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EXECUTIVE SUMMARY

This deliverable is the first from the work package 6 of the GARPUR project, focusing on the short-term horizon – system operation and those (operation) planning processes done immediately ahead of real-time. It constitutes the outcome of task 6.1 "Functional workflow of the short-term decision making process". It will serve as a basis for the next tasks of GARPUR WP6, and be used as building stone in the establishment of the reliability management framework in GARPUR.

The objective of this report is to establish a detailed workflow diagram of current TSO activities in this context. The workflow identifies the different data sets and software solutions in use, the different types of decisions taken in this context, and establishes a rough time line for when the decisions are taken relative to real-time operation. The workflow diagram has been established from the point of view of a single TSO, but wherever relevant, the interactions with other external actors (mainly other TSOs and regulators) are also mentioned.

The report is divided into six chapters. After an introduction defining the scope of the work package and task 6.1, chapter 2 presents definitions and terms used in this report. Chapter 3 of this report gives a high-level overview of the transmission system operation and short-term operation planning. Chapter 4 deals with the different types of analyses in details, and discuss the major risks in system operation. Chapter 5 describes the current data (bases) and software used in system operation and short-term operation planning among European TSOs. Chapter 6 concludes this report with some general discussion points. The Appendix collects information about the questionnaire used to gather information from TSOs.

The need for probabilistic reliability management has been recognised for some time. One of the main objectives of the GARPUR project is to propose a new reliability management framework which captures the risks (from various sources) in system operation in a better way than the reliability management methods currently used. Currently, system operation is dominated by the deterministic N-1 criterion, and thus are the tasks and processes described in this report very much linked with this deterministic criterion, but this report gives some insights into how to migrate towards probabilistic reliability management within system operation.

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1 INTRODUCTION

This is the first deliverable from work package 6 in the GARPUR[1] project, where the focus is on the current status, amongst European TSO, of the short-term decision making process. This deliverable mainly deals with the processes and actions needed to ensure the reliability of real-time operation. It covers the real-time operation itself but also its preparation. Therefore, less focus is devoted to the impact of decisions on the longer term future of the system. These later aspects are dealt with in work packages 4 and 5 in the GARPUR project.

1.1 Background Information on the GARPUR Project

According to the *GARPUR Description of Work*, the GARPUR project designs, develops, and assesses new probabilistic reliability criteria and evaluates their practical use while maximizing social welfare. In response to the ENERGY call 2013.7.2.1: Advanced concepts for reliability assessment of the pan-European transmission network, GARPUR aims at:

- defining new classes of reliability criteria able to quantify the pan-European electric power system reliability in coherence with its evolution towards and beyond 2020;
- evaluating the relevance of the criteria and comparing different reliability management strategies through the impact they have on global social welfare, thus pinpointing the most favourable evolutions away from the N − 1 criterion in the decades to come.

GARPUR also aims to ensure that the new reliability criteria can be progressively implemented by TSOs at the pan-European level to address new types of system threats while effectively mitigating their consequences on society as a whole. The seven main objectives of the GARPUR project are:

- **O1:** To develop a consistent probabilistic framework for reliability management, covering the definition of reliability, the calculation of reliability criteria, and the formulation of optimisation problems expressing the economic costs and the desired target reliability levels at the pan-European level and within each individual control zone.
- **O2:** To develop a consistent methodology for the quantitative evaluation of the economic impact on society of different reliability management strategies both at the pan-European level, and within each control zone.
- **O3**: To develop a quantification platform able to compare different reliability management strategies in terms of their impact on the social welfare.
- **O4**: To ensure the compliance of the developed methodologies with the technical requirements of system development, asset management and power system operation, and to demonstrate the practical exploitability of the new concepts at the pan-European level and in all decision making contexts.
- **O5**: To validate the different reliability criteria with the help of pilot tests.
- **O6**: To ensure the general acceptance of the proposed methods and tools by all stakeholders affected by the reliability management of the pan-European electric power system.
- **O7**: To define an implementation roadmap towards the use of the new reliability management practices.

[1] http://www.garpur-project.eu/

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1.2 Background Information on GARPUR WP6 and Task 6.1

In the GARPUR project, work package 6 discusses system operation and those (operation) planning processes done immediately ahead of real-time system operation, i.e., the last decision-making context. To roughly define the time horizon, it ranges from real-time operation up to the point where forecasts are available (as opposed to longer-term analyses, where historical records and/or distributions of the relevant variables are of more value for the analysis). In this context, only the existing (and available) network/system components can be activated and used, with no opportunity to add new equipment. Of course, some modifications of the network and available components are possible through reserve procurement, switching, adjusting reactive compensation, reconnecting equipment disconnected for maintenance purposes, etc. The relation of WP6 within the GARPUR reliability management framework is highlighted in Figure 1.1. Work package 4 and 5 in GARPUR deal with the grey areas in the Long Term and Mid Term columns in Figure 1.1.

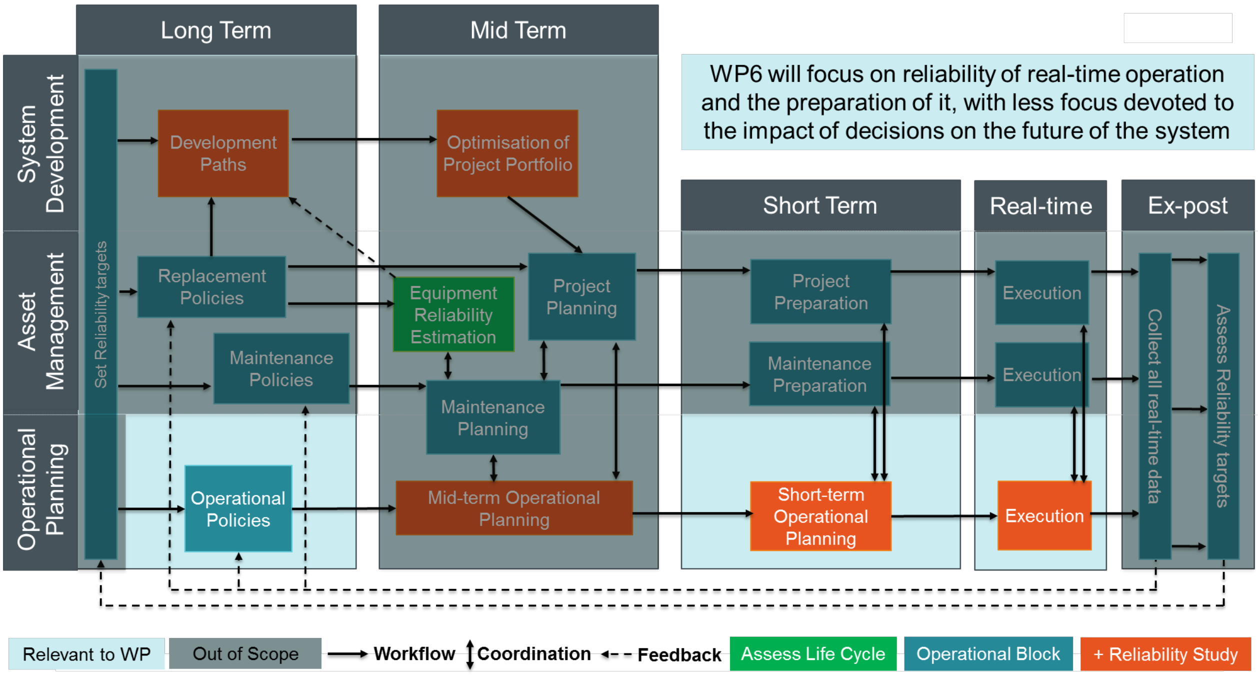

Figure 1.1: Scope of WP6 within the GARPUR reliability management framework

All analyses done by TSOs in this context are done to prepare (for secure) system operation, and to have options available for potential problems that might occur in real-time operation, e.g., problems as a consequence of contingencies or large forecast errors. Another important aspect, in the last decision-making context, is the final acceptance of the outage requests from system development projects (project execution), asset management (maintenance execution) and external parties such as from neighbouring TSO, DSO's, and generators. The question the TSOs need to answer is whether or not the requested outage(s) will result in a too vulnerable system. The increased vulnerability has to be balanced with the future needs of the system, e.g., if no planned outages are accepted, maintenance becomes impossible, the system will progressively wear down, and long-term reliability will suffer. Such trade-offs are further discussed in D5.1 [GARPUR, 2015a].

Please note the division of work in the GARPUR project between WP4-5-6 (illustrated for WP6 in Figure 1.1) does not at all intend to reflect the internal organisation of a TSO in terms of departments/units. Furthermore, mid-term operation planning is dealt with in WP5 instead of WP6 to simplify the exposition of coordination between maintenance and operational planning and its effect on system risk.

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The aim of task 6.1 is to establish a detailed workflow diagram of current TSO activities in the context of GARPUR work package 6. The workflow identifies the different data sets and software solutions in use, the different types of decisions taken in this context, and establishes a rough time line for when the decisions are taken relative to real-time operation. In addition, some opportunities to better coordinate these decisions, to improve coordination with neighbouring agents, and environmental considerations are identified.

The workflow established by task 6.1 is largely based on information extracted from a questionnaire sent to 10 European TSOs. The questions asked are found in Appendix 1. The goal is to have a workflow describing the activities of an "average" European TSO, which again is used as input to the process of defining a new reliability management framework and reliability criteria in the GARPUR project. By the term "average TSO", it is meant that most European TSOs should be familiar with the tasks, processes, and workflow structure, but will most likely find some of their particularities missing. Solutions proposed by the GARPUR project will be designed to best fit the needs of such an "average TSO", while allowing for enough flexibility to cope with the specific needs of actual TSOs.

1.3 Report structure

The report is divided into six chapters. Next, in Chapter 2, definitions and terms used in this report are described. Chapter 3 gives a high-level overview of transmission system operation and short-term operation planning. Chapter 4 describes the current practices of TSOs in general, in a manner that is detailed enough to describe the main functions of a TSO, whilst being simple enough to be generally applicable to all TSOs in Europe. The major risks in system operation are also discussed in Chapter 4. Chapter 5 describes the current data (bases) and software used in system operation and short-term operation planning amongst European TSOs. Chapter 6 concludes this report and gives some general discussion points and conclusions with respect to how to migrate towards probabilistic reliability management within the system operation process. The Appendix collects information about the questionnaire used to gather information from TSOs.

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2 TERMS AND DEFINITIONS

2.1 Definitions

Asset management Systematic and coordinated activities and practices through which an organization optimally manages its physical assets and their associated performance, risks and expenditures over their lifecycles for the purpose of achieving its organizational strategic plan [BSI, 2004]. In the GARPUR context, asset management encompasses system development activities undertaken by a TSO in the mid-term planning horizon.

Balancing All actions and processes, on all timelines, through which the TSOs ensure, in a continuous way, to maintain the system frequency within a predefined stability range as set forth in the Network Code on Load-Frequency Control and Reserves, and to comply with the amount of reserves needed per Frequency Containment Process, Frequency Restoration Process and Reserve Replacement Process with respect to the required quality, as set forth in the Network Code on Load-Frequency Control and Reserves [ENTSO-E, 2013a].

Candidate Decision An alternative that can be selected by means of reliability management in a given context [GARPUR, 2014a].

Congestion A transmission line is considered to be congested “if it would be overused if its limit were not enforced” [Stoft, 2002]. Congestions might be an outcome of a market clearing process if transmission constraints are disregarded as in case of uniform pricing.

Congestion management Congestion management is the application of a set of actions or procedures that resolves congestion in order to avoid the overloading of power lines or interconnectors during grid operation. One may distinguish between ex-ante (before the energy auction is cleared) and ex-post (after the energy auction is cleared) congestion management methods [Kumar et al., 2005]. Also, congestion management methods can be categorized according to whether they are market-based (e.g. counter trading) or non-market-based [de Vries, 2001]. Furthermore, actions can be taken within one control area or can involve more than one TSO.

Connection point Connection point is the interface at which the power generating module, demand facility, distribution network or closed distribution network is connected to a transmission system, distribution network or closed distribution network [ENTSO-E, 2013e].

