributed energy resources, namely DG, DR and storage units in the power system, requires a continuous adaptability of the management of these resources. In this way, the aggregation of small players with a VPP is especially important for these resources in the competitive environment of the electricity market. However, the aggregation of all kinds of resources is important for the VPP which can have greater amplitude in its strategies during the trade in a competitive environment increasingly complex.

In order to achieve a proper management of the available resources and the goals, the VPP must match the contract conditions established with the resources. However, players can choose from the available set of VPPs which are interested in their aggregation, or to act individually in the smart grid context. In order to encourage the aggregation of the most interesting players, the VPPs need to propose competitive contracts conditions that guarantee competitive benefits to these players [Vale-2011].

This scenario includes all the methodology involving the model presented in section 3.6. Besides the methodology used in the previous scenario, this scenario adds the involvement of several specific and complex contracts, namely the minimum generated energy in period *t* and in time horizon *T*, the power gradient between periods, the minimum remuneration in time horizon *T*, the number of working hours and a maximum number of times that each generator enters in the service.

The application of these contracts is reflected in the scope of the electricity market for the energy and ancillary services. In order to demonstrate the issues that the contracts mentioned above provide to the energy and ancillary services, it was developed a set of simulations capable of illustrating the usefulness of these contractual conditions within the market for both perspectives of the VPP and the owners of power generation units addressed in the distribution network of this case study.

The simulations are based on the input data regarding the base case, with a few changes for each simulation of each type of contract. The set of simulations has the purpose of providing a better perception and understanding of the capacity of each contract of influencing the resource management, thereby accommodating the objectives of the producers and the needs of the VPP.

The first type of contract introduced in this scenario concerns the minimum limit of energy produced by the generator in a 24-hour period, i.e., the contract ensures that the producer, if dispatched, produces at least the minimum limit defined *a priori*.

To simulate this contract, it was established a minimum limit of energy throughout the day by portions of maximum capacity production of the day.

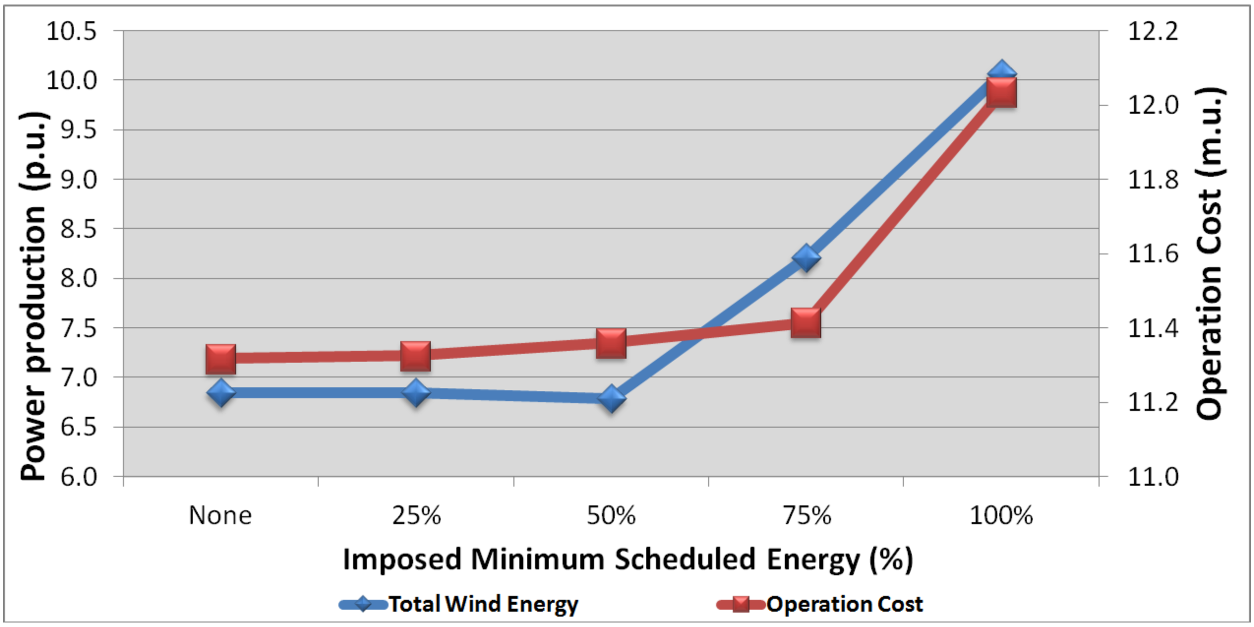

Figure 4.38 – Dispatched energy and operation cost for contract type 1.

Figure 4.38 shows the impact of minimum daily scheduled energy contracts used by wind farms in the VPP operation cost and in the total energy dispatched for producers with this type of contract. The minimum daily energy values imposed in the contracts are based on the wind generation forecast. As it can be seen in Figure 4.38, the scheduled wind energy in the base case already uses a large percentage of available wind energy (almost 50%). However, when it requires the total use of generating capacity of wind energy, it causes a radical increase in the VPP operation costs.

At 75% of the imposed minimum schedule energy, the operation cost does not increase significantly. This is beneficial to the owners of wind turbines, since the considerable increase in power generation (about 17.3%) does not imply a large increase in the VPP operation costs (about 0.48%). Thus, the wind players are quite favoured with this situation.

The second type of contract refers to the gradient of generation in each period. This contract sets for each period of 1 hour a limit for the increase/decrease power generation according to the previous period.

To simulate this contract, one can change the data relating to external suppliers. In this way, it was established a value of power generated by the external supplier for the period prior to the beginning of the simulation.

Knowing that the simulation is performed for the period of 1 hour with a time horizon of 24 hours, the amount of power established for the initial period ($t-1$) corresponds almost to the power dispatched by the external supplier in $t=1$ related to the base case.

Each simulation comprises a value of the gradient of generation relatively small in order to limit very high levels of variation of generation. In this way, the gradient values of generation used for contract simulation vary between 0.25% and 5% of the power dispatched at ($t-1$).

The results of the simulations considering maximum generation gradient contracts applied to the external supplier are shown in Figure 4.39. In this figure it is possible to see the development of the total energy generated throughout the period, and the VPP operation costs, according to the imposed maximum gradient.

It can be concluded that for this scenario the contracts imposing maximum gradient values over 2.50% have a strong impact on the perspective of the operating costs of VPP.

For these cases a variation of the energy produced by the external supplier means a substantial increase in the operation costs. This is caused by the need of the VPP to contract more expensive resources to compensate the generation decrease of production of external suppliers. However, when reducing the generation gradient of external supplier at low levels, the difference in operation costs is not that much relevant because the external suppliers lose importance in the dispatch, since it is necessary to hire more expensive generation units with greater flexibility in variation of the generation between operating periods. This leads to the reduction of the global generation of external supplier.

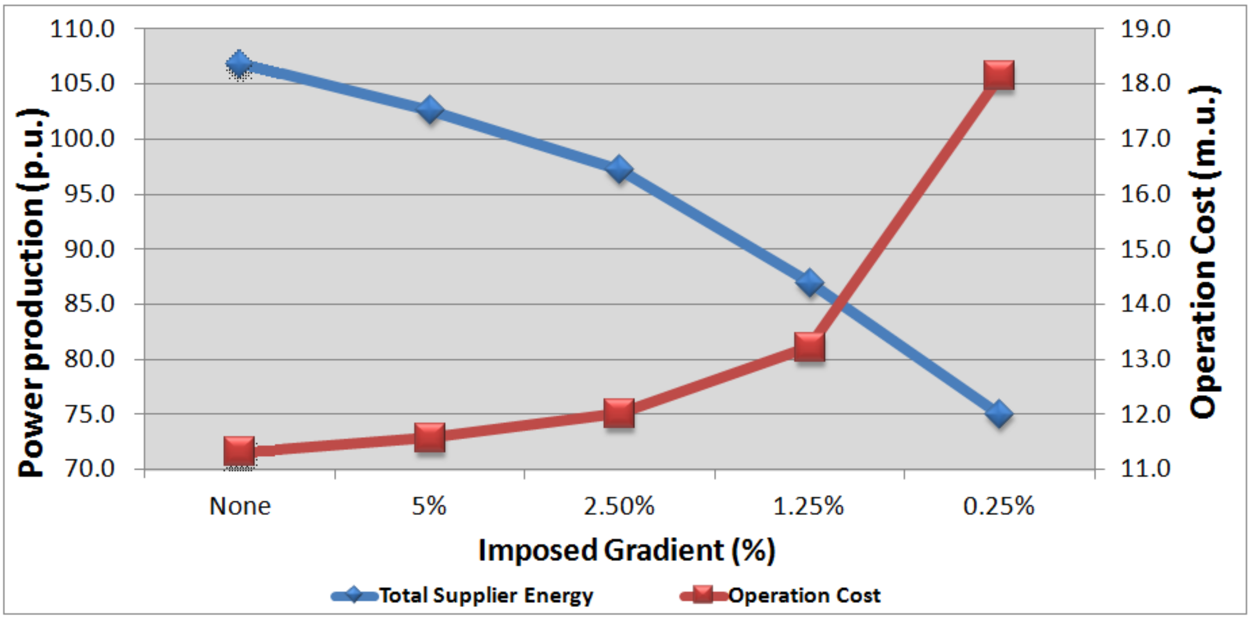

Figure 4.39 – Dispatched energy and operation cost for contract type 2.

The third type of contract imposes a minimum limit of remuneration for the whole 24 hours, i.e., it ensures a guaranteed minimum remuneration, regardless the energy produced in each hourly period.

In order to simulate the desired contract, it is necessary to amend the input data of the base case presented below. The simulation of the contract is divided into several simulations by parcels of the desired minimum remuneration. In this way, in the simulation it is imposed the minimum remuneration desired by percentage of the maximum possible remuneration.

The considered contract is established between a Fuel Cell unit and the VPP. This contract types imposes a minimum remuneration for the Fuel Cell unit throughout the time horizon. The minimum remuneration levels were determined for each Fuel Cell unit, according to its maximum generation capacity and the hourly energy price. The results are shown in Figure 4.40.

In Figure 4.40 it seems that with the gradual increase of the charge of minimum remuneration, there is a slight variation in the VPP operation cost. This happens due to the influence the capacity of power generation of Fuel Cell units has in the VPP resource management. In other words, the capacity of power generation of the Fuel Cell units is relatively small when compared to all the available resources in the network. The last two levels of imposed remuneration provide a growing increase in the VPP operation costs. However, the variation of the VPP operation costs between the minimum and maximum level of remuneration does not exceed 1.2%.

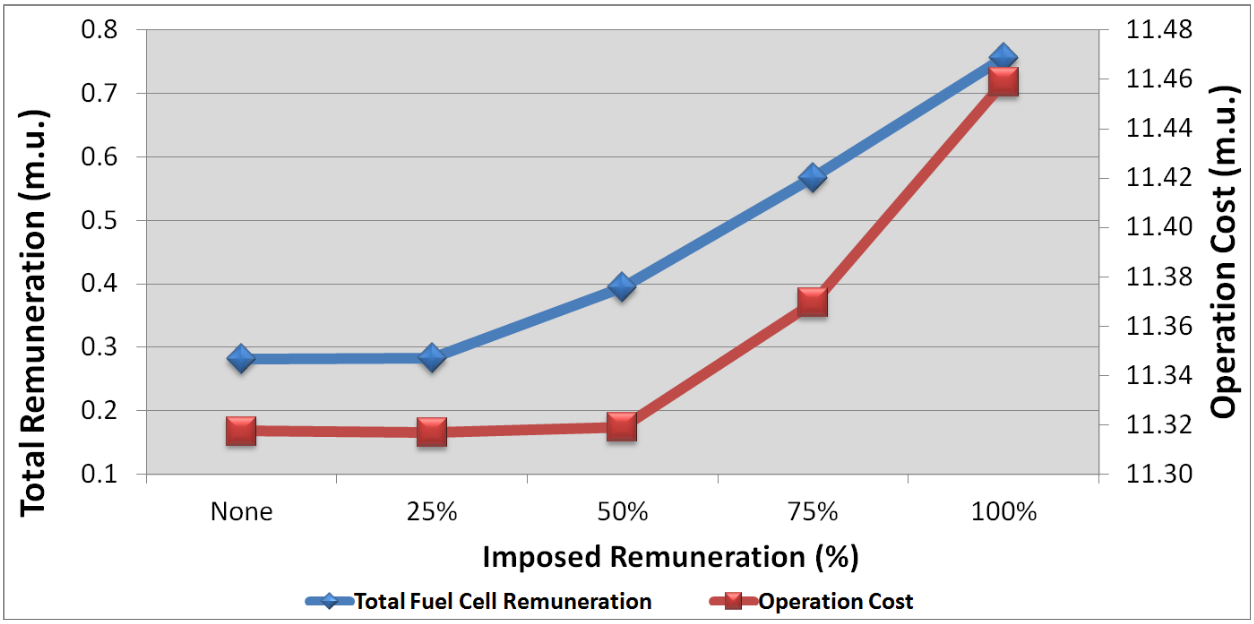

Figure 4.40 – Dispatched energy and operation costs for contract type 3.

The fourth type of contract establishes a minimum period of generation during the overall period of 24 hours. Producers with this type of contract are dispatched for a number of consecutive periods, thereby reducing start-up costs.

In order to simulate the proposed contract, the following changes of input data regarding the base case are considered. First, the energy price from the CHP technology generators has risen to 0.5 m.u./kWh. It is also considered that in period (t-1) the generators related to this contract were operational, i.e., the generators in the period prior to the period when the simulation started (t-1) is connected and it is supplying power to the network.

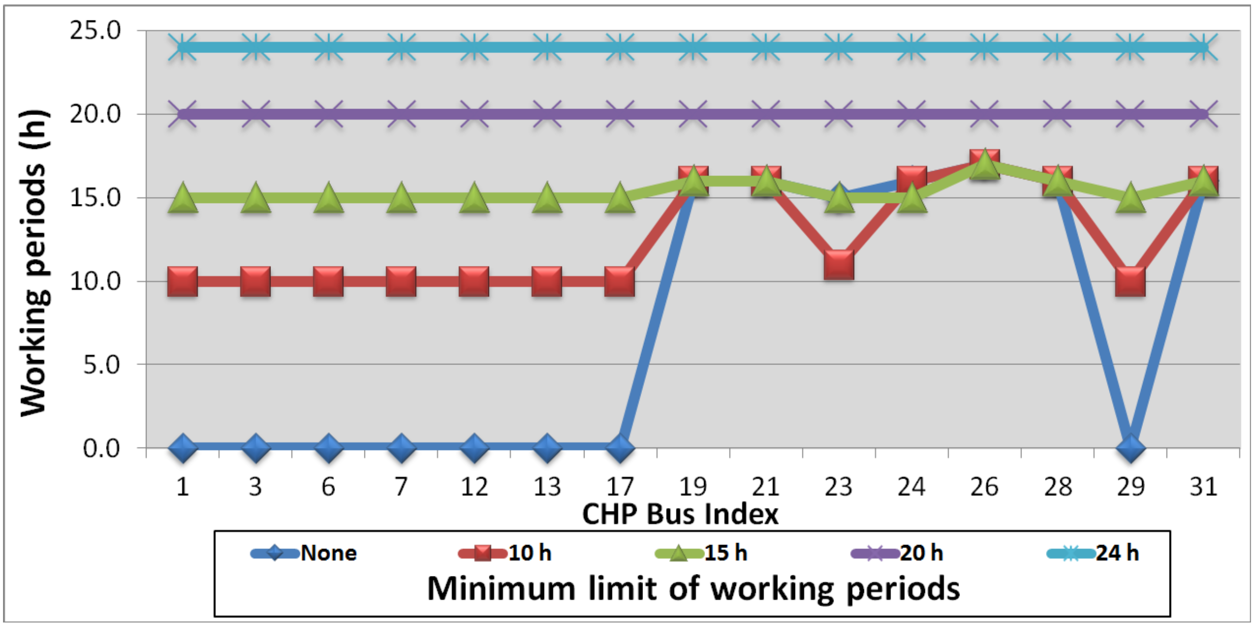

Figure 4.41 – Number of working periods for contract type 4.