Consequence Consequence is the outcome of an event. Note: There can be different types of consequences: technical (like interruption), economic or environmental consequences, consequences on personnel/ consumers safety, etc. See GARPUR Deliverable D1.1 [GARPUR, 2014b].

Contingency A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages [ENTSO-E, 2004].

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Control Area	Control area is a part of the interconnected electricity transmission system controlled by a single TSO [ENTSO-E, 2004].
Event	The general term event is defined as occurrence of a particular set of circumstances [ISO, 2009]. In recent books, [Rausand, 2011] and [Hokstad, et al., 2013], the authors distinguish between hazardous and initiating events, and accident scenarios (sequence of events). Often in power systems, terms like failure events and extraordinary (or exceptional) events, are used.
Indicator	An indicator is an observable or computable quantity that provides insight into a concept or a system that is difficult to measure directly [OECD, 2003].
Long-term horizon	The long-term horizon in GARPUR covers development of the existing system, to ensure secure operation by adapting to significant changes in system utilization.
Mid-term horizon	The mid-term horizon in GARPUR covers managing existing system assets to ensure future secure operation, for which the power system structure cannot be significantly changed.
N-0 criterion	The N-0 criterion means accepting more severe consequences after certain faults [GARPUR, 2014b].
N-1 criterion	The N-1 criterion is a principle according to which the system should be able to withstand at all times a credible contingency – i.e., unexpected failure or outage of a system component (such as a line, transformer, or generator) – in such a way that the system is capable of accommodating the new operational situation without violating operational security limits. (This definition is partly based on ENTSO-E documents [ENTSO-E, 2004] and [ENTSO-E, 2013c])
N-1 situation	The N-1 situation is defined as the status of the TSO´s responsibility area after an event defined in the contingency list used by the N-1 criterion [ENTSO-E, 2009].
Normal state	According to ENTSO-E's Network Code on Operational Security, published in September 2013 [ENTSO-E, 2013d], a normal state means the system state where the system is within operational security limits in the N-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions. A different definition can be found in the Continental Europe Operational Handbook and its Policy 5 Emergency operations [ENTSO-E, 2010]. In this handbook a normal state means that there is no risk for interconnected system operation. All consumption and production are in balance and requirements on ancillary services and framework conditions are met; frequency, voltage and power flows are within their predefined and allowed limits (thresholds) and reserve (margins) are sufficient to withstand pre-defined contingencies. Operation is within normal limits, taking into account remedial actions effects.
Operational planning	Operational planning is the group of reliability management activities linked to system optimization occurring ahead of real-time operation, within the short-term and mid-term horizons.

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Operational policies	Constitute the doctrine developed for interconnected systems operation; they form the main part of the Operation Handbook [ENTSO-E, 2014b]. Each doctrine consists of criteria, standards, requirements, guides, and instructions, and applies to all control areas. [ENTSO-E, 2004]
Operational scheduling	Operational scheduling means generating a reference set of values representing the generation, consumption, or exchange of electricity between actors for a given time period, and the state of controlled system components according to the outage schedule.
Operational security	Operational security means the transmission system capability to retain a normal state or to return to a normal state as soon and as close as possible, and is characterized by its thermal limits, voltage constraints, short-circuit current, frequency reference value and stability limits [ENTSO-E, 2013d].
Operational security analysis	Operational security analysis means the entire scope of the computer based, manual and combined activities performed in order to assess operational security of the transmission system, including but not limited to: processing of telemetered real-time data through state estimation, real-time load flows calculation, load flows calculation during operational planning, contingency analysis in real-time and during operational planning, dynamic stability assessment, real-time and offline short circuit calculations, system frequency monitoring, reactive power and voltage assessment [ENTSO-E, 2013d].
Outage	An outage is the state of a component or system when it is not available to properly perform its intended function due to some event directly associated with that component or system [IEEE, 1997].
Power system	In this document power system is a system that consists of transmission grid, generators, loads, distribution grids, adjacent transmission systems (with their generators, loads etc.) [GARPUR, 2014a].
Power system adequacy	Power system adequacy is the ability of the system to supply the aggregate electric power and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of the system components [Kundur et al. 2004].
Power system reliability	Power system reliability means the probability that an electric power system can perform a required function under given conditions for a given time interval [IEC, 2009].
Power system security	Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances [Kundur et al. 2004]. Security is the ability of the power system to withstand sudden disturbances such as short circuits or un-anticipated loss of system components. Another aspect of security is system integrity, which is the ability to maintain interconnected operations. Integrity relates to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of specified severe disturbances [ENTSO-E, 2004].

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Preventive operation In the real-time context, preventive operation concerns the potential application of pre-contingency actions to achieve security and improve the ability to withstand the possible effects of potential contingencies [GARPUR, 2014a].

Price area Several nodes are grouped together to form one price zone, yet several price zones exist within the electric grid. Without congestions in the system, there is one price as in uniform pricing. In case of congestion, the market prices differ between the prices zones separated by the congestion.

Reactive power Reactive power is the imaginary component of the apparent power at fundamental frequency, usually expressed in kilovar (kvar) or megavar (Mvar) [ENTSO-E, 2013e].

Real-time horizon The real-time horizon (system operation) in GARPUR focuses on the observed system state, i.e., it covers monitoring, control of the power system, and actions based on observed system state. Control covers corrective actions and activating manual preventive (planned) actions.

Re-dispatch (also Redispatch) Redispatching means a measure activated by one or several system operators by altering the generation and/ or load pattern, in order to change physical flows in the transmission system and relieve a physical congestion [ENTSO-E, 2013e].

Reliability management Power system reliability management means to take a sequence of decisions under uncertainty. It aims at meeting a reliability criterion, while minimising the socio-economic costs of doing so [GARPUR, 2014b].

Remedial action Remedial action means any measure applied by a TSO in order to maintain operational security. In particular, remedial actions serve to fulfil the N-1-criterion and to maintain operational security limits [ENTSO-E, 2013e].

Short-term horizon The short-term horizon in GARPUR covers planning for secure operation of forecasted power system states, for which the power system components cannot be changed through maintenance works and/or system development projects.

System state Refer to Section 4.2.6.

Threat Threat can be defined as any indication, circumstance, or event with the potential to disrupt or destroy a system, or any element thereof. This definition includes all possible sources of threats, i.e., natural hazards, technical/operational, human errors, as well as intended acts such as terror and sabotage [EU Commission, 2005]. It may also be defined as anything that might exploit vulnerability [Rausand, 2011].

Topology Topology means necessary data about the connectivity of the different transmission system or distribution network elements in a substation. It includes the electrical configuration and the position of circuit breakers and isolators [ENTSO-E, 2013e].

Transmission system Transmission system means the electric power network used to transmit electric power over long distances within and between member states. The transmission system is usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages [ENTSO-E, 2013e].

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Vulnerability	Vulnerability is an internal characteristic of the system and it relates to the inability of a system to perform a required function due to the realization of a threat. More specifically, a system that is likely to fail to carry out its intended function, has problems recovering to normal function or its capacity is significantly reduced upon realization of a threat is vulnerable to the said threat [Hoffmann et al., 2011].

2.2 Section 4 workflow diagram labels

Rel	Setting of Reliability Targets
PD	Project Development
Ox	Operational Policies
PP	Project Planning
PS	Project Scheduling
PE	Project Execution
MP	Maintenance Planning
MS	Maintenance Scheduling
ME	Maintenance Execution
OP	Operational Planning
OS	Operational Scheduling
OE	Operational Execution
Per	Assessment of System Performance

2.3 Section 5 data, software and coordination acronyms

AGC	Automated Generation Control
AMS	Asset Management System
AVC	Automated Voltage Control based on OPF
CA	Contingency Analysis
CIM	CIM data format
CORESO	COoRdination of Electricity System Operators
CTDS	Common Tools for Data exchange and Security assessment
D2CF	2 Days-Ahead Congestion Forecasts
DACF	Day-Ahead Congestion Forecasts
DB	Database
ENS	Energy Not Supplied
FACTS	Flexible AC Transmission System
FCR	Frequency Containment Reserves
FRR-A	Frequency Restoration Reserves – Automatic
FRR-M	Frequency Restoration Reserves – Manual (also: Replacement Reserves)
GCC	Grid Control Cooperation
IGCC	Inter TSO Generation Control for secondary
eGCC	regulation of Power and frequency
GECO	Generation Company
IDCF	Intraday Congestion Forecasts
IDS	Integrated Data Store
PF	Power Flow
LFC	Load Frequency Control

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LT	Long Term / Long Time
MMS	Marked Management System
MT	Mid-Term / Middle Time
OPF	Optimal Power Flow
SVC	Static Var Compensator
OCS	Optimal Control Switching
RD	Redispatch (a generation change proposals)
RDB	Real time Database
RT	Real Time
SC	Short Circuit calculations
SCOPF	Security Constrained Optimal Power Flow
SDB	Simulation Database = temporary off-line database
SE	State Estimation
SN	Snapshot (time-cut though a database)
ST	Short Term / Short Time
TP	Topology
TSC	TSO Security Cooperation
UCTE	Union for the Coordination of Transmission of Electricity data format
WAMS	Wide Area Monitoring System

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3 REAL-TIME OPERATION AND SHORT-TERM OPERATION PLANNING

This chapter introduces current practices of European TSOs with respect to tasks and analyses in real-time operation and (short-term) operation planning. The description of the activities is, for the most part, based on a questionnaire sent to 10 European TSOs. The responses from the 10 TSOs cover the Nordic countries and Continental Europe, representing different system sizes, characteristics, and control zones. This chapter deals with the high-level activities and general challenges in operation and operation planning, while the subsequent chapters describe the more specific processes, data, and software in detail.

3.1 Real-time operation

The first part (see Appendices A1.2.1 and A1.2.2) of the questionnaire asked about what the main tasks in real-time operation are, and about the main variables the TSOs monitor and (attempt to) control. According to the responses, the main tasks in real-time operation are:

- Monitoring of power flows
- Balancing
- Maintenance supervision and last-minute changes
- Reacting to contingencies
- Congestion management
- Publish market messages
- Switching
- Voltage control

The main variables that are monitored in real-time operation are:

- Frequency
- Voltage
- Power flows (active and reactive)
- Load/consumption (at specific locations)
- Generation: active and reactive power levels (including RES)
- Transformers tap changer levels
- HVDC links active and reactive power levels
- Transformer and reactor (hot spot) temperature
- Production of each power plant connected to the transmission grid and a total for generation plants by type, connected to distributions grid
- Level of activation of the reserves
- Area Control Error

Of course, some of these variables are not present or important in all systems (e.g. Wind Power Plants) and are thus not monitored by all TSOs. How the TSOs monitor the variables varies depending on the importance of the variable for the given system, and what type of technical solution the TSO has chosen. There are also varying detail levels with respect to production monitoring among European TSOs.

Some of the TSOs specifically mention wind power generation as a separate monitored variable from "conventional" generation. In real-time, RES generation is usually considered to have the same

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predictability level as conventional generation[2]. In the planning phase, many TSOs have specific models for predicting generation from RES, which are used in reserve management.

Some of the above mentioned variables can be controlled directly, while others must be controlled indirectly by means of remedial actions (such as power redispatch to change power flows). The main controlled variables, either direct or indirect, reported by TSOs are:

- Frequency
- Voltage
- Power flows
- Topology (breakers and connectors)
- Transformers and power lines loads
- Active and reactive power generation (conventional and RES)
- Transformers tap changer levels
- HVDC links active and reactive power levels
- Area Control Error

The TSOs were asked what they regard to be the major risks in system operation (see Appendix A.1.2.2). The list below shows what cases/situations the TSOs consider to be the most threatening to secure system operation:

- Large unintended (cross-border) flows
    - Beyond phase-shifting transformer capabilities
    - Beyond overload protection/automatics or system protection/automatics
- Outage of several generators
    - Beyond under and over protection of generating units
- Lack of reserves (if disconnected from neighbouring areas)
- Simultaneous line outages
- Tower faults due to bad weather
- Low hydropower reservoir levels
- Volcanos, earthquakes, avalanches/landslides
- Severe weather situations (storms, hurricanes, flooding, low water level (lack of cooling), hail storms, ice, etc.)
- Cascading overloads and islanding (part of the system)
- Lack of generation flexibility

As before, some of these threats are obviously single TSO specific, while others are more or less common to all TSOs.

Detailed analyses of the different tasks, and how they affect system reliability, are provided in Section 4.

3.2 Short-term operation planning

Similar to real-time operation, there was a question (in the questionnaire) asking the TSOs about the main task/activities in operation planning. The answers were:

- Scheduling (Intraday, day ahead, week ahead, etc.)
- Load forecasting
- RES generation forecasting

[2] E.g. the burning value of gas can vary quickly, so fluctuations from gas fired generators have a certain fluctuation comparable to wind and photovoltaic power generators.

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- Maintenance plan adjustment and implementation
- Balancing plans (intraday, day ahead, week ahead, months ahead)
- Power flow and contingency analyses

An interesting fact is that none of the TSOs explicitly mentioned reserves in this context, but reserve management can be seen as an integral part of many of the activities above. As in the previous section, not all activities are relevant for all TSOs, but the list above should reflect an average TSO fairly well.

3.3 Expected tasks to be performed in the near future

The questionnaire also asked TSOs to describe the analyses that are rarely performed today, if at all, that they believe will become more important or more frequently used in the future. The answers, which contained elements from both real-time operation and operation planning, are shown below:

- SCOPF (Security Constrained Optimal Power Flow and corrective switching)[3]
- Explicit integration of uncertainties in decision making process
    - RES forecasting
    - Market
- Clear decision criteria for interaction between asset management tasks (maintenance work, grid reinforcement work) and real-time reliability (e.g. maintenance cancellation)
- Clear risk-based decision criteria for operating criteria (temporary overvoltage levels, temporary overload) impacting lifetime and reliability of asset equipment's and real-time reliability
- Taking into account dynamic line rating devices in planning (for the moment, only taken into account in real-time)
- Online short circuit level calculations
- Reactive power calculations (N-1)
- Quantitative evaluation of probabilities of failure
- Economic evaluation of outages
- Visualization
    - Weather related risks
    - Outage analysis
    - Elements of critical failure path
- Analysis of corrective vs preventive actions
- Real time surveillance of primary automatic reserves and inertia
- Dynamic (real-time) analysis

3.4 High level workflow diagram

Based on the information provided by the TSOs, a high-level diagram was created to show the different tasks on a time scale and to show the interaction and/or dependencies between different tasks and processes going on at the same time. The diagram is shown in Figure 3.1. The subjective division of the tasks into the different categories is done to promote discussion of the tasks in a limited context. The categories are discussed in the subsections in Chapter 4 of this report.

[3] The target of SCOPF is to alleviate existing or potential violation of security constraints like overloading or voltage problems. This task makes sense in ST horizon and RT as well. The pre-fault and post-fault control actions (decisions) are computed after contingency evaluation, after identification of critical contingencies and after decision whether preventive or corrective type of action is necessary or sufficient.

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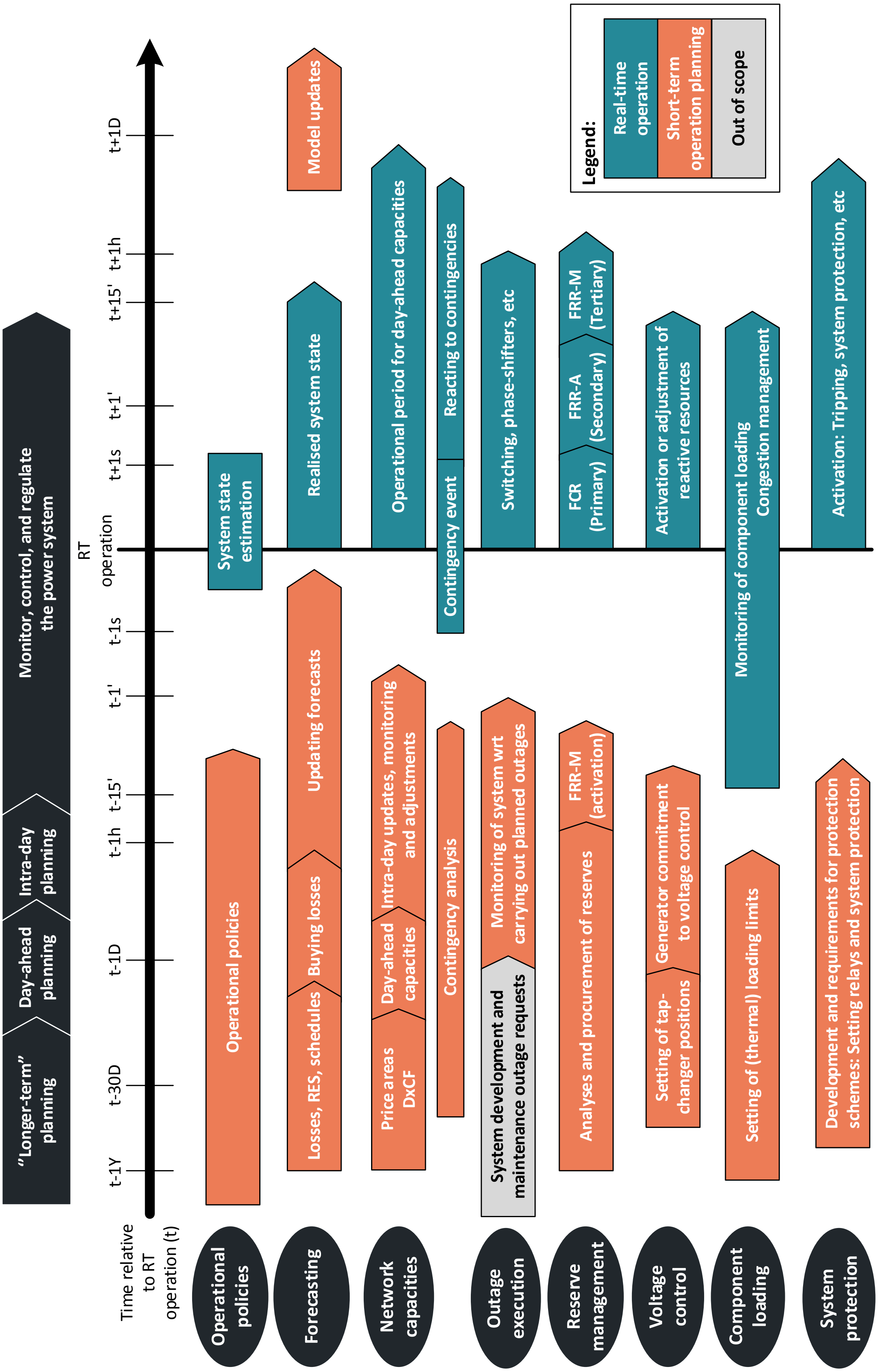

Figure 3.1: High level workflow diagram

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4 HIGH-LEVEL WORKFLOW DIAGRAM: CURRENT PRACTICES FOR EUROPEAN TSOs

This chapter describes the current practices of TSOs in general, in a manner that is detailed enough to describe the main functions of a TSO in a Systems Operations context, whilst being simple enough to be generally applicable to all TSOs in Europe. The chapter consists of an initial overview, followed by eight sections each containing a workflow diagram, and finally a section discussing the workflow diagrams in the context of the GARPUR project. It should be noted that the eight workflow diagrams occur in parallel, are interrelated, and are shown separately in this document only for the sake of clarity.

4.1 Chapter overview

The eight work flow diagrams in this chapter are used to describe the timing and relationships of major operational tasks. Tasks that take place outside of the short-term horizon, that are relevant or affect real-time operation, are also shown in the workflow diagrams. They have been included because the options available in the short-term planning and real-time horizon are largely constrained by decisions and actions taken long before. Additionally, decisions regarding policies and reliability targets, relevant only to the system operations context, are made infrequently and therefore affect operational tasks far into the future.

The general TSO tasks (Figure 1.1) are used as a basis for the detailed work flow diagrams in the sub-sections of Section 4. This legend is shown below in Figure 4.1. The Operational Policies (Ox), Scheduling (OS) and Execution (OE) tasks are the main sections of the high-level diagram that are relevant to System Operations. Mid-term Operational Planning (OP) is shown to be external to the System Operations workflow, as it is discussed in GARPUR report D5.1 [GARPUR, 2015a]. Operational Scheduling (OS) in these diagrams is equivalent to 'short-term operational planning'. The remaining tasks (shown in gold) are those that are not within the System Operations context, but provide important inputs into the System Operations workflow. The labels on the right-hand side of each box in the figure are used as labels for individual tasks within the workflow diagrams to show how information flows between these high-level tasks.

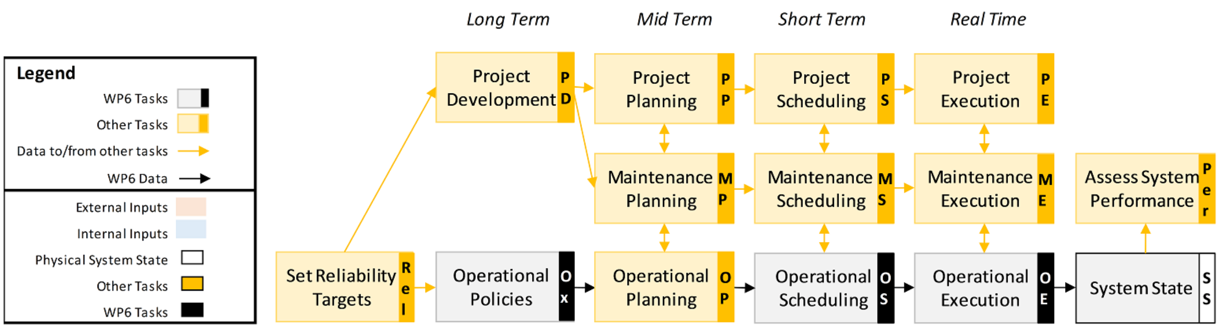

Figure 4.1: Legend and reference diagram for the task specific work flow diagrams in Section 4

The main tasks of TSOs within the context of System Operations were determined from the questionnaire sent to TSOs within the GARPUR project (See A.1.2 - question 4). In order to provide a clear separation of tasks in the workflow diagrams, the main tasks have been categorised as:

- Operational policy
- Forecasting
- Network capacities
- Outage execution
- Reserve management

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- Voltage control
- Control of component loading
- System protection

In order to thoroughly describe the system operation process, each of the tasks listed above have been given an individual sub-section and workflow diagram. In reality these eight workflows occur simultaneously. For example, the operational policies defined in Section 4.1 determine the constraints placed on other tasks. The forecasting process provides inputs for many other procedures (such as reserve management). The last five workflows, which affect the system state directly, are generally considered in parallel when responding to an unexpected change in the system. Specifically the reserve management and component load control workflows both describe actions which may be used to rectify frequency instability in transmission systems. Actions that affect the system state are shown only as corrective actions on the workflow diagrams. It should be noted that all corrective actions can also be taken as a preventive action.

The time frames of individual tasks within the workflow diagrams are defined by orders of magnitude (minutes, hours, days, weeks, months and years) to ensure that the diagrams are generally applicable to most TSOs. Each workflow diagram consists of a list of tasks on the left-hand side, corresponding boxes on the right-hand side. The position of the box describes the time frame in which the task takes place. The label inside the box describes the context, in line with Figure 4.1 (e.g., OS = Operational Scheduling), and the colour of the box defines whether it is considered as a Systems Operation task or not. Multiple boxes in a single line simply define multiple output events for a single task. The vertical dashed lines imply that the task at the bottom of the dashed line uses the above connected tasks as input. Feedback outputs describe task outputs which affect future outputs of the same task (e.g., the persistence of some policy change), or affects some previous task with a line from the feedback input column (e.g., the output of system performance data is linked to the input of system performance data). The exogenous input column defines tasks where external information/actions influence the System Operations process. These tasks are those which aim to predict some unknown future parameter (e.g., weather) or require input from a non-TSO entity (e.g., a generator, or another TSO). The tasks with exogenous inputs are those which are most interesting within the context of reliability management.