Figure 4.41 and Figure 4.42 show the results of the simulations considering the CHP generators contracts that impose a minimum number of working periods. Generally, the CHP presents low generation costs, therefore most CHP units are dispatched during many time periods. If it is set an increase in the energy price generated by CHP, of course, the number of working periods decreases considerably. Setting a minimum number of working periods by scale illustrated in Figure 4.41, one can conclude that the CHP units related to the buses between 1 and 17 are considered more expensive generators, when compared to other neighbours resources of these CHP units.

In Figure 4.42 it is noticeable that the inclusion of this contract in the resource management is not expensive, because the increase in VPP operation costs with the total introduction of the contract (stipulating that all CHP generators participate in the market in the 24 periods) is less than 1.8% over the base case.

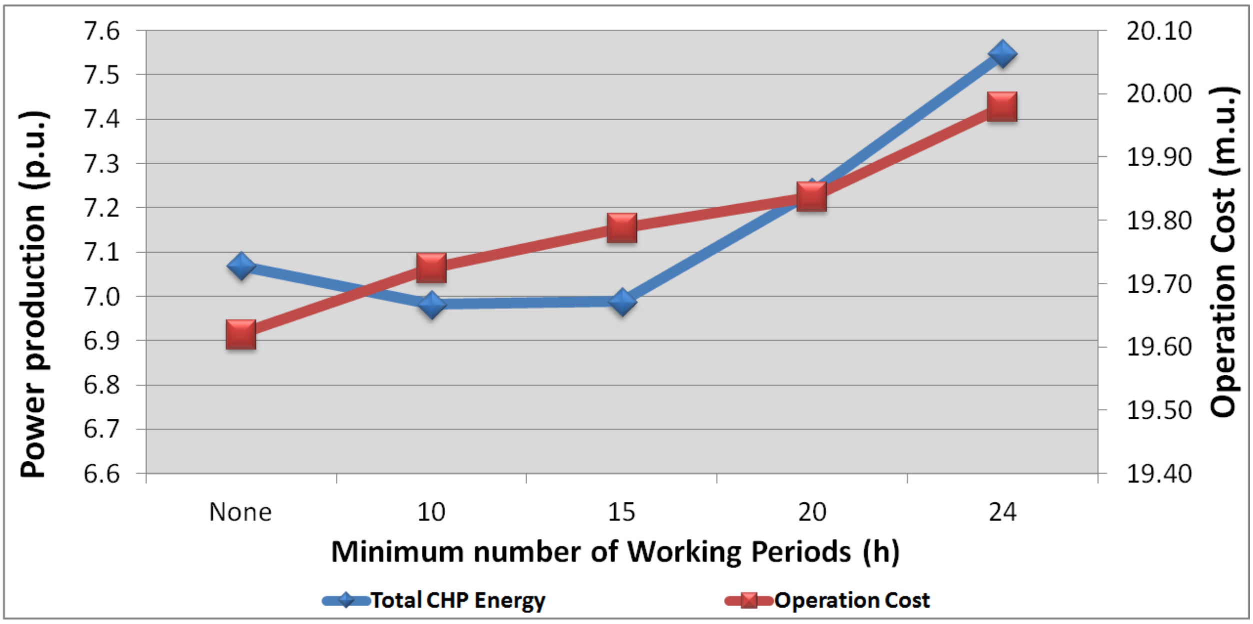

Figure 4.42 – Dispatched energy and operation cost for contact type 4.

This contract is particularly suited to certain distributed generation technologies, capable of generating a constant amount of energy over a time horizon of 24 hours. The CHP technology is tailored for this type of contract, because besides getting a constant production, this technology has a slow cold startup which does not allow its system operation to be in constant intermittency (on/off). Moreover, the system startup has a considerable cost in managing this system.

The fifth and final contract consists in a maximum number of entries in service throughout the 24 hours. In this context, the producer is forced to ensure stability from generation to avoid being excluded from the selection of production for the period established.

In order to a simulation of the contract be capable of reproducing results easily understood, some changes were made to the input data of the base case which influence the results of the problem. This type of contract imposes a maximum number of times that each generator enters in service. In this scenario it has been applied to the CHP generators. In this context, the energy price of all generating units related to the CHP technology increases to 0.4 m.u./kWh.

Figure 4.43 and Figure 4.44 show the obtained results. Figure 4.43 shows the number of service entrances of each CHP generator in accordance with the imposed limit.

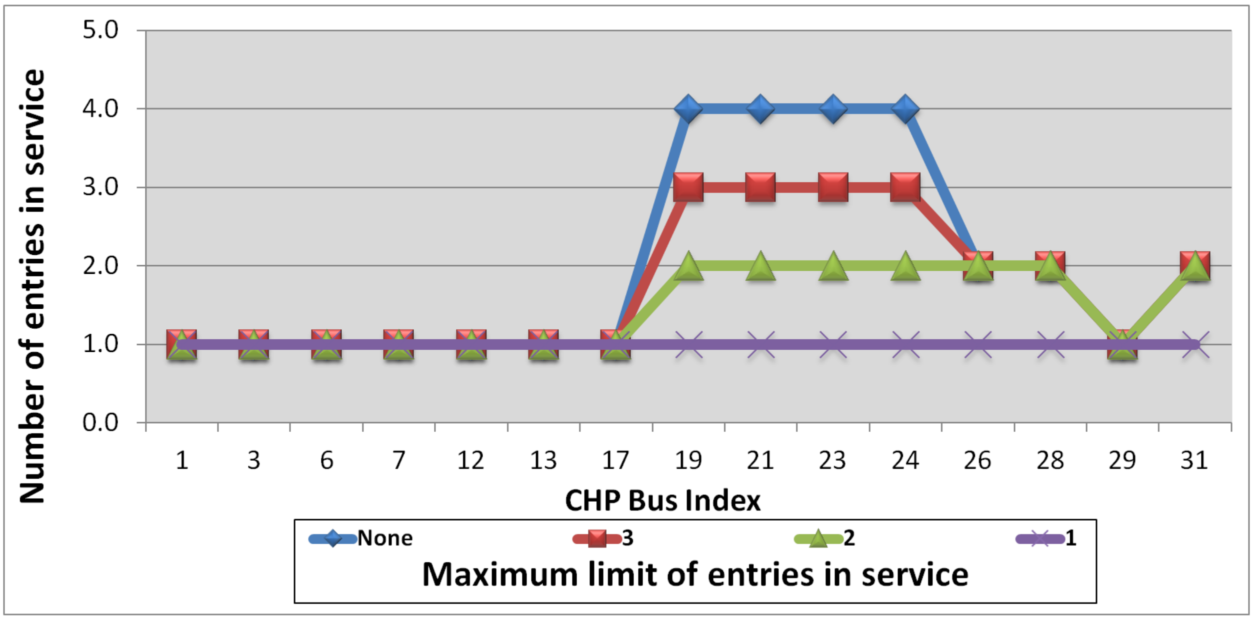

Figure 4.43 – Maximum number of entries into service.

Figure 4.44 shows the evolution of the total CHP generated energy and the VPP operation cost, regarding the established contracts.

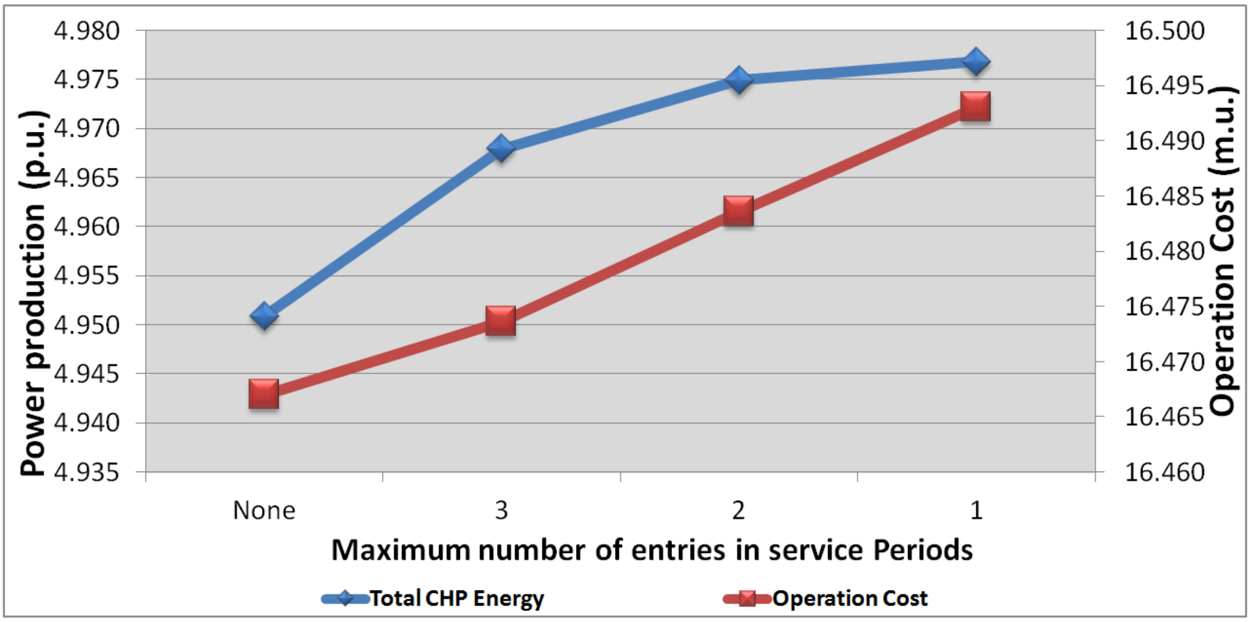

Figure 4.44 – Dispatched energy and operation cost for contract type 5.

Comparing the results of the base scenario (without contract – "None"), with the more rigid enforcement of this contract, the global energy dispatch of CHP generators increased about 0.16%, while the VPP operation costs increased about 0.52%.

Generally, the VPP can use this kind of contract to apply to CHP plants players, which also may want to set this kind of contract with the VPP in order to obtain generation stability, reducing the costs related to the system startup, and sometimes the need to work in the minimum load limit possible to maintain its system in a state of "readiness" to be ready to supply power at any time. Thus, this contract could be a feature or complement to other contracts.

4.6.3. Results analysis

The amount of distributed energy resources in power systems has increasing significantly in the past years. In the future, power systems will have to deal with large-scale integration of DG, types of DR and storage units. These resources can be crucial for the energy dispatch and for participation in ancillary services, in order to ensure the stability and security of supply requirements from the network and consumers.

In this context, the case study developed presents a perspective on the value and complexity of the proposed model. With this purpose, the case study was divided into five distinct parts, in which the complexity of each scenario gradually increases.

Firstly, it was developed a base scenario which considers the simulation of energy and ancillary service joint market implemented in a distribution network with extensive introduction of DER, using an AC optimal power flow. In this simulation, both the energy and ancillary services compete for power flow in the network. For this purpose, it has been used the Bialek topological factors method for solving this problem proposed in section 3.5. The method allows knowing the contribution of each generator in line congestion. Thus, it becomes possible to simulate which AS congestion causes in the network. In this way, it is known that the dispatch obtained for all services are feasible, implying that when AS are needed the prior dispatch is very close to reality, not requiring major readjustments, preventing a considerable increase in the operation costs of ancillary services for the VPP.

The second scenario includes all the features of the first scenario, with the biddings of the players in the market related to AS that can be made by network regions. The players from each region propose their bids in the market for different regions. The ability of the VPP of acting with mutual function of economical and technical management allows the VPP to manage the resources according to the rule, in which the generation units of each region should ensure the supply of at least 50% of the necessary requirement of the region in which they are located. This model allows the VPP prevent from potential congested lines in the border regions. The regions are established according to a forecast of possible congestion of an important supply zone, not causing energy not supplied, and also ensuring network stability.

The third scenario includes the use of DR resources participating in the AS dispatch. The types of DR (namely Cut and Reduce) can be an important resource in the network stability. However, the DR is typically used a few times in a year, as the goal of the system is to produce and to supply energy and not excessively to reduce the load [Walawalkar-2010]. In addition, this scenario includes the use of relaxation variables for each AS, and consequently for each region. This variable has the purpose of maintaining the network stability by lack or excess generation in each region. The presented model allows the generation units in regions with excess of generation (relaxation variable = 0) to participate in requirements in other regions. The VPP has to procure generation units which are capable of filling this variable without affecting network stability.

The fourth scenario considers the use of storage units in AS provision. The particular features of this kind of resources allow a greater management flexibility of energy and especially the ancillary services by the VPP. Due to the storage units' flexibility to charge and discharge along the time period, they can be used to store energy during low cost periods and discharge at peak periods. In this way, these resources can provide a good alternative for the diagram loads management compared to traditional resources. However, these resources have a greater impact in AS, because they are more expensive than traditional resources, thereby they do not regularly contribute to the energy service. Moreover, the energy storage capacity is limited, not having a large storage capacity. Thus, these resources are suited to the participation in the AS dispatch.

The fifth and final part of this case study includes all the features of the previous parts and introduces complex contracts between the VPP and players. The implemented methodology considers several types of complex contracts which enable players to impose relevant constraints when they establish contracts.

Complex contracts are very important to enable the aggregated players to achieve their goals. Although they make the energy resource management more complex, depending on the contract, its impact can be significant in the VPP operation costs. For the first contract types, the VPP operation costs increased about 20%; however, the last type of contract had an impact of about 1,2%. In this way, the VPP management should consider players' contracts which have clear and tangible objectives, beneficial for both parties.

In this case study, one can identify some advantages and disadvantages of the proposed methodology. Some of the clearest advantages of this methodology is the flexibility in adapting to several considerations which may arise in a energy and AS joint market, including: the possibility of splitting the AS procurement for regions of the network; the increasing importance of DR resources in the network management, and negotiating a good part of complex contracts existing in the market. However, the main advantage of this methodology and contribution from the common markets is the ability to dispatch all services (energy and ancillary services) in a hierarchical way without compromising the stability of the network and the technical constraints related to the network. This advantage was only possible through the implementation of topological Bialek factors based on proportional sharing methodology.

Regarding the disadvantages, it seems that the execution time of the method is slightly long, about 20 minutes of complete execution of the market. In this way, the methodology fits perfectly in the simulation of day-ahead market.

Briefly, it can be concluded that the proposed methodology is effective to solve the envisaged problem and to be implemented in MASCEM. This model proposes an energy and AS joint market simulation considering the possibilities of AS bidding regions, the large introduction of DER, complex contracts and especially the use of AC power flow using the topological Bialek factors, which allows the simulator to have greater flexibility and to control strategies from the standpoint of the VPP and players.

4.7. Conclusions

This subsection presents the main conclusions of the case studies related to the simulation of AS market models. The case studies presented were carefully selected in order to demonstrate the most relevant features regarding to the market models studied. In this context, the case studies cover a diversity of possible situations in a competitive environment, in both perspectives of the ISO/VPPs and the remaining players participating in the energy and AS joint market.

The first case study is the base model of the AS market simulation used in the development of the remaining models. In this case study, the results are shown regarding the simulation of the ancillary services (RD, RU, SP and NS) and the usefulness of the AS cascade system in the model. In this way, it is possible to verify that the simulation of the AS market, with the possibility of cascade process between services, may result in economic savings in the scope of the market optimization developed by the ISO. The last scenario of this case study shows the economic advantage of considering the AS market model with the possibility of ancillary services cascading. The economic savings presented in the scenario are about 16% compared to the simple simulation of the AS market in which the AS cascade is not considered.

The results of an energy and AS joint market model are presented in the second case study. In this case study, it is easy to verify the economic advantage to the ISO through the simultaneous and compact simulation of energy and AS market. The third scenario of this case study shows the comparison of results obtained through the simulation of separate market and joint market. In this scenario, it seems that the joint market simulation has an economic efficiency of about 4%, when comparing to the separate market for energy and AS market.

The third case study presents the comparison results of the proposed model in section 3.4 with a reference method proposed in [Wu-2004]. The model developed considers the joint market with the AS bids to be offered by regions of the network. The major differences between the developed model and the reference method is the use of an AC OPF capable of determining the active and reactive power flow in the network, instead of the DC model used in reference methodology. The LMP calculation of each node in the model developed considers the LMP of energy, system losses and network congestion, while in the reference method only considers the LPM of energy and network congestion. Furthermore, the possibility of AS cascade existing in the model developed is not considered in the reference model. In this way, the results of this case study show that the developed methodology introduces a clear approach to the reality of the power systems operation.

The fourth case study considers the electricity market model developed in section 3.5, based on the principle of Bialek topological factors methodology. In order to demonstrate the feasibility of the proposed methodology it was used a transmission network with 7 buses in this case study. The major advantage of the method is the demonstration of the feasibility by considering all services (energy and ancillary services) in the network congestion. The disadvantages are summarized by the execution time of the optimization process of the method, as well as the increased of operation costs for the ISO.

The last case study considers the innovative methodology developed in section 3.6 which uses the Bialek topological factors in order to obtain the feasibility of services dispatches included in the model, as well as the introduction of complex constraints related to the players/VPPs established contracts. The case study considers a distribution network of 33 buses and the use of DER, consisting mainly in DG (namely, photovoltaic, wind, CHP, Biomass, MSW, small hydro and Fuel Cell), DR and Storage units.

Firstly, this case study presents the results of joint market simulation which considers the use of an AC OPF and Bialek topological factors so that the solutions presented are feasible throughout the simulation process for each service. The energy dispatch shows that the DR has an important contribution in this schedule, about 12%, while the DG is about 29% and the storage unit has a minimal effect of about 1% in the dispatch.

After the energy dispatch, through the Bialek topological factors it is possible to determine the contribution that each resource has in the network flow. This contribution limits the resources for the remaining services according to the contribution which can still offer in view of the technical constraints of the network, at the level of congestion of network branches. This provides an optimization initially more expensive regarding the objective function value; however, this method ensures the feasibility of the dispatch for each service, thus benefiting a final anticipated dispatch in respect to the usual processes in real markets.

Regarding the use of DR resources to participate in the AS, they comprise a large part of the dispatch, and in some regions of the network they may reach 50% of the dispatch of an ancillary service to the respective region. This happens in cases when these resources are less expensive, or when the DG resources and external suppliers are limited to supply loads due to lines’ congestion.

The storage units’ participation in AS provision illustrates the versatility that this kind of resource can have when ensuring the balance and stability of power system. In this way, the obtained results show that the major purpose of the resources, from the VPP standpoint, involves the power systems stability. Thus, their participation emerges in periods of greater preponderance namely the periods between 20 and 22.

With regards to complex contracts, these are used to allow the VPPs establishing contracts with players in order to define beneficial conditions for both parties. In this case study, the VPP operating costs increased about 20%. However, this increase was not detected for all contracts established. In this way, the results of the last contracts studied in the case study have an impact of 1,2% in the VPP resource management.

All the simulations of the case studies presented in this chapter were developed in GAMS software using a deterministic approach, the Mixed-Integer Non-Linear Programming (MINLP). This technique ensures obtaining the global optimal in each optimization, which means that throughout the process simulation the best possible solution was always obtained. The execution time of most of the models presented in this work does not exceed 3 minutes of simulation. However, the methodology simulated in the last case study is quite complex, in which the dispatch of energy and each AS, considering AS bidding in different network regions, the introduction of all kind of resources in markets participation, as well as the use of complex contracts between players related to DG resources with the VPP, originate a quite long execution time of the sequential process of complete determination of this model, reaching 20 minutes of the total model simulation.

Chapter 5

Conclusions and Future Work

5. Conclusions and Future Work

This chapter presents the most significant conclusions of the work developed. It includes a critical analysis of the proposed methodology and the obtained results in order to highlight the objectives achieved and the contribution to the state of the art and, most importantly, to the future electricity market mechanisms. Furthermore, some perspectives related to future work are introduced.

5.1. Main conclusions and contributions

Ancillary Services (AS) are crucial to maintain and control the stability of power systems. Currently, and more in the future, AS markets will be influenced by a large set of different Distributed Energy Resources (DER). These new players can participate directly in the market or aggregated to some agents, such a Virtual Power Players. Due to the continuous increase of players with several kinds of DER, the development of new methodologies becomes necessary to provide flexible mechanisms to the energy and AS negotiation.

This dissertation focuses on the development and implementation of new market mechanisms for energy and AS, considering several players involved in the electricity market. A comprehensive work has been developed in order to address several objectives and different perspectives of AS management. In this way, the AS management from the Independent System Operator (ISO) and Virtual Power Player (VPP) standpoint were considered, taking into account the features of the players involved in each model.

The development of a model capable of simulating the joint market using a Alternate Current (AC) Optimal Power Flow (OPF) model for the simulation of technical constraints of the network; the introduction of an innovative method (Bialek topological factors) considering the ancillary services dispatch in the network congestion calculation, in order to prevent network congestion during the dispatch of all ancillary services considered in the market; and complex contracts implemented in order to enable the negotiation between players and VPPs, results in a complete and complex simulation model very close to current markets, as well as the main contribution of this dissertation.

The proposed models are based on California Independent System Operator (CAISO) market rules. CAISO is a nonprofit public entity subject to the FERC regulation, which operates the transmission facilities of all participants in power systems, and dispatches the generation units and the loads. The CAISO market includes several competitive and liberalized market mechanisms. An interesting market mechanism in the development of this dissertation is the energy and AS joint optimization. Therefore, in this work it was studied and adapted some of the innovative aspects of the CAISO market. The following CAISO rules were implemented and tested in joint energy and AS market:

- The use of relaxation variables in optimization problem, which always ensures obtaining results of the AS dispatch, regardless of the operation context;
- AS cascading mechanism;
- Energy and AS joint optimization;
- AS bidding by operation network regions.

All the models developed include the Regulation Down (RD), Regulation Up (RU), Spinning reserve (SP) and Non-Spinning Reserve (NS). The models also include several market mechanisms with different objectives for improving the market model. The relaxation variables are used to obtain an economic dispatch regardless of the operation context. Other mechanism is the AS cascading process, which is used to improve the economic efficiency of AS management.

The establishment of AS bids by network regions is a market mechanism used by the ISO in order to mitigate/avoid network congestion. For each region, part of the AS requirements (about 50%) is provided exclusively by internal energy resources of that region. The main advantage of this market mechanism is to decrease the probability of having network congestion in regions tendentiously problematic, as well as to improve the reliability and quality of the energy service. However, this mechanism does not ensure the technical and economical best solution.

The energy and AS joint market model do not ensure the solution feasibility. The main problem is that the model does not consider the impact that the AS may have on the network congestion. In order to solve this issue, an innovative methodology was developed to solve the network congestion caused by the simultaneous market clearing process of the joint market.

This methodology is based on Bialek topological distribution factors. The major contribution of this methodology is to always ensure a feasible solution of the energy and AS dispatch in any operation context. In what concerns the model runtime, it suits the ISO operation requirements. This methodology allows finding a better solution than the traditional methodology, guaranteeing the feasibility of the system, avoiding any network congestion that may occur in the traditional methodology.

The effectiveness of the proposed methodology is reflected in the results, since the operation costs are lower when compared with the traditional market methodology which needs further network congestion analysis to solve the congestion that the AS can cause in the network.

Other important contribution proposed in this dissertation is the inclusion of DER in AS such as Regulation Down, Regulation Up, Spinning and Non-Spinning reserve. In this way, an aggregator agent was proposed in order to manage and interact with a wide variety of DER, like Distribution Generation (DG) (mainly based on renewable energy sources), Demand Response (DR), and storage systems. The VPP is an agent that aggregates all kind of DER, and acts as network operator, providing AS to the system operator. The VPP has the ability to participate in the electricity market, taking into account the contracts established with the aggregated resources.

Based on these assumptions, a distribution network AS management methodology considering a large penetration of small players was developed. The methodology includes complex contracts between VPP and small players, so that the DER may participate in local AS management, as well as in AS market. The proposed contracts can consider features related to minimum limits of generation intended for the players, remuneration conditions, and the number of consecutive hours in generation, among others. The major advantage of this approach is the AS management by a VPP at the distribution network level with operation features related to the future of the power systems. On the other hand, the inclusion of DER allows easier on-site monitoring system stability. The establishment of complex contracts between the VPP and the players allows a careful and responsible management by power system entities.

The proposed methodology shows interesting results regarding the usefulness and ease of the DER participation in the AS procurement and dispatch. The results show that DER (especially storage systems) are indicated for the AS provision, due to their flexibility to participate in any AS addressed in the model. Furthermore, the results show that complex contracts cover a wide range of DER, providing greater capacity to the VPP to meet their internal needs and sell power in the market.

Several scenarios regarding the simulation of the developed AS models were implemented in each case study. These scenarios included several future power systems characteristics, such as the intensive use of DG, DR and storage resources, the consideration of the ISO/VPP management in liberalized environment, among other characteristics. The set of case studies included in this dissertation illustrates the use of the proposed methodologies, and demonstrates the applicability and advantages of the proposed models.

The analysis conducted from the ISOs and VPPs standpoints are included in the presented set of case studies. The submission of AS bids by regions of the network, especially by storage systems, is also presented. In this case, the use and usefulness of the ability of storage units to charge and discharge for each ancillary service type is illustrated. Moreover, a set of complex contracts between DER and VPP are illustrated.

All the models simulated were developed using the General Algebraic Modeling System (GAMS) optimization tool, based on the model of deterministic optimization approach (Mixed-Integer Non-Linear Programming – MINLP). Based on this technique, the more complex model proposed in the development of this work reached 20 minutes of simulation. In this way, the proposed model fits the Day-Ahead Market (DAM) simulation.

Lastly, all the methodologies proposed and implemented were included in the Multi-Agent Simulator of Competitive Electricity Markets (MASCEM). MASCEM is a simulator which depicts the study of complex restructured electricity markets operation. In this way, the methodologies developed in this dissertation provide additional methodological bases to MASCEM, for the simulation of the present and future operation of the energy and AS market.

5.2. Perspectives for future work

Throughout the development of this work, several ideas have arisen to potentially proceed with the evolution of the present work. Some of the envisaged concepts are closely connected to new FCT projects which were recently initiated, namely the following projects:

- IMaDER – Intelligent Short Term Management of Distributed Energy Resources in a Multi-Player Competitive Environment (PTDC/SEN-ENR/122174/2010);
- MAN-REM – Multi-Agent Negotiation and Risk Management in Electricity Markets (PTDC/EEA-EEI/122988/2010).

Among the many advances that the development of this work gave opportunity to, allowing future works and scientific findings, some future developments can be referred:

- Improvement of AS optimization methodologies considering the several levels of AS management (ISO, TSO, DSO and VPP);
- Introduction of all kind of DER in the market or in the VPP, mainly consisting of DG technologies, Electric Vehicles (EV), types of DR considering different kind of consumers (Large and medium Industrial, Large, medium and small Commerce, and Domestic consumer) and storage units;
- Enable players to submit more complex bids, taking into account in the dispatch process, the constraints related to startup costs of some technologies, minimal load costs regarding the state of readiness of a generator to enter in service at a certain time to fill a gap of generation, and generation ramps related to features of each AS;
- Develop and implement a AS management tool where it is possible to identify and evaluate the risk of the bids that a VPP can run in the market;
- The ability of the tool has appropriate methodologies of learning the knowledge of the market in which the VPP operates.

The suggestions for improving the energy and AS market simulation, indicated as future work, are part of the objectives to continuously improve MASCEM simulator, with the objective of providing the users of the simulator with a wide range of simulation tools which can be adapted to the different characteristics of each market, as well as the consideration of new trends that might arise in the competitive market environment.

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Annexes

Annex A

Data from the Case Study – AS model

Table A.1 shows the input data for the first scenario of the case study in section 4.2. In this table arise features concerning the quantities and prices of each AS that each player offers to the market, as well as the requirements of each AS imposed by the SO.

Table A.1 – Input data for scenario 1 of AS model.