Sections 4.2 to 4.9 contain the eight System Operations workflow diagrams. Each workflow diagram is discussed in a general sense at the start of each section, followed by detailed explanations of the individual line items after the diagram to assist in their interpretation. The detailed explanations elaborate on the items listed in the workflow diagrams, defining what the task involves and what the links shown on the diagram mean.

Section 4.10 contains the main conclusions of the workflow portion of the report, discussing the workflow diagrams in the context of reliability management and the GARPUR project.

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4.2 Operational Policy

This process refers to the creation and revision of policies that govern the methods and procedures used in TSO operation. The operational policies are dependent upon (existing and new) regulations created by governing bodies, as well as internal reliability targets informed by system performance data. The operational policies don't directly affect the state of the transmission system, but indirectly through defining the procedures and constraints for all other workflows. It is also through this workflow that high-level changes to system operation are made, such as the adoption of new risk management techniques. The Operational Policy process is described by the detailed work flow diagram below in Figure 4.2. The individual line items are discussed in more detail after the diagram.

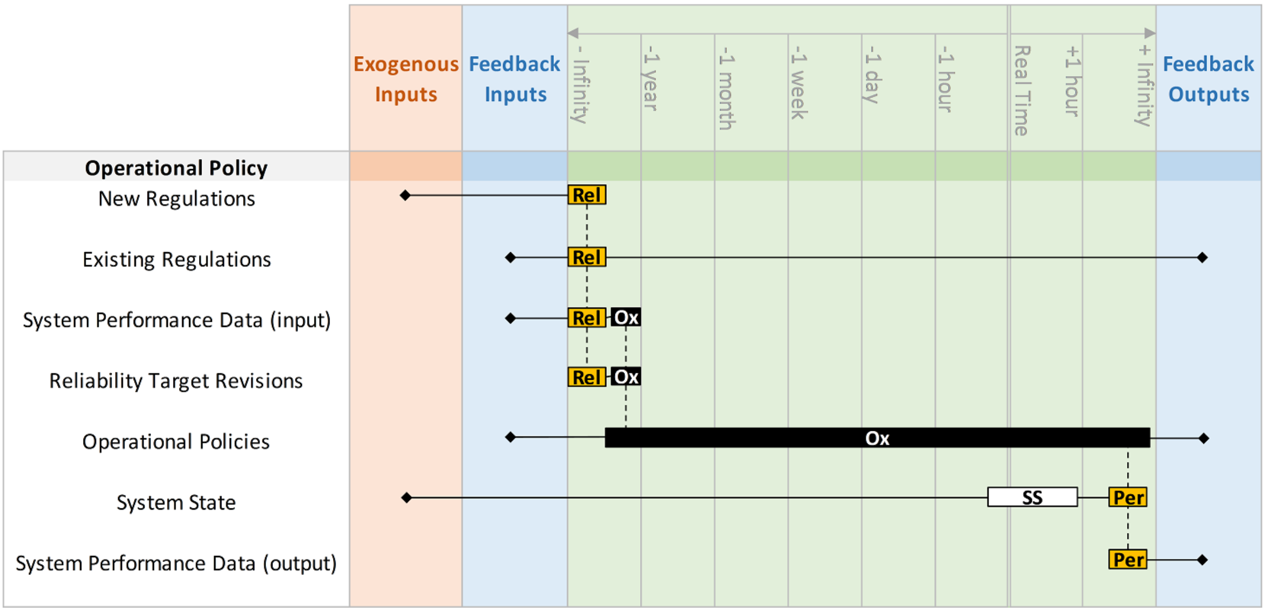

Figure 4.2: Operational Policy work flow (See Figure 4.1 for label definitions)

4.2.1 New Regulations

New regulations are changes to the performance requirements, set by a regulatory body, which the TSO is legally obliged to comply with. For most European TSOs these regulations will be the ENTSO-E network codes [ENTSO-E, 2015]. Network codes include constraints on reliability (e.g. compliance with the N-1 criterion), and expected quality and reach of service (e.g. acceptable voltage ranges for reference voltages) [ENTSO-E, 2013d]. The relevance of the network codes to reliability assessment is discussed further in GARPUR D1.2 [GARPUR, 2014c]. This task is shown as an exogenous input as regulatory bodies act independently, even though TSOs can provide recommendations to the regulatory body. This is in line with the typical process found for the elaboration of most grid/network codes.

4.2.2 Existing Regulations

The existing regulations are a perpetual input to the management of System Operations, and are revised when new regulations are enacted. They are a perpetual input to the policy creation task, as they describe the legal boundaries within which the TSO must operate. This is task has a feedback input and output to show that the application of regulations depends on how they were interpreted previously.

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4.2.3 System Performance Data (input)

This task defines a feedback input item (connected to System Performance Data (output)), showing where historical system performance data is used to inform the revision of reliability targets in the workflow, as well its use in revising operational policies. That is, the system performance data is used to check that the reliability targets and operational policies satisfy the performance requirements set by the regulations. At this decision level the System Performance Data usually consists of general performance measurements such as frequency of supply interruptions, duration of interruptions, Energy Not Supplied (ENS), Value of Lost Load (VOLL), or system losses.

4.2.4 Reliability Target Revisions

Comparison of system performance data with existing regulations may result in the revision of reliability targets. If previous reliability targets failed to meet regulations, they are revised to more conservative targets, and if the targets are inefficiently conservative the reliability targets may be relaxed. Reliability targets in this context largely refer to an objective that the TSO aims to minimize in addition to maintaining compliance with the reliability criteria. This may take the form of a stricter interpretation of the regulated constraints (e.g. adopting N-2 when only N-1 is regulated) or by using alternate objective functions that are constrained by the regulations (e.g. aiming to reduce the consequences of some higher order contingencies in addition to satisfying the N-1 criterion). The targets used by TSOs are largely based upon the targets set in their regulations.

4.2.5 Operational Policies

Given some change to the reliability targets (either due to changing regulations or due to changes in system performance targets), the operational policies of the TSO may also be revised. Most European TSOs (members of the Regional Group Continental Europe) are bound by a multilateral agreement to comply with the ENTSO-E Operational Handbook, which consists of a set of eight policies [ENTSO-E, 2014b]. In general, operational policies refer to the procedures and methods followed by the TSO, such as the timing of individual tasks, requirements for data retention, or task specific procedures. They govern the details of the tasks shown in the other workflow diagrams discussed in this chapter. Operational policies also include a set of (corrective and preventive) procedures that detail how system operators are to respond to common system faults. These procedures may be informed by a risk assessment, or based upon operator expert judgement.

4.2.6 System State

In all diagrams in Section 4, the ‘System State’ refers to the observed state of the bulk power system. This includes the following:

- The general ENTSO-E definition of System State (Normal, Alert, Emergency, Blackout, Restoration) [ENTSO-E, 2013d]
- Observed real-time system variables (Discussed in Section 3.1)
- Estimated system variables
- Forecasts of future system and exogenous variables
- Present planned actions
- Expectations on asset reliability

It should be noted that the system state perceived by the operator is not perfect, given the need to estimate some system variables periodically. The accuracy of the information provided by the state estimation is assessed on-line. Trust/quality indicators for the state estimation are normally presented to the operator. The possibility of error in the state estimation also poses a risk to real time operation.

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Regulations, reliability targets and operational policies do not directly affect the system state, as shown by the lack of links between these tasks and the system state on the workflow diagram above. These items affect the system state indirectly through other work flows, which is apparent by the inclusion of operational policies as the primary input to most other work flow diagrams (in the remaining sections in chapter 4). For example, a change in policy may result in an action that was previously acceptable to be rendered unacceptable. The policy itself isn't directly altering the physical state of the system, but instead indirectly affects it through restricting/allowing direct actions over a long time period.

The system state however affects the setting of reliability targets, through the system performance data. The system state is shown on all diagrams as having an exogenous input, as the instantaneous possibility of component failure is always present, as is the possibility of unexpected change in demand, supply, or some other uncontrolled influence of the system.

4.2.7 System Performance Data (Output)

Measurements of system performance are recorded and stored, which are then used to determine the adequacy of previous reliability targets. The data collected, and the temporal resolution of this data, is defined by the operational policies. The specifics of data collection, use and storage are covered in more detail in Chapter 5.

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4.3 Forecasting

Forecasting refers to the spatial-temporal prediction of electrical supply and demand in the bulk power system by the use of mathematical models. These predictions are used to forecast load-generation balance, and to forecast system power flow, component loading, and congestions. These latter forecasts are used as inputs to other workflows, and they form the basis from which TSOs plan most of their activities. Similarly to operational policies, forecasts do not affect the system state directly. The forecasting activities themselves are not all within the scope of System Operations, but they are shown in this report as they are all important inputs to other System Operations tasks, and they describe significant risks that affect real-time operation.

The forecasting process is described by the work flow diagram below in Figure 4.3. The diagram itself describes when forecasting models are used to generate forecasts (mainly for weather, supply, and demand), and how they define the main input for the System Operation tasks of forecasting congestion and the buying of losses. The workflow diagram also shows that forecast models are regularly updated by previous system performance data and assessments of forecast error. The individual line items are discussed in more detail after the diagram.

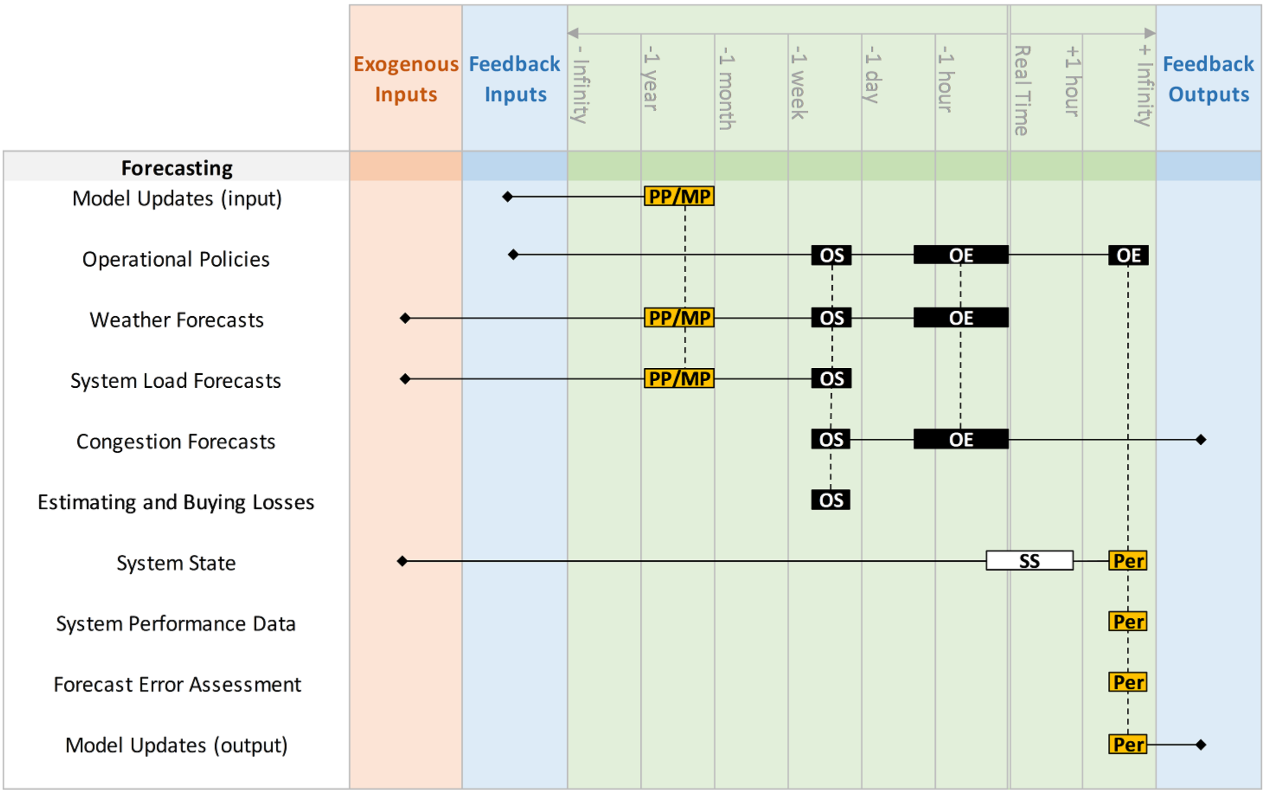

Figure 4.3: Forecasting workflow (See Figure 4.1 for label definitions)

4.3.1 Model Updates (input)

All forecasts are based on computational models which use historical data, numerical weather reports, and information about future timeframes (week, week-ends, statement of availabilities of power plants, market information etc.). The accuracy of forecasting models is assessed and revised after real-time operation (shown by the Model Updates (output) task on the figure above). This particular task shows where the assessment acts as an input to the workflow to improve future forecasts.