Regulation Down			Regulation Up			Spinning Reserve			Non-Spinning Reserve			Maximum Capacity (MW)	Minimum Requirement (MW)	Maximum Requirement (MW)
Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u/MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)			
70	85	10.0	80	85	5.0	80	85	10.5	95	98	10.0	280	150	500
80	85	8.0	70	85	4.5	70	85	9.2	45	60	11.0	250	200	200
55	85	8.0	80	85	5.2	80	85	8.5	70	70	10.2	290	150	150
60	85	4.0	50	85	5.0	50	85	8.3	41	60	10.6	250	150	150
100	111	3.5	65	85	6.3	65	85	8.9	45	60	9.0	255		
20	85	9.0	50	85	6.0	50	85	8.8	18	60	11.0	245		
40	85	7.0	98	99	7.5	98	99	9.3	24	60	10.5	265		
10	85	4.8	100	120	6.5	100	120	8.6	80	81	10.4	330		
40	85	9.0	110	130	5.5	110	111	8.3	80	81	10.3	350		
15	85	10.0	40	85	4.0	40	85	8.0	90	91	9.0	280		

Table A.2 shows the input data used in the case study of section 4.2 for the second scenario.

Table A.2 – Input data for scenario 2 of AS model.

Regulation Down			Regulation Up			Spinning Reserve			Non-Spinning Reserve			Maximum Capacity (MW)	Minimum Requirement (MW)	Maximum Requirement (MW)
Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u/MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)			
70	85	10.0	40	85	15.0	80	85	5.0	10	30	7.0	100	100	500
80	85	8.0	30	85	10.0	70	85	9.0	11	25	4.0	110	200	200
55	85	8.0	40	85	8.2	80	85	8.5	12	30	6.0	115	50	50
60	85	4.0	30	85	5.0	60	85	7.2	13	36	4.6	112	400	450
100	111	3.5	35	85	7.0	65	85	4.0	9	15	9.0	113		
20	85	9.0	20	85	14.6	55	85	8.0	9	19	11.0	103		
40	85	7.0	50	99	8.5	98	99	7.3	9	20	10.5	205		
10	85	4.8	40	120	10.6	100	120	6.6	24	62	4.0	209		
40	85	9.0	10	130	6.5	110	111	4.3	21	35	5.3	302		
15	85	10.0	40	85	4.0	55	85	9.0	36	60	5.0	350		

Table A.3 shows the input data used in the case study of section 4.2 for the third scenario.

Table A.3 – Input data for scenario 3 of AS model.

Regulation Down			Regulation Up			Spinning Reserve			Non-Spinning Reserve			Maximum Capacity (MW)	Minimum Requirement (MW)	Maximum Requirement (MW)
Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)	Minimum quantity (MW)	Maximum quantity (MW)	Bid price (m.u./MWh)			
70	85	10.0	80	85	5.0	80	85	10.5	95	98	10.0	280	150	500
80	85	8.0	70	85	4.5	70	85	9.2	45	60	11.0	250	200	400
55	85	8.0	80	85	5.2	80	85	8.5	70	70	10.2	290	150	200
60	85	4.0	50	85	5.0	50	85	8.3	41	60	10.6	250	150	200
100	111	3.5	65	85	6.3	65	85	8.9	45	60	9.0	255		
20	85	9.0	50	85	6.0	50	85	8.8	18	60	11.0	245		
40	85	7.0	98	99	7.5	98	99	9.3	24	60	10.5	265		
10	85	4.8	100	120	6.5	100	120	8.6	80	81	10.4	330		
40	85	9.0	110	130	5.5	110	111	8.3	80	81	10.3	350		
15	85	10.0	40	85	4.0	40	85	8.0	90	91	9.0	280		

Annex B

Data from the Case Study – Energy and AS joint market model

Table B.1 shows the input data necessary for the case study of the section 3.3.

Table B.1 – Energy and AS joint market data.

Energy and Ancillary Services Joint Market														
Bids	Regulation Down		Regulation Up		Spin Reserve		Non-Spin Reserve		Energy		Max Power (MW)	Loads	
	Qt (MW)	Pe (m.u./MWh)	Qt (MW)	Pe (m.u./MWh)	Qt (MW)	Pe (m.u./MWh)	Qt (MW)	Pe (m.u./MWh)	Qt (MW)	Pe (m.u./MWh)		Qt (MW)	Pe (m.u./MWh)
1	70	10	80	15	10	5	95	7	430	2.1	450	300	7
2	80	8	70	8.1	55	9	45	4	350	3.6	400	100	5
3	55	8	80	7.1	88	8.5	70	6	480	5.2	500	80	4.1
4	60	4	50	5	30	7.2	41	4.6	450	5.8	480	300	7.7
5	100	3.5	65	7	24	4	45	9	250	6.3	300	350	8.8
6	20	9	50	14.6	80	8	18	11	270	3.5	280	350	9.9
7	40	7	98	7.2	50	7.3	24	4	299	2.8	320	105	4.5
8	10	4.8	100	8.3	60	6.6	80	10.5	399	9.2	405	80	3.9
9	40	9	100	6.5	10	4.3	80	5.3	345	4.5	400	300	7.5
10	15	10	40	4	49	9	90	5	369	3.9	400	100	5.5
Req	Min	Max	Min	Max	Min	Max	Min	Max	Forecastes Losses		-	Rigid Demand	
	250	300	200	300	150	200	150	200	160			1300	

Table B.2 shows the AS dispatch without AS cascade, as well as the market price associated to each AS and their cost to the SO.

Table B.2 – AS market results in scenario 1 of joint model.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	0	15.0	10	5.0	10	7.0	20
2	0	8.0	0	8.1	5	9.0	45	4.0	50
3	40	8.0	0	7.1	20	8.5	0	6.0	20
4	60	4.0	4	5.0	11	7.2	15	4.6	30
5	100	3.5	65	7.0	24	4.0	14	9.0	103
6	0	9.0	0	14.6	10	8.0	0	11.0	10
7	40	7.0	0	7.2	0	7.3	21	4.0	21
8	10	4.8	100	8.3	60	6.6	0	10.5	160
9	0	9.0	0	6.5	10	4.3	45	5.3	55
10	0	10.0	31	4.0	0	9.0	0	5.0	31
Contracted Service (MW)	250		200		150		150		750
Market Clearing Price (m.u./MWh)	8.0		8.3		9.0		9.0		Total (m.u.)
Total Cost (m.u.)	2000		1660		1350		1350		6360

Table B.3 Shows the AS dispatch with AS cascade, and moreover shows the market clearing price of each AS, and the cost associated with each ancillary service, and the overall cost to the SO.

Table B.3 – AS market results with cascading mechanism in scenario 1 of joint model.

Bids	Regulation Down		Regulation Up		Spinning Reserve		Non-Spinning Reserve		Total (MW)
	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	MW	m.u./MWh	
1	0	10.0	0	15.0	10	5.0	10	7.0	20
2	0	8.0	5	8.1	0	9.0	45	4.0	50
3	40	8.0	5	7.1	0	8.5	15	6.0	20
4	60	4.0	30	5.0	0	7.2	0	4.6	30
5	100	3.5	65	7.0	24	4.0	14	9.0	103
6	0	9.0	0	14.6	10	8.0	0	11.0	10
7	40	7.0	0	7.2	0	7.3	21	4.0	21
8	10	4.8	100	8.3	60	6.6	0	10.5	160
9	0	9.0	0	6.5	10	4.3	45	5.3	55
10	0	10.0	31	4.0	0	9.0	0	5.0	31
Contracted Service (MW)	250		236		114		150		750
Slacks	-		RU to SP		SP to NS		-		
			36	8.3	0	9.0			
			RU to NS		-				
			0	8.3					
Service Used (MW)	250		200		150		150		650
Market Clearing Price (m.u./MWh)	8.0		8.3		8.0		9.0		Total (m.u.)
Total Cost (m.u.)	2000		1958.8		912		1350		6220.8

Annex C

Data from the Case Study – Joint Market model applied by VPP

Table C.1 shows the resistance, inductive reactance, capacitive susceptance and the thermal limit.

Table C.1 – Branch data of the 33-bus distribution network.

Branch number	Bus Out	Bus In	R (Ohm)	X_L (Ohm)	B_C (Siemens)	Thermal limit (MVA)
1	0	1	0.1332	0.0471	0	4.5
2	1	2	0.7122	0.2517	0	4.5
3	1	18	0.2699	0.0954	0	4.5
4	2	3	0.3890	0.1048	0	3.29
5	2	22	0.6039	0.2134	0	4.5
6	3	4	0.1911	0.0515	0	3.29
7	4	5	0.7262	0.1957	0	3.29
8	5	6	1.0514	0.2833	0	3.29
9	5	25	1.0656	0.2872	0	3.29
10	6	7	0.2007	0.0541	0	3.29
11	7	8	0.3822	0.1030	0	3.29
12	8	9	1.4984	0.4038	0	3.29
13	9	10	0.5528	0.1488	0	3.29
14	10	11	0.6033	0.1626	0	3.29
15	11	12	0.7618	0.2053	0	2.29
16	12	13	1.3157	0.3546	0	3.29
17	13	14	0.7472	0.2014	0	3.29
18	14	15	0.3280	0.0884	0	3.29
19	15	16	3.0084	0.8107	0	3.29
20	16	17	0.8190	0.2207	0	3.29
21	18	19	1.0241	0.3620	0	4.5
22	19	20	0.6518	0.2304	0	4.5
23	20	21	1.2973	0.4585	0	4.5
24	22	23	1.2944	0.4575	0	4.5
25	23	24	0.1497	0.0529	0	4.5
26	25	26	0.2901	0.0782	0	3.29
27	26	27	1.0810	0.2913	0	329
28	27	28	0.8209	0.2212	0	3.29
29	28	29	0.5180	0.1396	0	3.29
30	29	30	0.9946	0.2680	0	3.29
31	30	31	0.3169	0.0854	0	3.29
32	31	32	0.3481	0.0938	0	3.29

Table C.2 shows information regarding DG and external supplier's resources to energy service to be used as input data base for the case studies discussed.

Table C.2 – Distributed generation and external suppliers resources bids features.

Type of generator	Number of units	Total installed power (kW)	Energy price (m.u./kWh)		
			Minimum	Mean	Maximum
Photovoltaic	32	528	0.08	0.1398	0.254
Wind	5	490	0.05	0.0652	0.08
Hydro	2	70	0.032	0.0432	0.049
Biomass	3	350	0.06	0.2653	0.65
MSW	1	10	0.03	0.0484	0.056
CHP	15	1,240	0.0001062	0.0179	0.065
Fuel Cell	8	235	0.095	0.1021	0.11
Total of DG	66	2,923	-	-	-
External suppliers	1	15,000	0.015	0.0434	0.07
Total	67	17,923	-	-	-

The input data relating to AS bids (Regulation Down and Regulation Up) are shown in Table C.3.

Table C.3 – DG and external suppliers bids for RD and RU services.

Type of generator	Regulation Down price (m.u./kWh)			Regulation Up (m.u./kWh)		
	Minimum	Mean	Maximum	Minimum	Mean	Maximum
Photovoltaic	0.088	0.15378	0.2794	0.088	0.15378	0.2794
Wind	0.055	0.07172	0.088	0.055	0.07172	0.088
Hydro	0.0352	0.04752	0.0539	0.0352	0.04752	0.0539
Biomass	0.066	0.29183	0.715	0.066	0.29183	0.715
MSW	0.033	0.05324	0.0616	0.033	0.05324	0.0616
CHP	0.000117	0.01969	0.0715	0.000117	0.01969	0.0715
Fuel Cell	0.1045	0.11231	0.121	0.1045	0.11231	0.121
External suppliers	0.0165	0.04774	0.077	0.0165	0.04774	0.077

The input data relating to AS bids (Spinning Reserve and Non-Spinning Reserve) are shown in Table C.4.

Table C.4 – DG and external suppliers bids for SP and NS service.

Type of generator	Spinning Reserve price (m.u./kWh)			Non-Spinning Reserve price (m.u./kWh)		
	Minimum	Mean	Maximum	Minimum	Mean	Maximum
Photovoltaic	0.096	0.16776	0.3048	0.1	0.17475	0.3175
Wind	0.06	0.07824	0.096	0.0625	0.0815	0.1
Hydro	0.0384	0.05184	0.0588	0.04	0.054	0.06125
Biomass	0.072	0.31836	0.78	0.075	0.331625	0.8125
MSW	0.036	0.05808	0.0672	0.0375	0.0605	0.07
CHP	0.000127	0.02148	0.078	0.000133	0.022375	0.08125
Fuel Cell	0.114	0.12252	0.132	0.11875	0.127625	0.1375
External suppliers	0.018	0.05208	0.084	0.01875	0.05425	0.0875

Table C.5 shows the input data of DR bids for energy service.

Table C.5 – Demand response bids for energy service.

	Reduce (kW)			Cut (kW)		
	Minimum	Mean	Maximum	Minimum	Mean	Maximum
DR	0.0071	0.0222	0.2502	0.0071	0.0181	0.1475
	Reduce (m.u./kWh)			Cut (m.u./kWh)		
	Minimum	Mean	Maximum	Minimum	Mean	Maximum
	0.1	0.1312	0.8	0.09	0.223	1.2

Table C.6 shows the storage units features.

Table C.6 – Storage features.

Storage features	Initial state (kWh)	Charge Capacity (kWh)	Discharge Capacity (kWh)	Maximum Capacity (kW)	Price charge (m.u./kWh)	Price Discharge (m.u./kWh)
Minimum	0.03	0.8	0.4	0.1	0.4	0.45
Mean	0.056	0.8	0.4	0.1	0.475	0.525
Maximum	0.08	0.8	0.4	0.1	0.55	0.6

Table C.7 illustrates the charge and discharge prices used by storage units for all ancillary services.

Table C.7 – AS charge and discharge storage prices.

AS Storage features		Minimum	Mean	Maximum
Price charge (m.u./kWh)	Regulation Down	0.04	0.0475	0.055
	Regulation Up	0.02	0.0238	0.0275
	Spinning Reserve	0.028	0.0333	0.0385
	Non-Spinning Reserve	0.02	0.0238	0.0275
Price Discharge (m.u./kWh)	Regulation Down	0.045	0.0525	0.06
	Regulation Up	0.0225	0.0263	0.03
	Spinning Reserve	0.0315	0.0368	0.042
	Non-Spinning Reserve	0.0225	0.0263	0.03

Figure C.1 shows the percentage of power given by each kind of resource for energy dispatch.

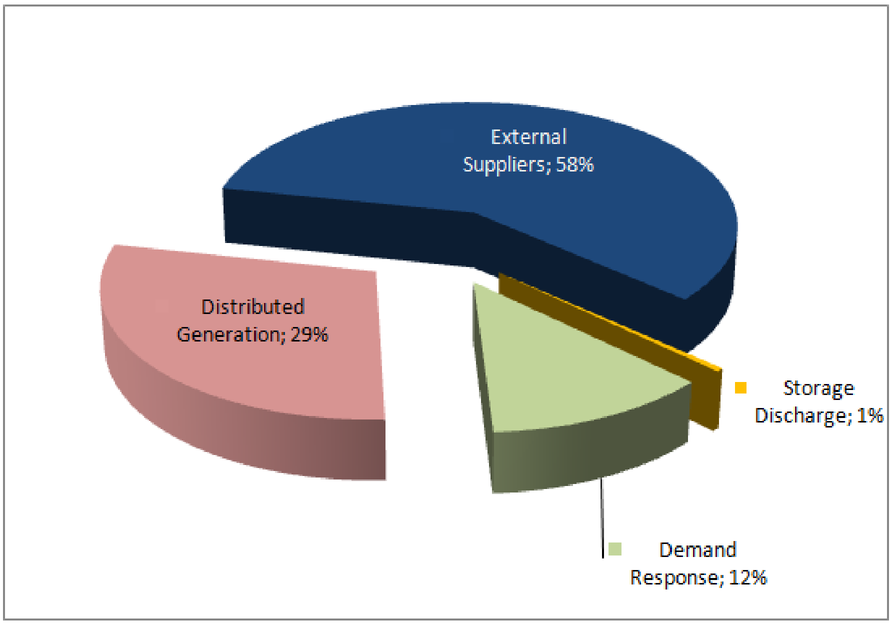

Figure C.1 – Percentage of power given by each kind of resource for energy dispatch, in scenario 1 of joint market model applied by VPP.

The percentage contribution of each DG technology has on energy dispatch is given by Figure C.2.

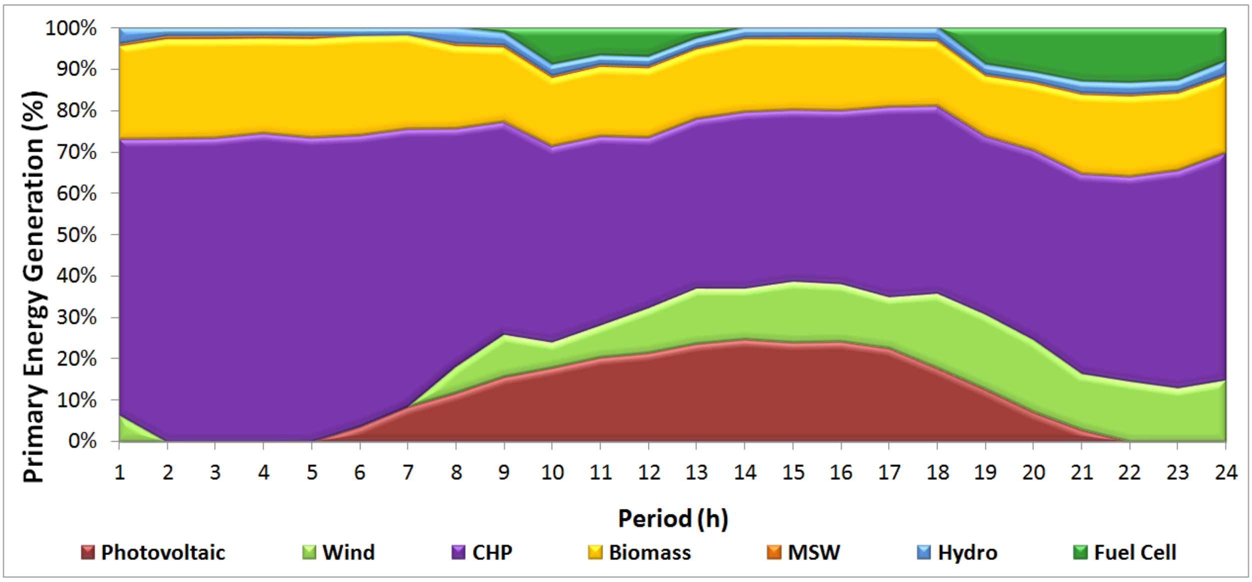

Figure C.2 – Percentage of DG contribution for energy dispatch, in scenario 1 of joint market model applied by VPP.

Figure C.3 shows the contribution of type of DR in energy dispatch.

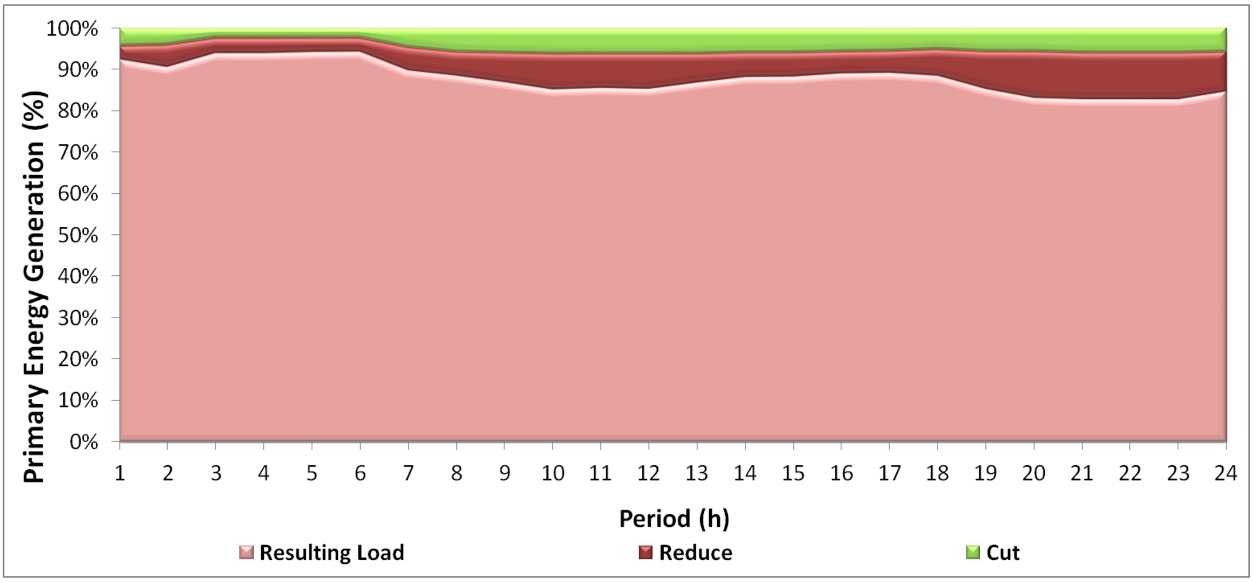

Figure C.3 – Type of DR contribution in energy dispatch, in scenario 1 of joint market model applied by VPP.

Figure C.4 shows the percentage of power given by each kind of resource for ancillary services dispatch.

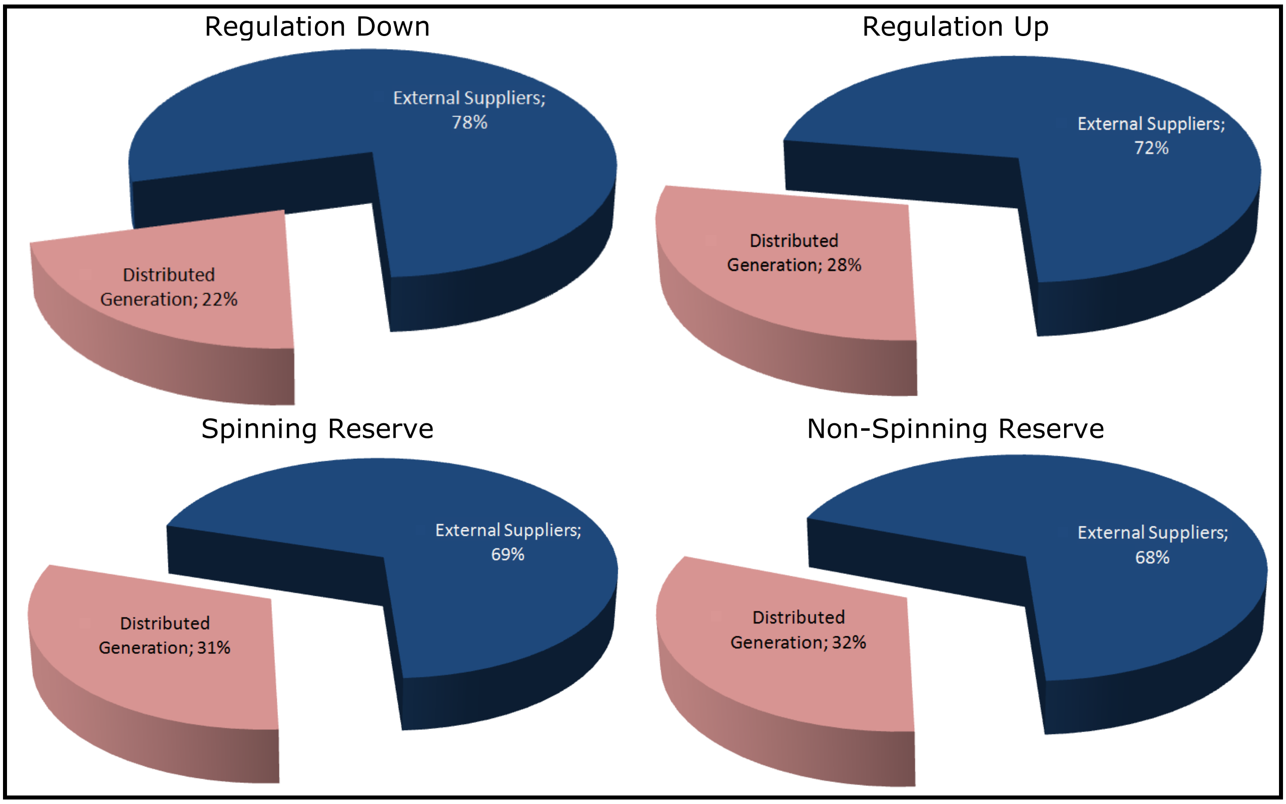

Figure C.4 – Resource contribution for RD, RU, SP and NS dispatch, in scenario 1 of joint market model applied by VPP.

Figure C.5 shows the percentage of power given by each kind of resource for energy dispatch for scenario presented in section 4.6.2.2.

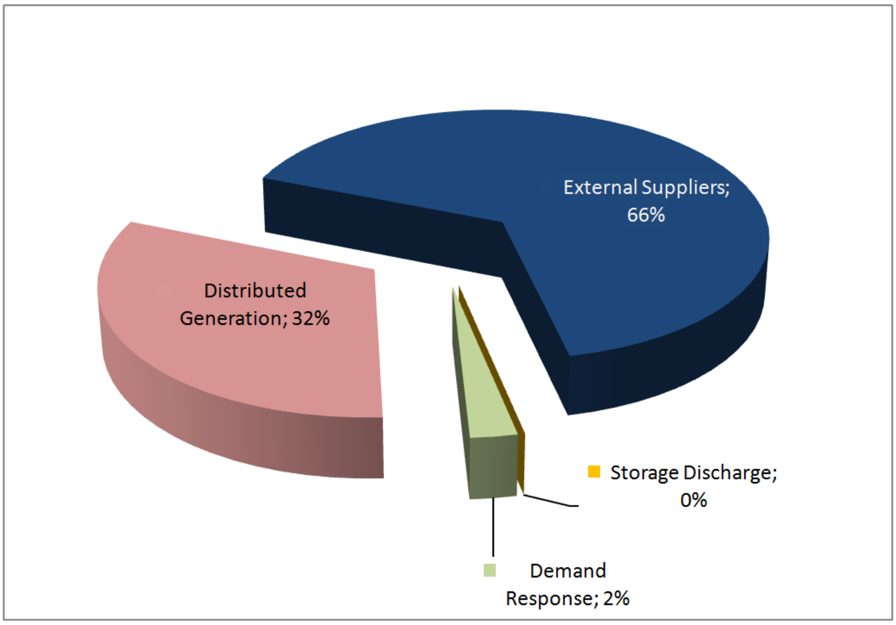

Figure C.5 – Resource contribution for energy dispatch, in scenario 2 of joint market model applied by VPP.

The contribution that each type of DG technology has in energy dispatch is given by Figure C.6.

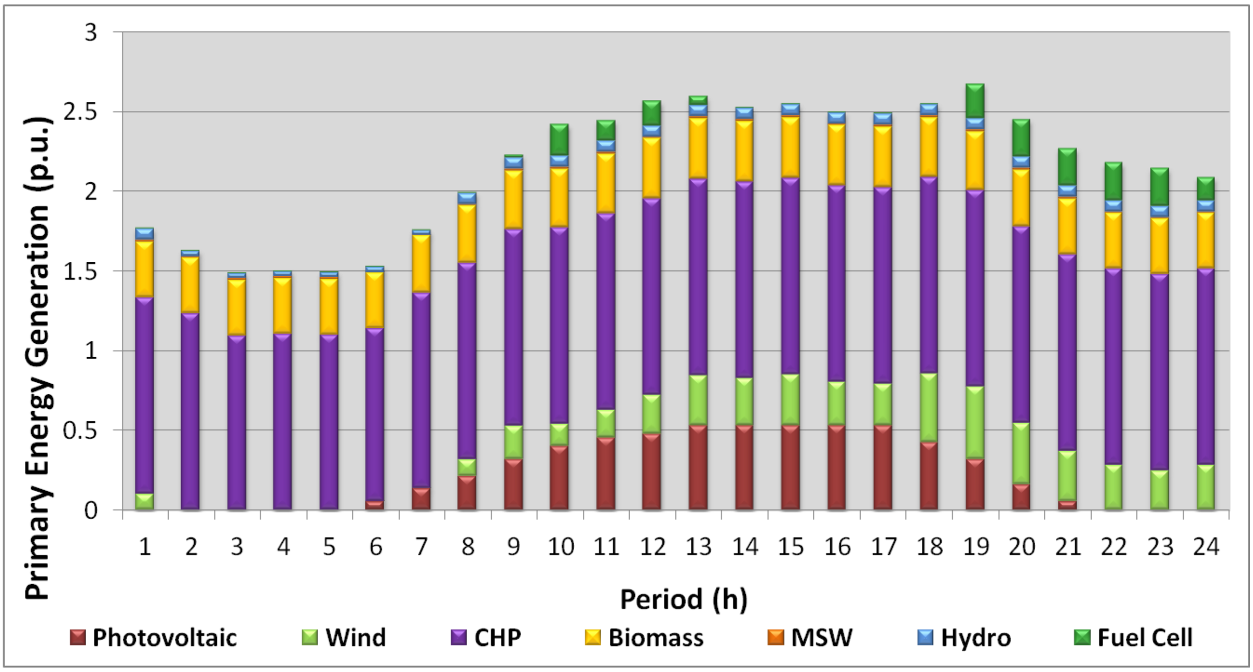

Figure C.6 – Energy dispatch by DG technologies contribution, in scenario 2 of joint market model applied by VPP.

Figure C.7 reflects the percentage of DG production in energy dispatch.