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4.3.2 Operational Policies

In this context, the operational policies define the TSO-specific procedures for the generation of all forecasts performed within the Systems Operation context, all contingency analyses, and the collection of system performance data and updating of models.

4.3.3 Weather Forecasts

Weather forecasts are normally provided by a bureau of meteorology, and describe an exogenous input to transmission system operations. Weather forecasts are used to refine the system load forecasts, and to generate shorter-term forecasts (less than a week ahead) such that scheduled outages and operations can be adjusted to ensure reliable system operation, and to anticipate bad weather risks. Weather forecasting also includes forecasts of wind and cloud cover, which is used in the System Load Forecasts (below) and for the forecasting of renewable energy production.

4.3.4 System Load Forecasts

The system load forecasts describe the nodal supply and demand, and hence can be used to forecast the system load, over a given period of time. This also includes the forecasting of renewable energy production by using the wind and cloud cover forecasts from the weather forecasting task discussed above. These are largely used for the planning and scheduling of outage works, in order to ensure adequate grid operation during outages. These forecasts are also used to plan inter-area capacities, market clearance, and the setting of tap-changer positions. Prior to the availability of weather forecasts, the system load forecasts exist as scenarios, as discussed in [GARPUR, 2015a] and [GARPUR, 2015b].

Most TSOs in the GARPUR reference group adjust demand forecasts up until real-time or a few hours before, using in-house proprietary software. TSOs also identified that they do not use the uncertainty measurements provided by their load forecasts for operational planning or decision making.

4.3.5 Congestion Forecasts

The congestion forecasts are based on the merging and balancing of TSO specific shorter-term models. The most common congestion forecasts are two days ahead (D2CF), one day ahead (DACF), and intraday forecasts (IDCF). The Congestion Forecasts are communicated to other TSOs, as well as regional organisations like TSC[4] and Coreso[5], to estimate cross-border and cross-market congestions and to anticipate regional risks. The timing of this task is specified by the market, maintenance and disconnection scheduling, and by the synchronous zone within which the TSO operates. This item also has inputs based on network capacity assessments, which is shown on the workflow diagram in the next section.

Intra-day forecasts are those which aim to accurately describe changes in supply and demand expected within a particular day of operation, with a fine resolution (between 5 and 60 minutes) and a lead-time of 1 to 23 hours. The intra-day forecasts are used to inform balancing markets. The intra-day forecasts may also be used to revise outage schedules, perform N-1 criteria assessments, revise day-ahead remedial actions, and to pre-emptively activate reserves.

[4] www.tscnet.eu
[5] www.coreso.eu

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A contingency analysis is required for the creation of day-ahead congestion forecasts and the intra-day forecasts. Given weather forecasts and nodal supply and demand forecasts (including RES generation), a contingency analysis must be used in order to ensure that the congestion forecasts and intra-day forecasts describe a system that operates both securely and adequately.

4.3.6 Estimating and Buying Losses

The estimation and buying of losses may occur after the creation of day-ahead congestion forecasts. In some cases the TSO estimates and buys losses at longer time-scales, either weeks in advance or even procured annually [EGREG, 2008]. In this context, losses refer to energy that is physically dissipated from the system during transmission (e.g., heat losses, corona losses, transformer no load losses, and ancillary substation installation consumption).

4.3.7 System State

As is the case with operational policy, the forecasting procedure does not directly affect the system state. It indirectly affects the system by causing changes to the outage schedule, as well as by changing the nodal supply by informing the market of network capacities (based on forecasts), as well as reserves and the settings of power control devices (e.g. tap settings).

4.3.8 System Performance Data

As is the case in operational policy, the system performance data is used to check the accuracy of forecasts. The resolution of data collected is defined by the operational policies. This information is used to adapt operational policies.

4.3.9 Forecast Error Assessment

Given the historical record of forecasts and the system performance data, it is possible to assess the error (and hence accuracy) of the forecasting process. Substantial or predictable errors in forecasting are then used to refine and update models to improve future system loading forecasts.

4.3.10 Model Updates (out)

The previous assessment of forecast errors may result in some suggested improvements to the forecasting models. These updates result in a continuous refinement of the forecasting process. Given that these assessments are made after real-time operation, they must then act as an input (defined by the first task described in this figure) to affect future forecasts.

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4.4 Network Capacities

In the System Operations context, network capacities describe the technical congestions that limit the flow of power between nodes and regions on the grid. These capacities are communicated to the market, which then result in a capacity constrained supply of electricity. In general areas that are commonly separated due to congestion are defined as price areas over the long-term (e.g., the five price areas in the Norwegian transmission system). Transmission capacities between areas are communicated to the market a day ahead of schedule, which informs the market prior to clearance. This clearance results in a forecast of expected congestions which may or may not be realised, and is also used to inform intra-day forecasts.

The network capacity tasks do not directly affect the system state, as was the case in the previous two sub-sections. The system state is affected indirectly through the market clearance and via the intra-day forecasting. The network capacity process is described by the work flow diagram below in Figure 4.4. The individual line items are discussed in more detail after the diagram.

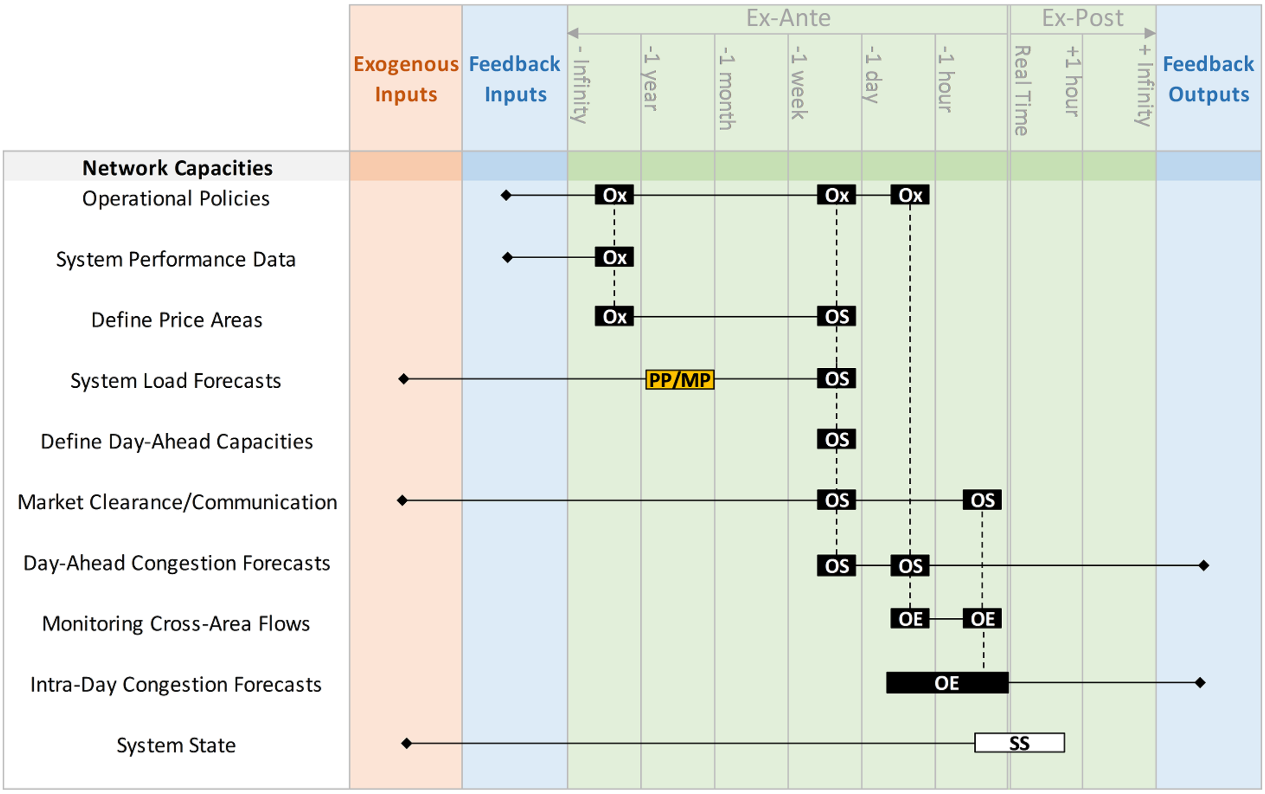

Figure 4.4: Network Capacities workflow (See Figure 4.1 for label definitions)

4.4.1 Operational Policies

The operational policies in this context relate to the procedure used to define price areas within the TSO's area of responsibility, as well as the procedures for calculating inter-area and day-ahead capacities, and for undertaking market clearance and communication.

4.4.2 System Performance Data

The long-term system performance data is used as input to the definition of price areas, as price areas are defined by long-term trends of congestion between two areas.

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4.4.3 Define Price Areas

The price areas are defined based on some historical congestion between two defined areas within the transmission system, and in accordance with operational policies. The workflow diagram shows that these price areas are only defined for time scales for longer than a year, but it is possible that some TSOs change price areas on a shorter time scale (due to seasonal variation within their grid).

4.4.4 System Load Forecasts

After price areas have been defined, the system load forecasts are used as an input for the calculation of day-ahead capacities between price areas.

4.4.5 Define Day-Ahead Capacities

The day-ahead capacities are calculated using the day-ahead congestion forecasts (DACF). These define the constraints on line loading between two price areas, which will cause a market split once the capacity has been reached.

4.4.6 Market Clearing/Communication

The day-ahead capacities are communicated to the market as well as other TSOs, resulting in a market clearing level of supply (based on the merit order list) that is constrained by cross-border transmission capacities. Presently, markets are coupled using the Available Transmission Capacity (ATC) mechanism, in which TSOs calculate internal constraints on cross-border flows based on DC power flow and N-1 assessments. For two neighbouring TSOs, the minimum cross-border flow calculated using ATC is taken to be the constraint on cross-border flow.

Flow-based (FB) capacity mechanisms provide an alternative to ATC mechanisms. FB mechanisms differ from the ATC method in that the cross-border flows are calculated using a shared, regional DC power flow model and N-1 security analysis (instead of TSOs calculating separate constraints).

4.4.7 Day-Ahead Congestion Forecasts

The day-ahead congestion forecasts are explained in Section 4.3. This task is repeated on this figure as the definition of price areas and the market clearance are key inputs to the eventual calculation of the day-ahead congestion forecasts. This task may also implicitly include an N-1 risk assessment.

4.4.8 Monitoring Cross-Area Flows

The lines that are likely to experience congestion in the day ahead are monitored closely, and this monitoring is used to adjust intra-day forecasts, and hence inform the decision making process of system operators.

4.4.9 Intra-Day Congestion Forecasts

The monitoring of the cross-area flows informs the intra-day forecasts, as a congestion event affects both sides of the congested transmission line. The intra-day forecasts are explained in Section 4.3.

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4.4.10 System State

As with the previous two sections (4.2 and 4.3), the decisions made, and tasks performed, in the network capacity workflow does not affect the system state directly. They indirectly affect the system state through the market clearance, based upon the definition of price areas.