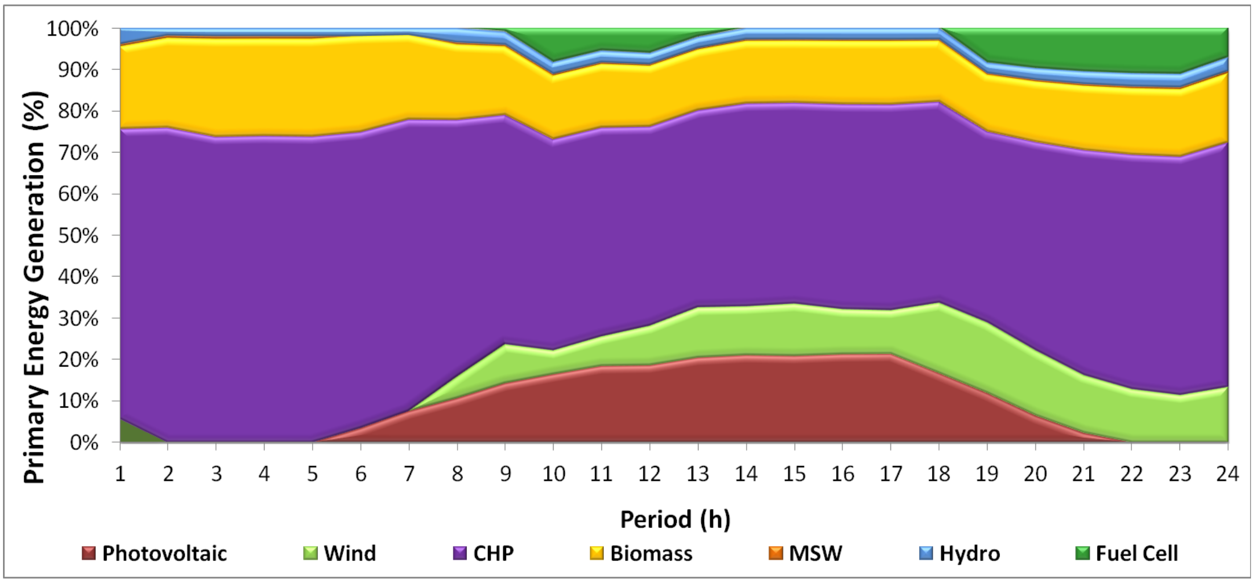

Figure C.7 – Percentage of DG contribution for energy dispatch, in scenario 2 of joint market model applied by VPP.

Figure C.8 illustrates the sharing of each type of DR on energy dispatch as well as the load really dispatched.

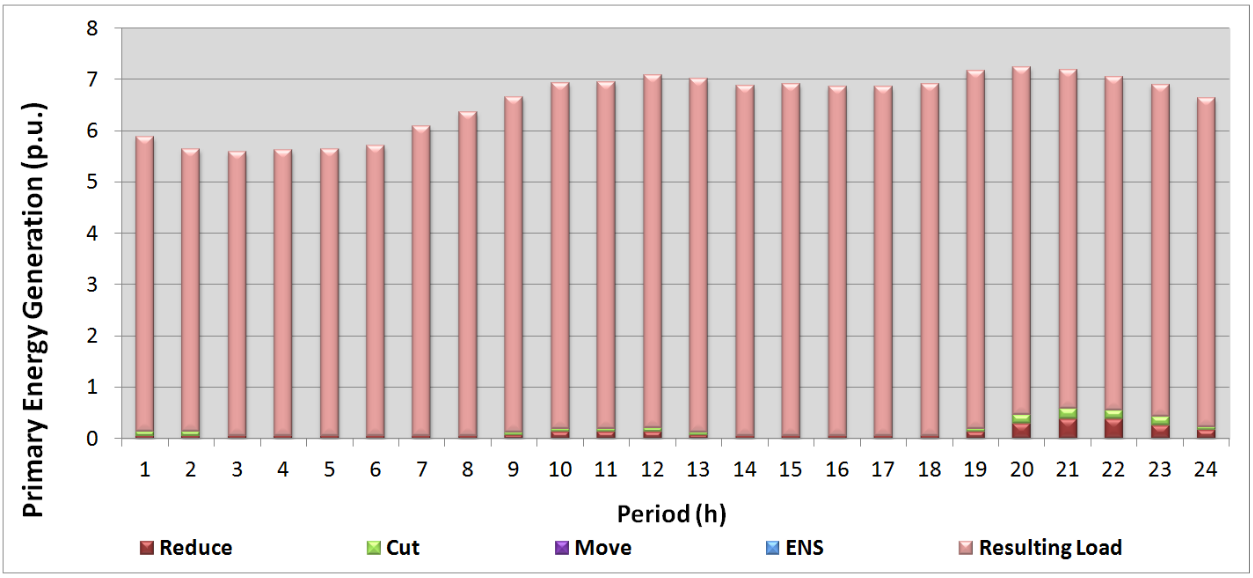

Figure C.8 – Type of DR for energy dispatch, in scenario 2 of joint market model applied by VPP.

The percentage of importance which DR resource has in energy dispatch is given by Figure C.9.

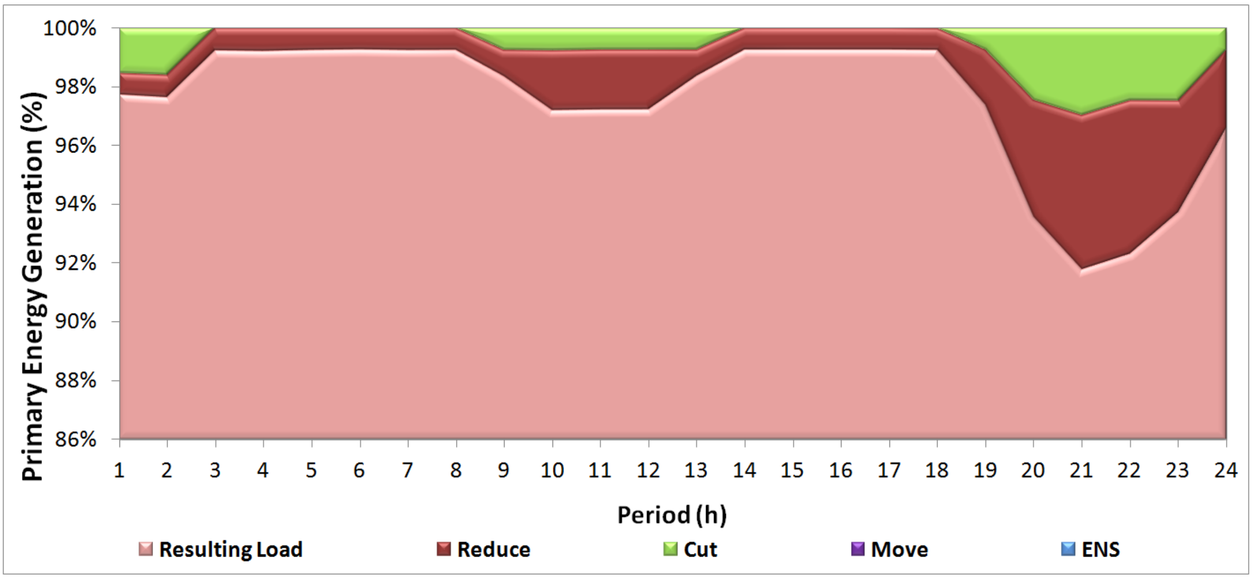

Figure C.9 – Percentage of DR contribution for energy dispatch, in scenario 2 of joint market model applied by VPP.

Figure C.10 shown the Regulation down dispatch considering different bidding regions.

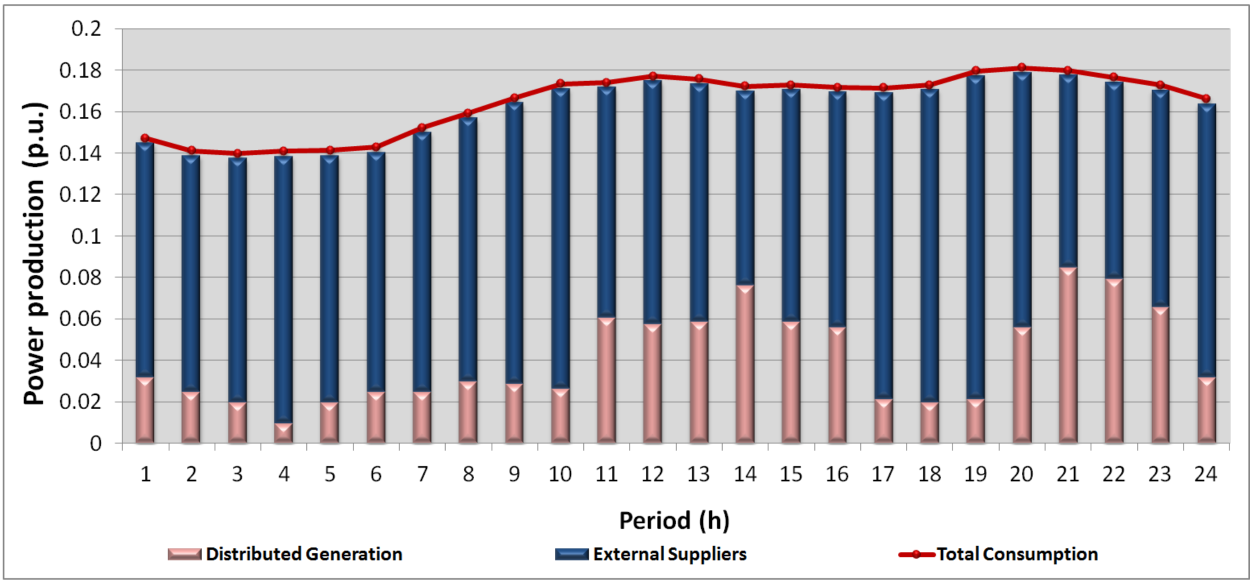

Figure C.10 - Regulation down dispatch, in scenario 2 of joint market model applied by VPP.

Figure C.11 shows the dispatch of the generators and external suppliers to Regulation Up reserve, without differentiating the region which generation corresponds.

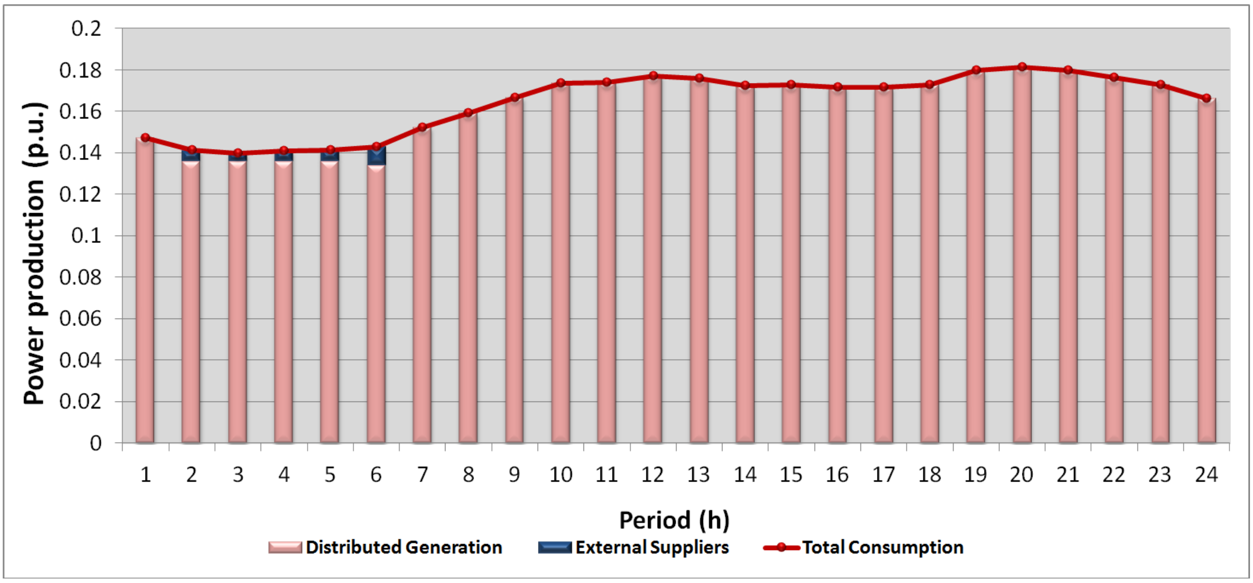

Figure C.11 – DG and external supplier dispatch for regulation up service, in scenario 2 of joint market model applied by VPP.

Figure C.12 shows the dispatch of the generators and external suppliers to Spinning Reserve.

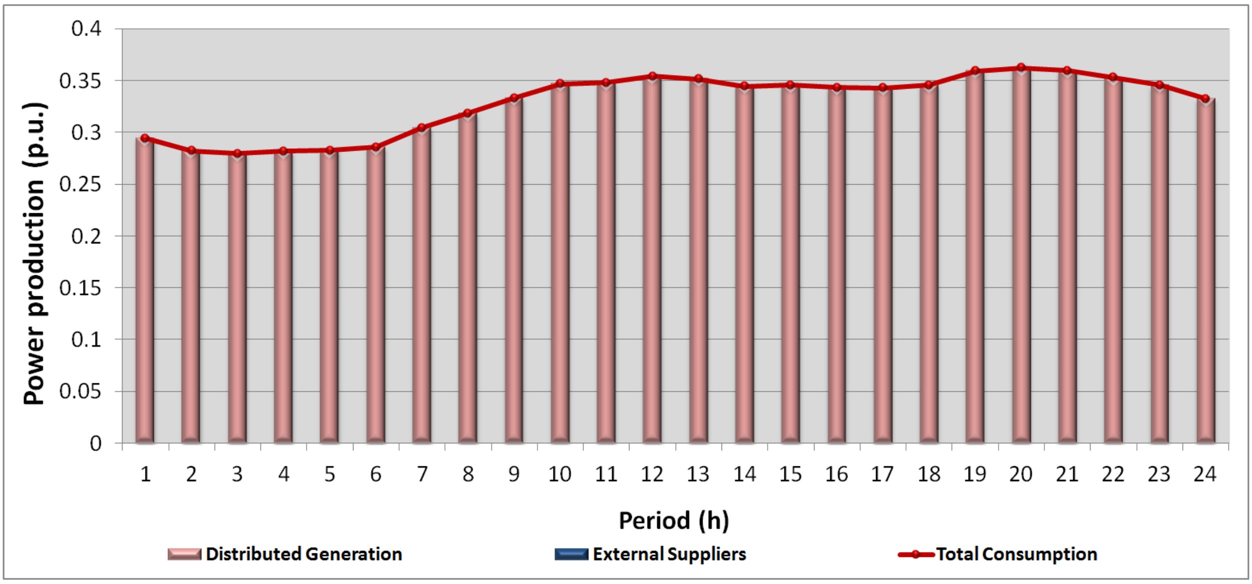

Figure C.12 – DG and external supplier dispatch for spinning reserve service, in scenario 2 of joint market model applied by VPP.

Figure C.13 shows the Regulation Down dispatch relating to scenario of section 4.6.2.3.