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4.5 Outage Execution

From the answers to questionnaire completed by TSOs, the workflow for outage scheduling is ranging from mid-term operational planning to short-term operational planning. This workflow describes the creation of an outage schedule given some previously generated outage plan, and based on new system, weather, and congestion forecasts. The outage schedule is liable to be revised up until real-time operation, given the possibility of emergency requests or unexpected changes to system operation. The outage schedule defines the grid topology, specifically which elements are out of operation due to required maintenance or system development work. The decisions made in this workflow also implicitly consider the outages of elements in the N-1 contingency analysis task. The decisions made in the outage scheduling process directly impact the state of the system through the setting of circuit breakers. Notice that the development of the outage plan is covered by GARPUR deliverable D5.1 [GARPUR, 2015a], which concentrates on asset management, and is therefore not discussed in detail in this report.

The scheduling of outages is also a scheduling of risk, as any outage increases the risk of a loss of load in the system. That is, removing a transmission line from operation reduces the level of redundancy for nearby lines, whilst also increasing the load on nearby lines. The Outage Execution process is described by the work flow diagram below in Figure 4.5. The individual items, related to the short-term part of the operational planning and to the real-time operation, are discussed in more detail after the diagram.

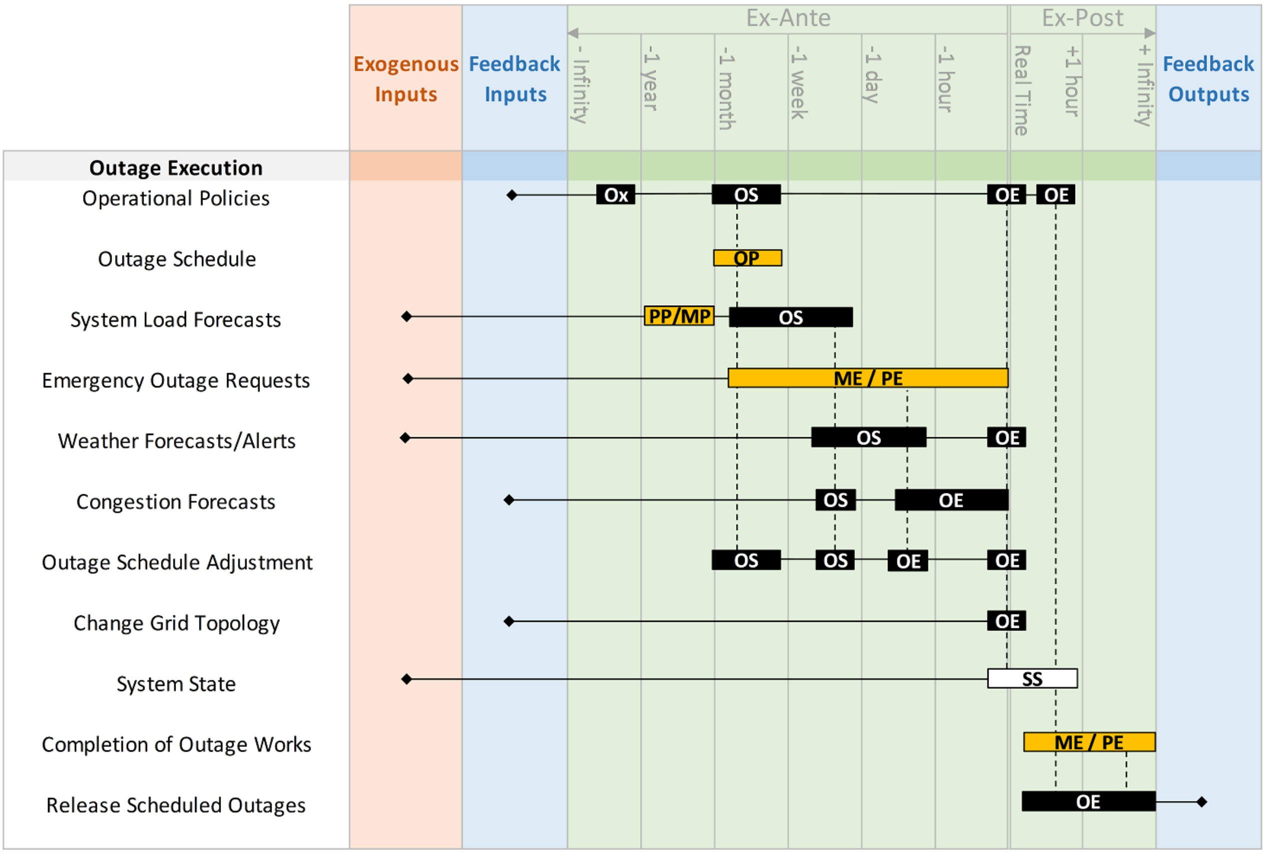

Figure 4.5: Outage Execution workflow (See Figure 4.1 for label definitions)

4.5.1 Operational Policies

In the context of Outage Scheduling, the operational policies describe the procedure for generating the schedule, performing contingency analyses, switching circuit breakers, and the releasing of scheduled

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outage works. The present day operational procedures for undertaking outages have multiple levels of redundancy in order to minimize the potential for human error, and are therefore a risk management tool.

4.5.2 Outage Schedule

The outage schedule is an input from the asset management workflow, described by GARPUR deliverable D5.1 [GARPUR, 2015a]. This schedule describes the organisation of specific maintenance and system development tasks within specific time frames (less than a month). This schedule is based on a more general, long-term outage plan. The Outage Execution workflow is tasked with ensuring the scheduled outages occur in a way that maintains the expected level of system reliability within the short-term operational horizon.

4.5.3 System Load Forecasts

The system load forecasts, discussed in Section 4.3 describe the nodal supply/demand. This is used as an input in the contingency analysis of the system. This contingency analysis forms the basis for future adjustments of the outage schedule to ensure secure and adequate operation during outages.

4.5.4 Emergency Outage Requests

Maintenance and project development activities are generally planned in a time frame of months or even years in advance of system operation. However, emergency works may be requested at shorter notice, due to changes to the system (e.g. specifically component failures or unscheduled loss of generation infrastructure). Similarly, outage works can be cancelled at short notice. This affects the outage schedule, requiring adjustment of the outage schedule at shorter time frames. In the context of System Operations these emergency outage requests can be considered as an exogenous variable.

4.5.5 Weather Forecasts/Alerts

Weather forecasts (1 to 2 weeks ahead) and alerts (hours to days ahead) inform the TSO of exogenous risks to the transmission system, and therefore must be included as an input to the contingency analyses that occur in these time frames. The weather forecasts also include adjustments regarding the expected supply from renewable energy generators (i.e. forecasts of wind speeds and hourly output of wind farms). The survey sent to the GARPUR reference group suggests that RES production is first forecasted between a week to three days ahead of time, and forecasts are adjusted regularly up until a few hours before dispatch or until real-time.

4.5.6 Congestion Forecasts

The congestion forecasts may be used to revise the outage schedule, given some unforeseen congestions, a day prior to the scheduled activities occurring. This includes both DACF and IDCF forecasts. The congestion forecasts may identify the need to delay, or the opportunity to bring forward, scheduled outages.

4.5.7 Outage Schedule (and revisions)

The outage schedule, which defines precisely when outage tasks are to occur and for how long they are to last, is progressively adjusted by applying an N-1 contingency analysis to ensure secure system operation. The first revision of the outage schedule occurs weeks to months in advance of the scheduled tasks. The schedule is then refined progressively (based on the specific operational policy of the TSO) as more detailed forecasts are made, and as the operational state of the system becomes more certain. A

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survey sent to TSOs within the reference group for the GARPUR project showed that the final approval for outages due to maintenance occurs anywhere between 4 days to a number of weeks in advance of the planned date. Additionally, some TSOs stated that they are able to interrupt or cancel maintenance work when required (to maintain system reliability).

As mentioned at the start of this section, the outage schedule has an implicit trade-off of an outage increasing short-term system risk versus a long-term gain in reliability after the outage has occurred. The requirement that the system must be N-1 secure at all times may result in outage work being postponed to a later period, or alternatively, may result in opportunistic outages (e.g. an outage of a major load may provide an opportunity to perform maintenance on lines that would otherwise be too heavily loaded). This possibility to cancel or delay maintenance work at short notice is shown as a loop output.

4.5.8 Change Grid Topology

The outage schedule is used to define which outages can occur without causing the system to violate the N-1 criterion, and hence will result in the operator changing the substation operational arrangements (and hence switchgears, couplings, etc.) to enforce these outages. This causes a change in grid topology, which is a physical change to the system state (as shown on the workflow diagram).

4.5.9 System State

The system state is directly affected by the outage schedule workflow through the changing of circuit breaker positions, and hence by the changing topology of the transmission system. The changing of grid topology results in a change to the actual system reliability.

4.5.10 Completion of Outage Works

The outage works themselves occur after the required switching of circuit breakers has occurred. The duration of the outage works is task specific, and also depends upon the TSO specific procedures. The completion of outage works is not a System Operations task, but it should be noted that the reliability of the system can be affected whilst the outage tasks are occurring (due to human error) as well as after.

4.5.11 Release Scheduled Outages

Once outage works have been completed, the line outages are no longer required, and the previous change to grid topology can be reversed. This affects the actual system reliability in two ways. First, the return of a line, or multiple lines, to operation improves system reliability. Second, maintenance and system development work also affects reliability. Therefore, the duration and possibility of delay, of outage works is a key part of reliability calculations. In some cases restitution delays may be required, where maintenance work is interrupted to bring a component back into operation to prevent the system risk from entering an alert or emergency state, with work to be completed at a later date.

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4.6 Reserve Management

The Reserve Management process covers the procedure of contracting long-term reserves, the commitment of generators to act as reserves for a particular period, the activation of reserves, and the settlement of reserves. It is assumed that all of these tasks can be considered as System Operations tasks, however some TSOs may describe the contracting of new reserves as a System Development task. In the context of System Operations, reserves are back-up generators which are organised such that the system's real and reactive power supply meets the N-1 criterion. Reserves are divided into three categories, Frequency Containment Reserves (FCR), and Automatic and Manual Frequency Restoration Reserves (FRR-A and FRR-M), in order of activation priority [ENTSO-E, 2012]. These items are discussed in more detail towards the end of this sub-section.

The main goal of reserve management is to ensure an adequate quantity of reserves is available for a given period of time. Inadequate reserves may occur due to inadequate capacity on the reserve market, a failure to commit enough reserves for a given period, or an unexpected failure of reserves when required. The Reserve Management process is described by the detailed work flow diagram below in Figure 4.6. The individual line items are discussed in more detail after the diagram.