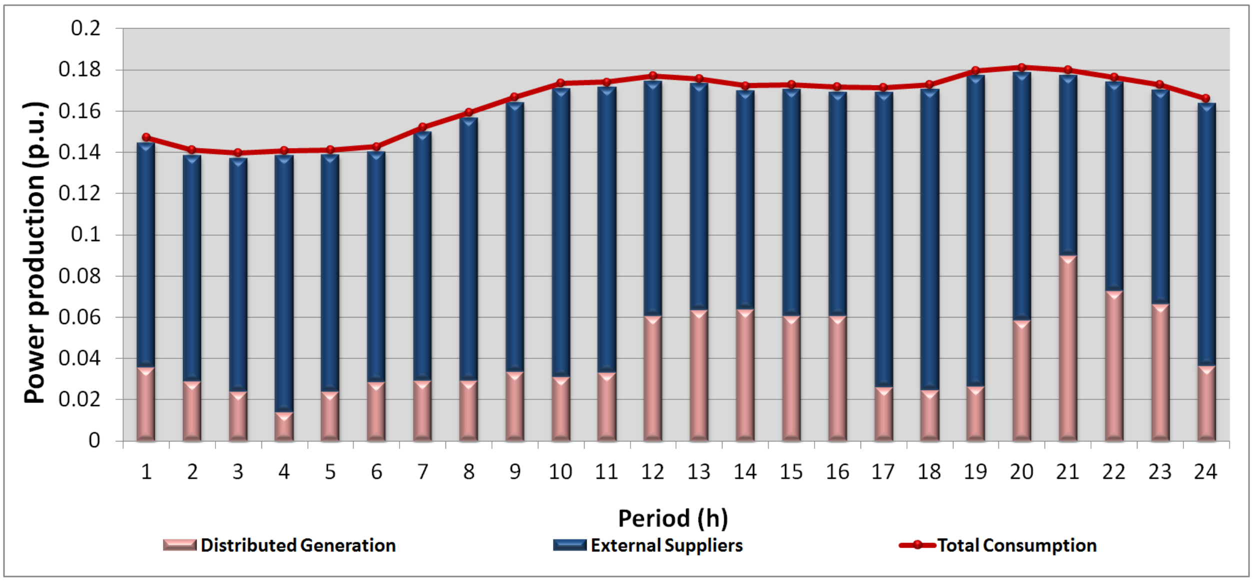

Figure C.13 – Regulation down dispatch, in scenario 3 of joint market model applied by VPP.

Figure C.14 shows the percentage of power given by each kind of resource for RD dispatch for scenario presented in section 4.6.2.3.

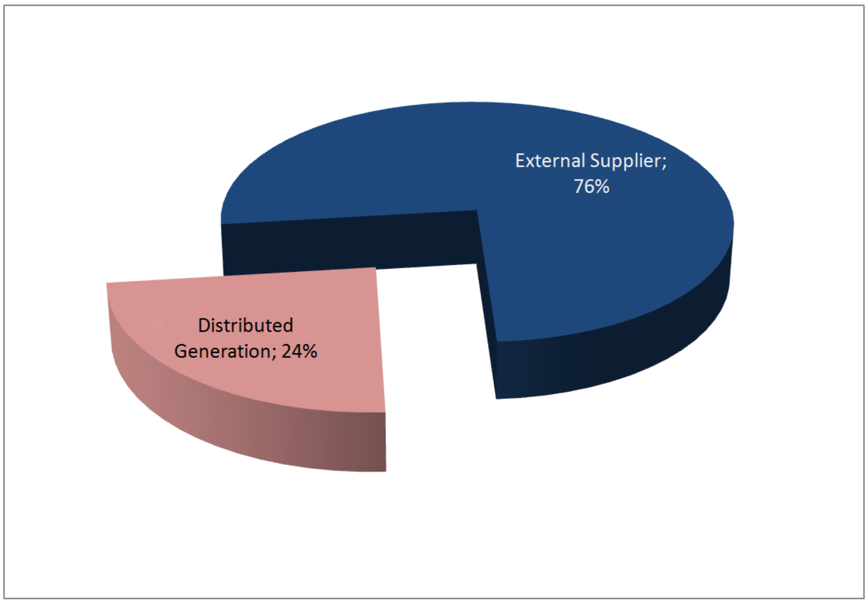

Figure C.14 – Resource contribution for regulation down service, in scenario 3 of joint market model applied by VPP.

The RU dispatch for the third scenario (section 4.6.2.3), is represented by Figure C.15.

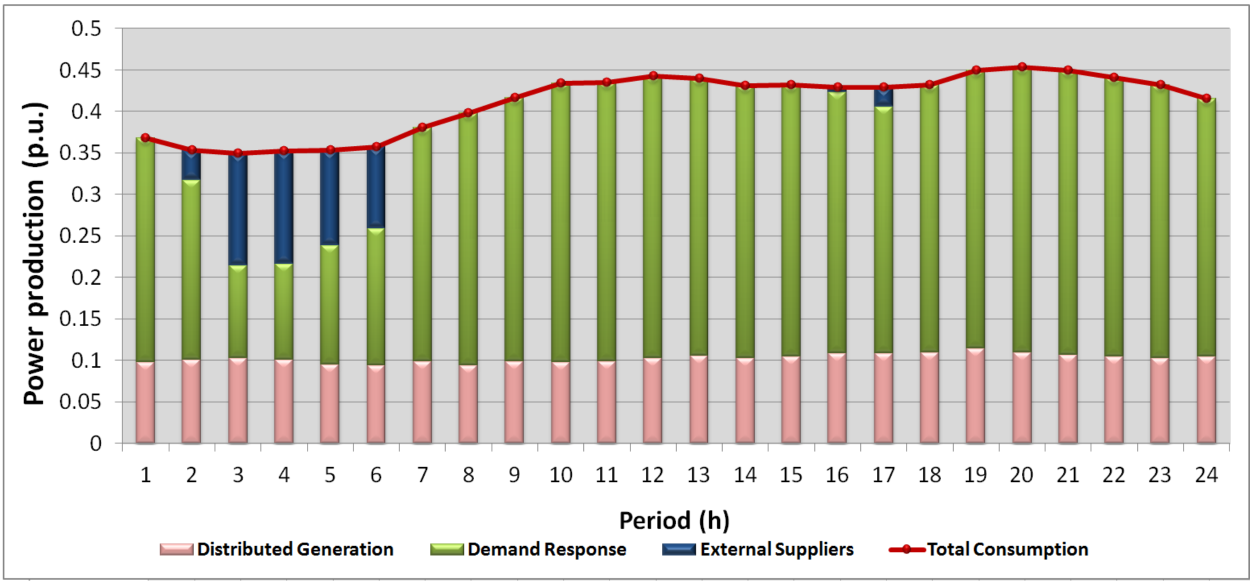

Figure C.15 – Regulation up global dispatch, in scenario 3 of joint market model applied by VPP.

Figure C.16 represents the global dispatch of Spinning Reserve for 24 hours period in respect to the third scenario presented in section 4.6.2.3.

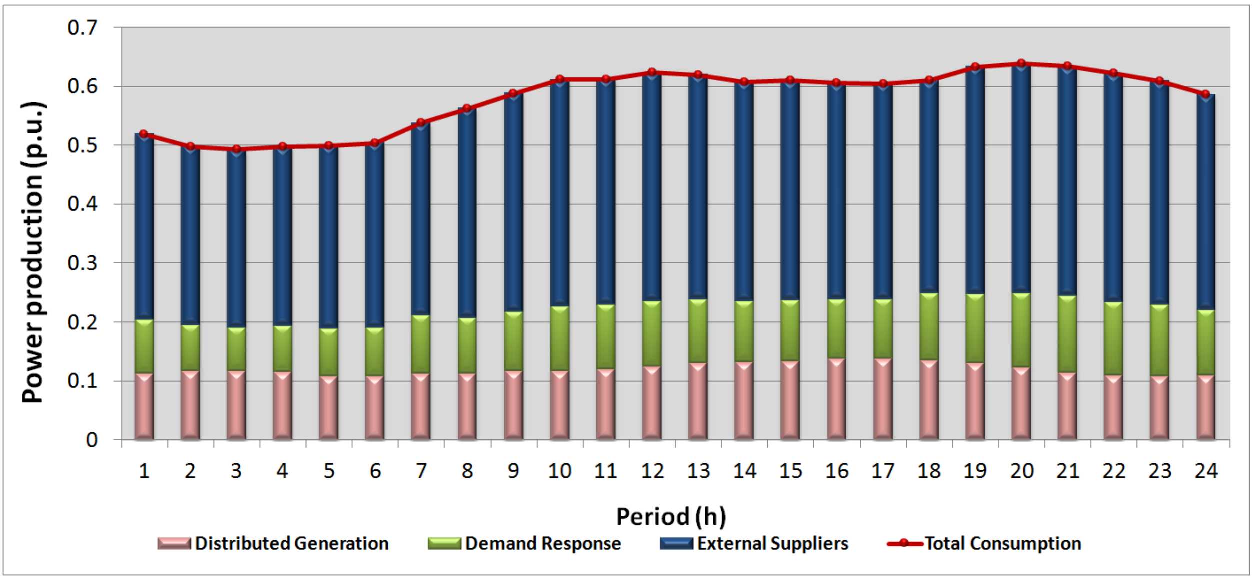

Figure C.16 – Spinning reserve global dispatch, in scenario 3 of joint market model applied by VPP.

The Spinning Reserve dispatch for each network region is given by the Figure C.17.

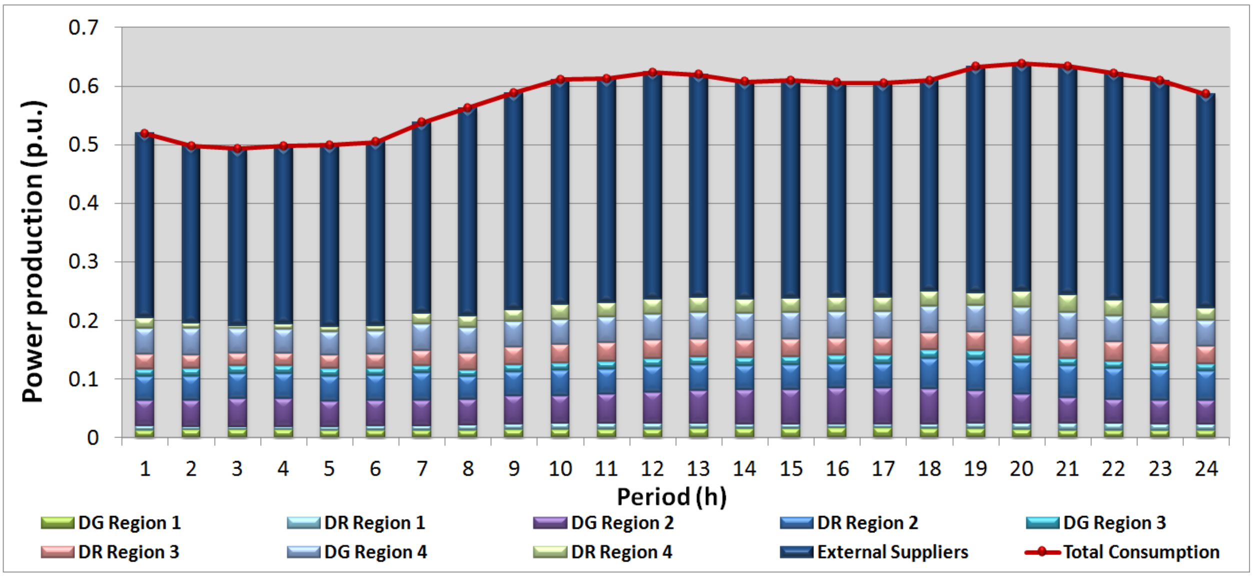

Figure C.17 – Spinning reserve dispatch by network region, in scenario 3 of joint market model applied by VPP.

The SP dispatch for Region 1, considering all kind of resources is given by Figure C.18.

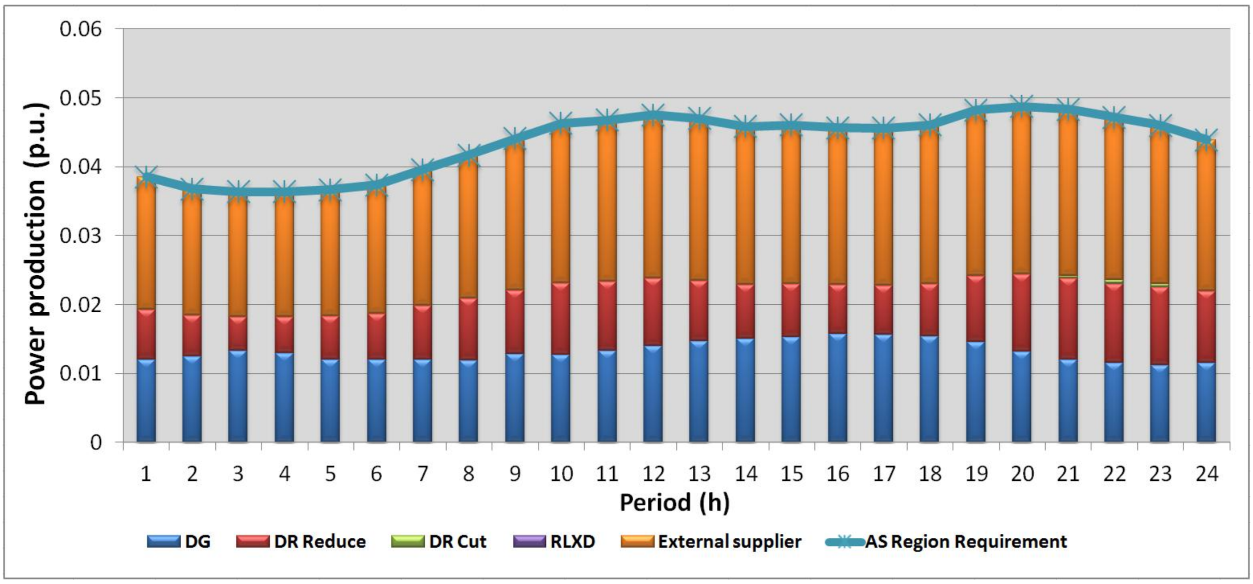

Figure C.18 – SP reserve dispatch for region 1, in scenario 3 of joint market model applied by VPP.

The SP dispatch for Region 3, considering all kind of resources is given by Figure C.19.

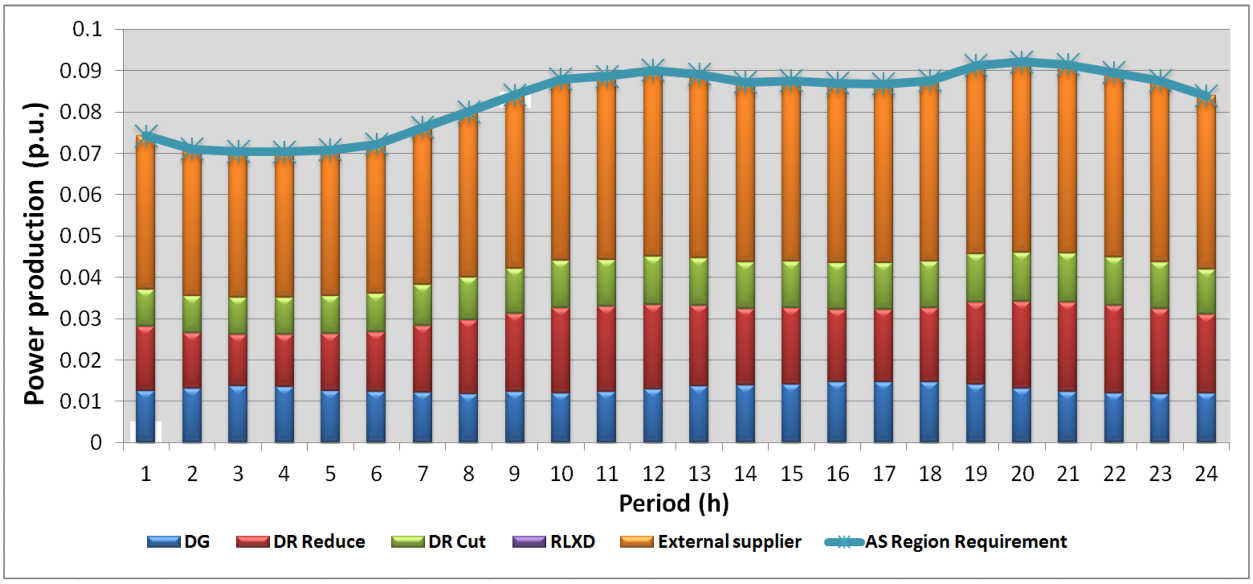

Figure C.19 – SP reserve dispatch for region 3, in scenario 3 of joint market model applied by VPP.

The SP dispatch for Region 4, considering all kind of resources is given by Figure C.20.

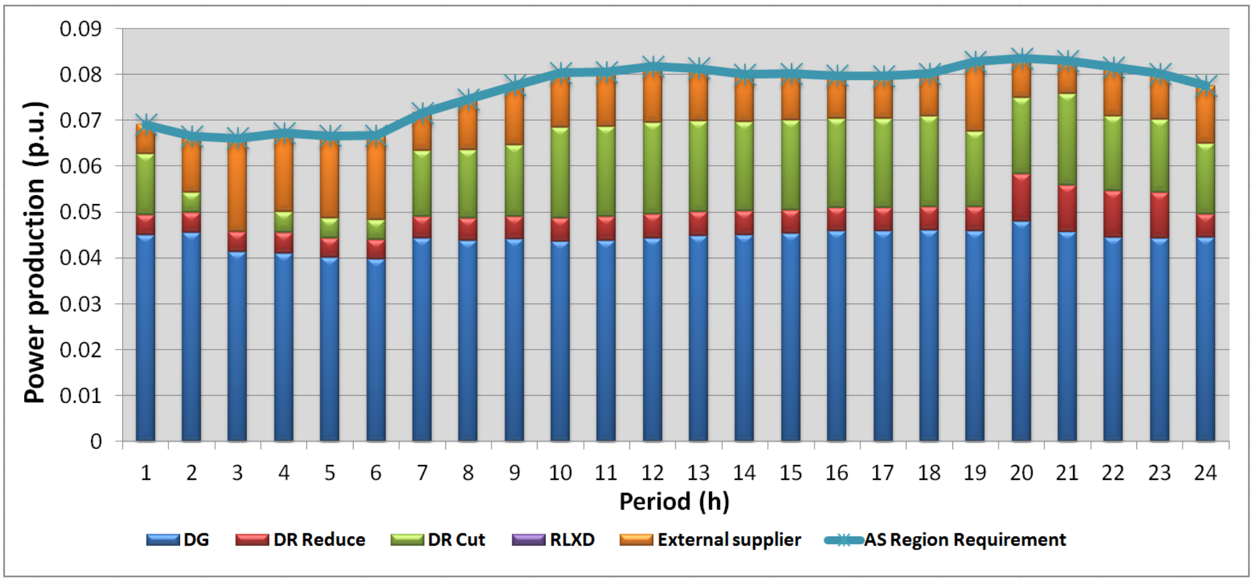

Figure C.20 – SP reserve dispatch for region 4, in scenario 3 of joint market model applied by VPP.

Figure C.21 represents the global dispatch of Non-Spinning Reserve for 24 hours period in respect to the third scenario presented in section 4.6.2.3.

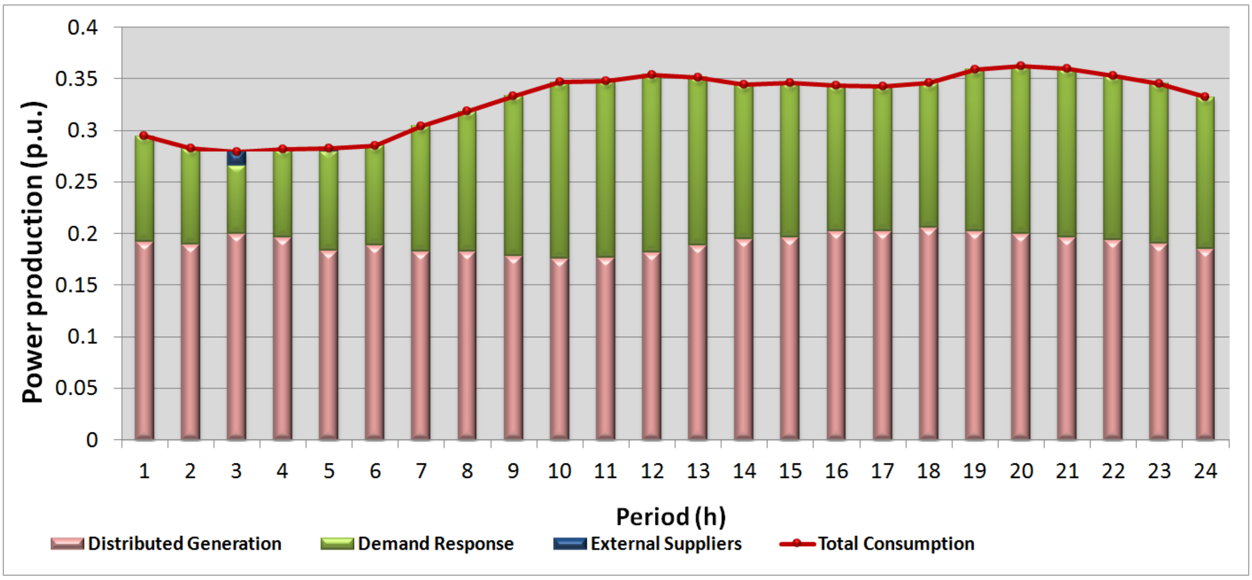

Figure C.21 – Non-spinning reserve global dispatch, in scenario 3 of joint market model applied by VPP.

Figure C.22 illustrates the energy dispatch for 24 hours period.

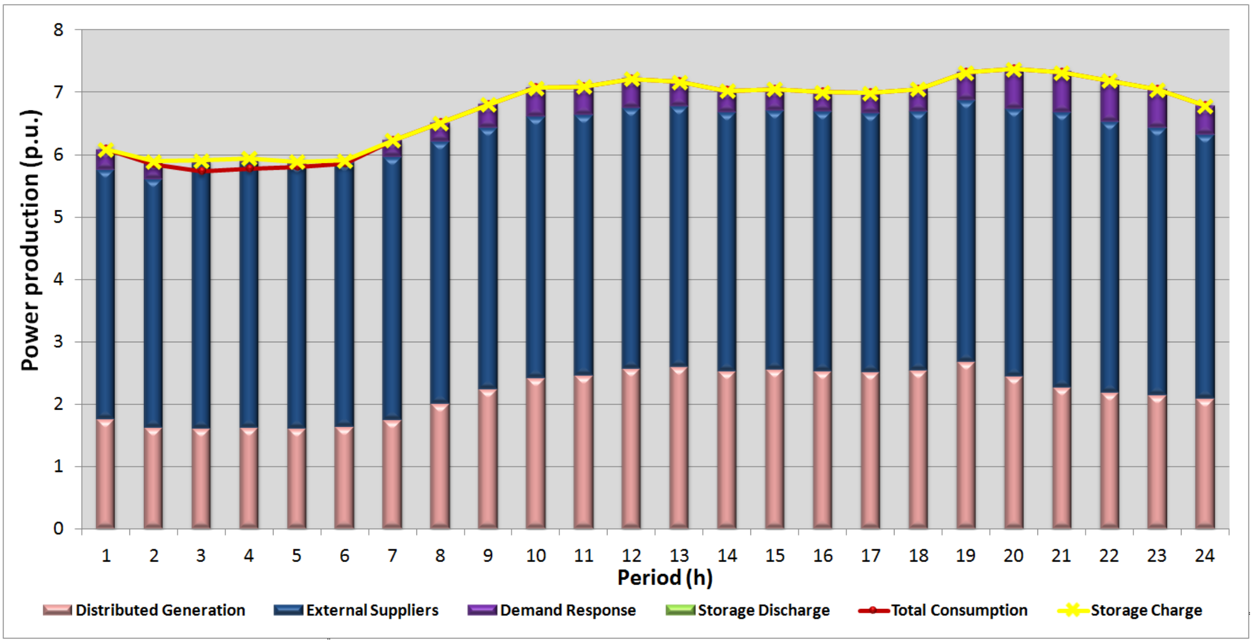

Figure C.22 – Energy dispatch, in scenario 4 of joint market model applied by VPP.

Figure C.23 presents all kinds of consumption assured by the energy dispatch (includes storage charge and active power losses).

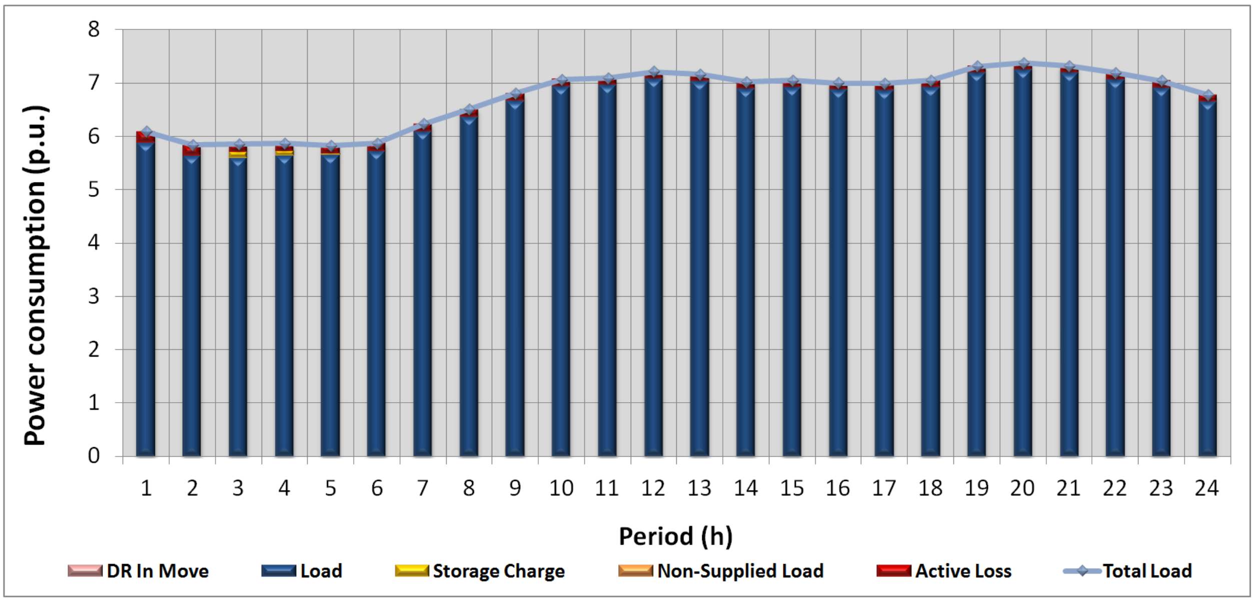

Figure C.23 – Consumption details of energy dispatch, in scenario 4 of joint market model applied by VPP.

The storage unit contribution by network regions to Regulation Up service is given by Figure C.24 – Storage charge and discharge contribution by network regions for RU service.

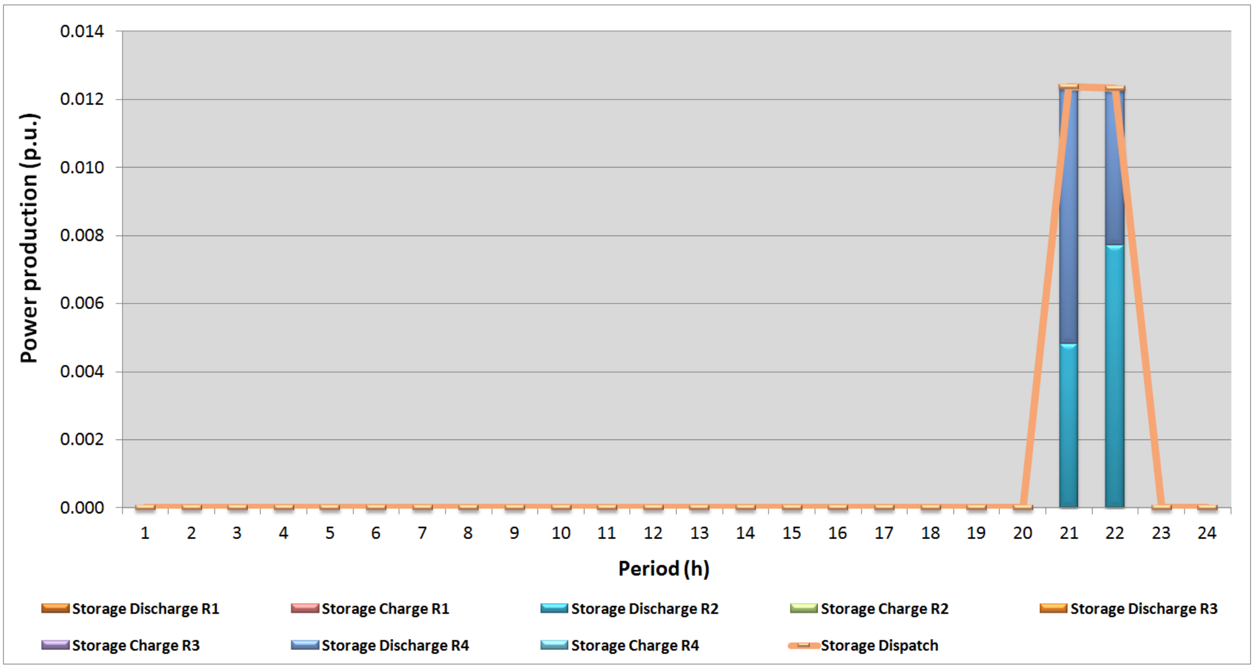

Figure C.24 – Storage charge and discharge contribution by network regions for RU service.