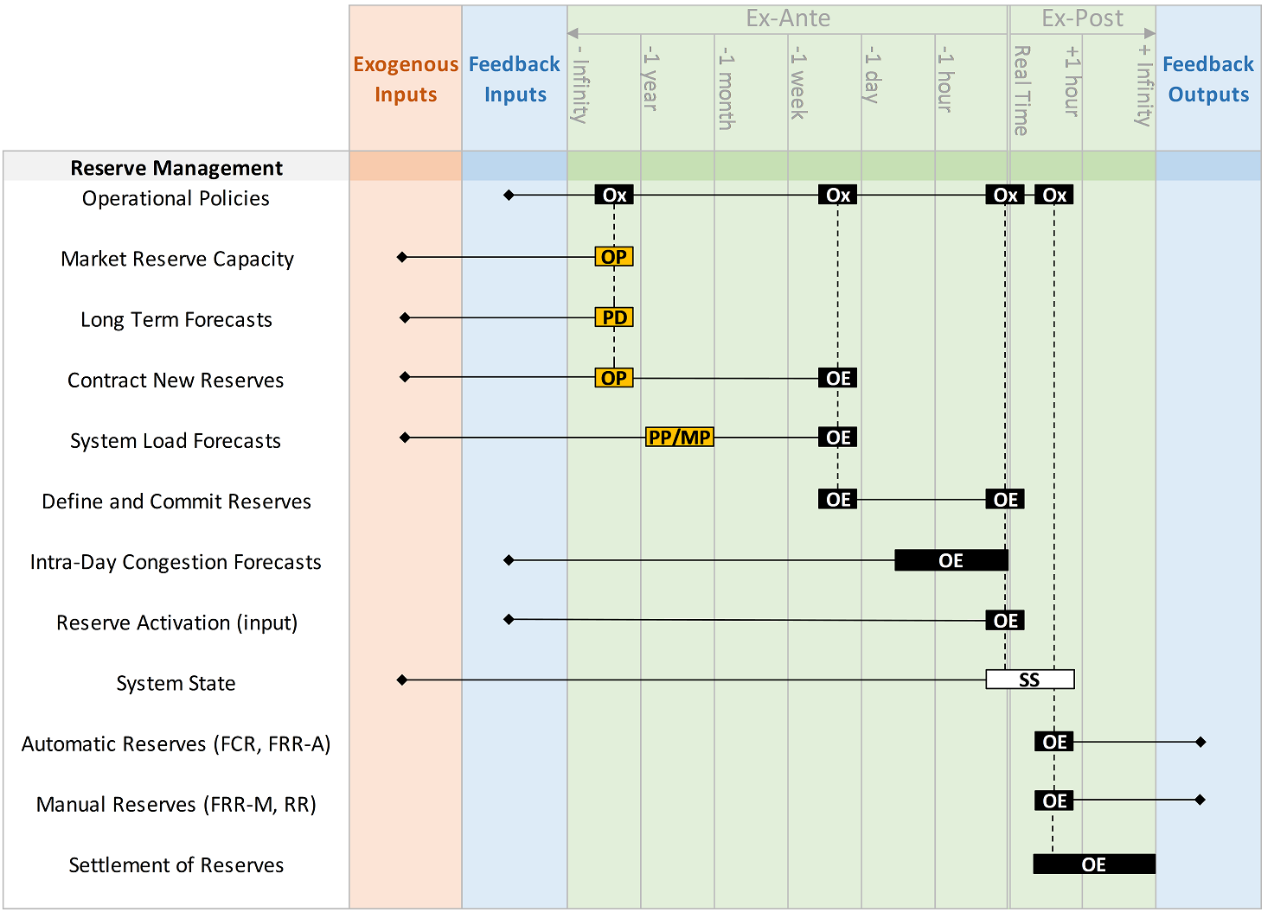

Figure 4.6: Reserve Management workflow (See Figure 4.1 for label definitions)

4.6.1 Existing Policies

In the context of Reserve Management the operational policies govern the contracting of new reserves, the commission of reserve generators, the activation of reserves, and the settlement of reserves after their activation. It is through the policies that some level of system risk is defined as acceptable.

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4.6.2 Market Reserve Capacity

The installed power supply capacity on the market is not directly controlled by the TSO (TSOs do not own or directly commission the generators that act as reserve power), and therefore it is shown as an initial exogenous input. The installed capacity defines the primary constraint on the contracting of new reserves, and hence the security of the system.

4.6.3 Long-Term Forecasts

The proportion of reserve capacity required on the transmission system is largely defined by regulation and operational policy, but long-term forecasts are required to inform the spatial and temporal requirements of specific generators as reserves.

4.6.4 Contract New Reserves

The contracting of new reserves depends on the capability of the market to supply reserve generators and the requirements of the system defined by regulations, policy and long-term forecasts. Based on this information new reserves can be contracted. This task may involve a contingency analysis in order to ensure that the allocation of reserves meet the N-1 criterion. This is shown as having an exogenous input as the specification of generators for activation isn't provided by the retailer until a day in advance.

4.6.5 System Load Forecasts

The system load forecasts, described in Section 4.2, are used as input for the commission of particular reserves as FCR, FRR-A, FRR-M, or RR.

4.6.6 Define and Commit Reserves

For a given operational period, the reserves must be defined as either FCR, FRR-A, FRR-M or RR, and confirmed with the specific generators. This is based on a short-term risk assessment to define the quantity of each type of reserve required to ensure grid security, and where these reserves should be located. Again, this risk assessment is based on the N-1 criterion, and on additional requirements defined by regulations. The ability of a particular generator to act as a particular type of reserve depends on their quickness of activation, capacity and their duration of availability. For some TSOs this tasks is implicitly included in the contracting of new reserves. This depends entirely upon whether the TSO contracts reserves on long-term contracts, or via a reserves market.

Some generators, specifically renewables, may be defined by special contracts to limit their production in a given period in order to prevent congestion. This 'dispatchable' load can be defined as a reserve, as it is used to adjust power flows in the electrical system. Additionally, reactive reserve generators may also be committed for one or more market periods to some reactive set-point.

4.6.7 Intra-day Congestion Forecasts

The intra-day congestion forecasts, described in Sections 4.2 and 4.3, may be used as an input for the activation of reserves. That is, the intra-day forecasts are used to define periods in which the supply settled on the day-ahead market or the balancing market is unlikely to meet the demand, and therefore the use of reserves can be scheduled in anticipation.

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4.6.8 Reserve Activation

This task refers to the activation of reserves given some previous decision to activate them, or due to a scheduled activation of reserves based on the intra-day forecasts. The automatic and manual reserves are discussed after the system state below (as they are corrective actions). The priority of activating one reserve over another depends primarily on type of reserve (i.e. automatic reserves will activate before manual reserves) and then depends upon price merit order. In some special cases where there is a power flow problem reserves will be activated based on their proximity to the deficient part of the system. It should also be noted that some TSOs noted the possibility of activating cross-border reserves, in a survey of the GARPUR reference group.

4.6.9 System State

The activation of reserves directly affects the system state, given that changing supply on a particular node affects the load flows in the vicinity of that node, and hence affects the system reliability. Additionally, the system state acts as an input for the activation of automatic and manual reserves. This is due to the activation of reserves occurring when the apparent system state deviates from an expected system state.

4.6.10 Automatic Reserves (FCR, FRR-A)

This refers to the activation of frequency containment reserves (FCR) and automatic frequency restoration reserves (FRR-A) which occur automatically in order to contain and to partially restore instantaneous frequency fluctuations and small short-term deviations from the scheduled market production, respectively. The time required for the automatic system to react to the system state and to activate/deactivate automatic reserves can range from 0 seconds to 15 minutes. The process itself is automated, but there is an internal task of assessing the performance of the automated system and setting the system rules such that the reserves are activated optimally (both temporally and spatially). The process therefore must be supervised and adjusted to ensure adequate operation.

4.6.11 Manual Reserves (FRR-M, RR)

In the case of large deviations from the expected production (or demand) of power beyond the control capabilities of the automated reserve system, there exist manual frequency restoration reserves (FRR-M) which are used to restore the system frequency. In addition, the original availability of the FRR-A must be restored once activated, which is achieved by manually activating replacement reserves (RR). Depending on the TSO strategy, this task also requires a short-term risk assessment of the system by the operator to determine the appropriate adjustment to reserves to ensure grid reliability is maintained. The process of activating manual reserves is generally defined in the operational policies and procedures. In some cases TSOs may define interruptible loads as manual reserves.

4.6.12 Settlement of Reserves

At some point after the activation of reserves, the cost of reserves must be settled with the generators, at the cost of the TSO. This task does not directly affect system reliability, but obviously the cost of reserves is proportional to the perceived risk of the system. Therefore this could be perceived as an indirect cost of some risk management framework.

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4.7 Voltage control

This workflow specifically deals with maintaining secure voltage levels across the transmission system. The majority of voltage control actions occur in real-time, given some unexpected deviations of voltage. Voltage control actions can be split into three parts. These are:

i) The automated voltage control actions based upon optimal power flow analysis (changing reactive power generation, setting of transformer tap positions, switching on/off shunt reactors and other reactive compensation devices);

ii) Setting requested voltages on TSO/DSO borders or setting reactive power limits on TSO/TSO lines or corridors;

iii) Manual regulation of transformer tap changers.

The Voltage Control process is described by the detailed work flow diagram below in Figure 4.7. The items listed on the workflow diagram after the System State are listed in their general order of priority. That is, altering the settings of reactive compensation devices is the most favourable voltage control action, while curtailing load is the least favourable. The individual line items are discussed in more detail after the diagram.

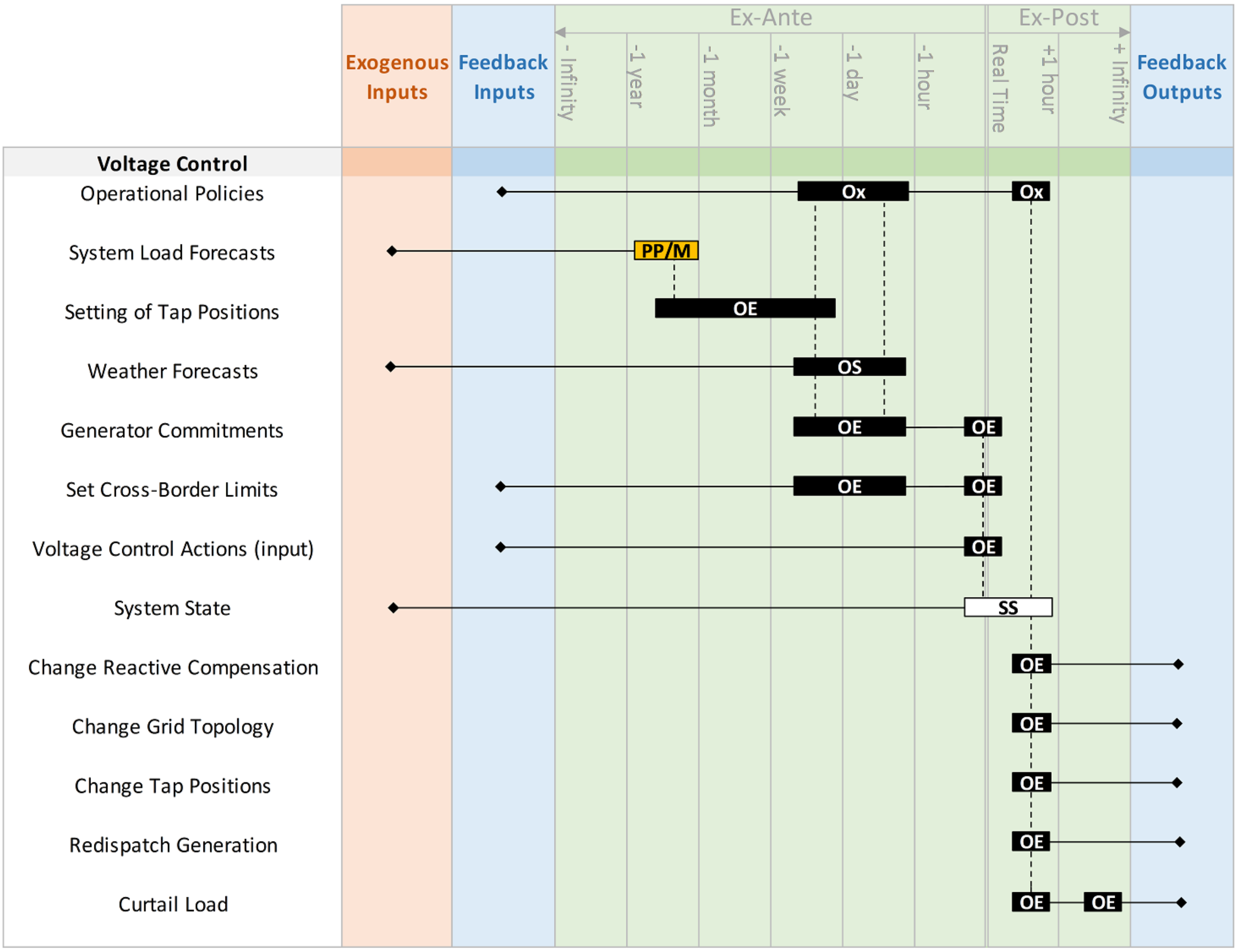

Figure 4.7: Voltage Control workflow (See Figure 4.1 for label definitions)

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4.7.1 Operational Policies

In the context of Voltage Control processes the operational policies define the procedure for setting tap changer positions, generator commitments to provide reactive power, and the operator specific actions to control Voltage.

4.7.2 System Load Forecasts

System load forecasts are used as an input to the setting of transformer tap-changer positions, and are discussed in more detail in Section 4.2. The expected nodal supply/demand can be used to estimate the voltages at each node in the system, and hence to determine whether a particular loading scenario is stable.

4.7.3 Setting of Tap Positions

The tap position of transformers may be manually set between a day and a year before some realised system state. The decision to change a tap-changer position is based upon the system load forecasts, which predict the nodal voltages during some future operational scenarios. This decision is made by the System Operations team, in order to maintain the required voltage. The decisions available in this task are obviously constrained by the infrastructure available.

4.7.4 Weather Forecasts

Weather forecasts are used as input to the commitment of generators to provide reactive power, as wind farm generation and load characteristics are highly weather dependent.

4.7.5 Generator Commitments

Generators that have reactive power capability are committed to control the voltage at specific nodes, in advance of voltage issues. That is, some generators are committed to act as reactive power reserve for some specified time period. That is, generators can be committed to a control scheme that forces them to operate at a fixed voltage, reactive power output, or power angle, and therefore may automatically compensate for changes in the system. The system load forecasts and weather forecasts are used to determine the required commitment level of generators. This task requires an assessment of the expected requirement for reactive power compensation on the transmission system to ensure adequate voltage levels. This task may also include SVCs and FACTS devices, which have specific capacities and continuous control.

4.7.6 Set Cross-Border Limits

Changes to the active and reactive power limits on TSO and DSO connections can be requested, depending on contracts, such that the voltages within the control area are maintained within some required limit.

4.7.7 Voltage Control Actions (input)

This task describes the activation of either manual or automatic voltage control to correct the voltage at one or more points on the system. That is, the decision to affect the voltage is made after a system state, but the action itself occurs in real time and affects the future system state. In the time frame of an hour ahead (up to real time), the operator will set a fixed reactive power set-point for generators that have been committed to reactive power control. Generators that have been set to voltage droop control will

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automatically adjust reactive power output (when required) to maintain the required voltage at their connection point.

4.7.8 System State

As stated above, the voltage control actions (discussed after this item) directly affect the system state. By altering the state of transformers, generators and reactive compensation devices, the nodal supply and the power flows are affected directly, and hence voltage can be controlled and voltage collapse can be prevented.

4.7.9 Change Reactive Compensation

Reactive compensation can be altered automatically in order to provide reactive power compensation and to adjust the voltage at specific nodes, by setting some generators, SVCs and FACTS devices to some operational set-point based on a pilot node. Other devices, such as tap-changer positions and capacitor bank connections are generally managed manually via the control room, using a decision-supporting tool that is based on the state estimator and an OPF.

4.7.10 Change Grid Topology

The voltages on the system are a direct result of the nodal supply and demand, as well as the topology of the system. Therefore it may be possible to resolve voltage issues by changing the grid topology (i.e. switching breakers, coupler settings, bus connections, etc.).

4.7.11 Change Tap Positions

As with reactive compensation devices, tap-changer positions can be altered either manually or automatically. Altering tap-changer positions can reduce loop flows between transformers.

4.7.12 Redispatch Generation

Voltage collapse may be avoided by shifting power supply from one location to another, at some cost. Additionally, some generators have the ability to provide some level of reactive power generation, which can be used to provide reactive compensation and to alter the voltage at specific nodes. This occurs at the loss of some real power generation, which must be accounted for by increasing production elsewhere.

4.7.13 Curtail Load

If the previous actions cannot prevent unsafe voltages from occurring on the system (specifically voltage collapse) then the curtailing of load (brownouts) may be required in order to maintain an acceptable level of system security and to avoid significant voltage collapse. This may also include the blocking of distribution transformer taps.

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4.8 Control of Component Loading

This process is largely concerned with keeping the power flows through transmission system components at acceptable levels, specifically to prevent technical faults from occurring. This process largely requires knowledge of the health of individual components to be passed from Asset Management tasks to the System Operation workflow. The loading limits are based upon some procedural health assessment of components, and are maintained by constant monitoring and load management.

The main risk associated with this workflow is the overloading of lines due to misjudging the health of components. This risk is generally mitigated by setting static loading limits of components. Additionally, components may have dynamic loading limits, either defined by the weather (colder weather may allow for higher line loading) or by temporal periods (allowing transformers to be overloaded for short periods). The Component Loading Control process is described by the detailed workflow diagram below in Figure 4.8. The individual line items are discussed in more detail after the diagram.

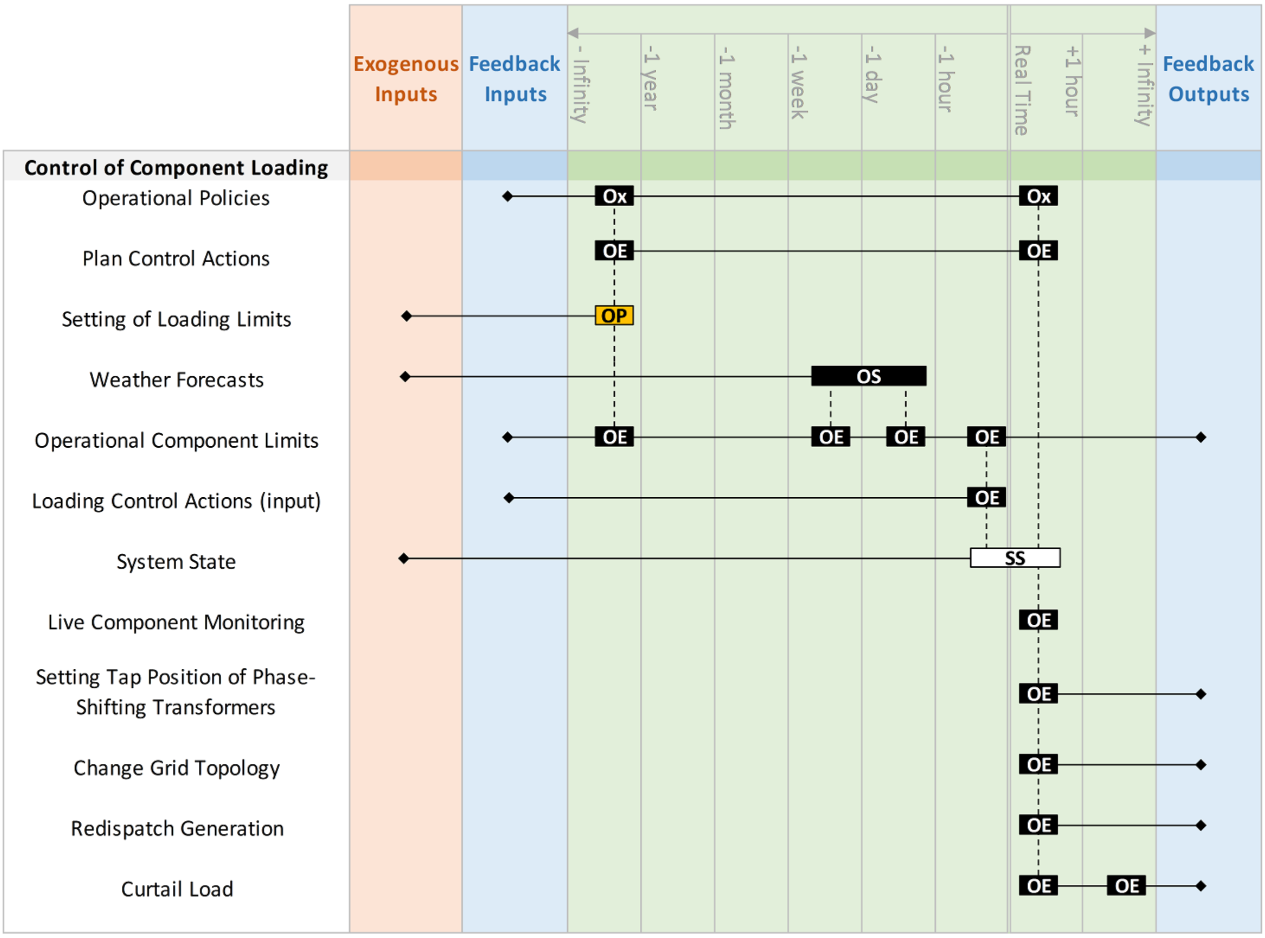

Figure 4.8: Component Loading Control workflow (See Figure 4.1 for label definitions)

4.8.1 Operational Policies

In the context of controlling component loading, operational policies define the procedure for setting loading limits, the planning of control actions (i.e. in which situations are specific responses acceptable), and the procedures for the specific operator actions.

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4.8.2 Plan Control Actions

The control actions specify the options that the operator has in order to respond to an unacceptable level of component loading. The actions available to the operator also affect the setting of the limits themselves, as the ability of an operator to respond to a particular loading scenario must be considered when choosing an appropriate level of risk. It is also a necessity to anticipate corrective remedial actions and their duration.

4.8.3 Setting of Loading Limits

The Operation Policies define some maximum level of risk that can be taken regarding failure of components due to loading, which is then used to set some operational loading limits for all components. The limits also depend on external information regarding component specifications and expected operating conditions, as well as the maximum or minimum output of generator units (in the case of TSO's having direct control of units) and their ramping rates. The output of this task is a set of strict, quantifiable limits on component loading, which are then monitored. These loading limits define an upper constraint on the loading of components, which persist over a long time period (i.e. life of the component).

4.8.4 Weather Forecasts

It is possible for weather forecasts and alerts to trigger an increase or reduction of the temporary and steady state thermal ratings of grid components. Similarly weather conditions may be used to inform dynamic line ratings. It should be noted however that the use of dynamic line ratings varies among TSOs.

4.8.5 Operational Component Limits

As stated above, monitoring of components and weather forecasts may result in changes to the operational limits of components, either temporarily or permanently, and on any time scale. This also includes the use of thermal/dynamic line ratings. The operational component limits are those which are used to inform the system monitoring software, specifically alarms that notify the operator of components that are near their operational limits.

4.8.6 Loading Control Actions (input)

This task describes actions taken by the operator, after some decision, to correct the load flow at one or more points on the system. Specifically, it refers to the point in time where actions taken in Sections 4.8.8 to 4.8.12 enter the workflow in order to influence the future System State.

4.8.7 System State

As shown in the workflow diagram, the system state is directly affected by the loading control actions performed by the operator.

4.8.8 Live Component Monitoring

In order for operators to be aware of unacceptable component loadings, it is typical for TSOs to have an automatic monitoring system that alerts the operator of loading situations that are close to the defined component limits. These alarms signal to the operator that a loading control action may be required in the near future in order to preserve the integrity and the optimal utilisation of the component.

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4.8.9 Setting Tap Position of Phase-Shifting Transformers

Phase-shifting transformers can be adjusted in order to adjust the loading of grid elements. This is generally the preferred method of reducing line loading, as it comes at limited cost to the TSO (influence on system losses) or to the consumer (influence on market capacities).

4.8.10 Change Grid Topology

Grid topology can be changed by switching breakers, couplers or moving lines between bus bars (through no-load switches). Undesirable component loading can be avoided by changing grid topology, avoiding failure of critically loaded lines, and sending flow through lines with excess capacity. This action could also be combined with a decision to perform generation redispatch. This may also include the reversal of some planned outage for maintenance or development activities. Changing grid topology in order to correct for component loading may also influence system losses.

4.8.11 Redispatch Generation

Undesirable loading scenarios can also be avoided by shifting supply from one generator to another. This however comes at a cost to the TSO due to deviating from the market settled supply arrangement. This refers to both active and reserve generation.

4.8.12 Curtail Load

If the previous actions fail to avoid an undesirable loading scenario the TSO can modify the voltage set point of distribution transformers (e.g. U-5%) to influence active power consumption. Depending on the type of load (thermal, impedant, etc.) this action can only provide its results for a short period of time (1 to 2 hours). In addition, as the ultimate resort, non-priority load shedding can be performed at pre-defined nodes of the system, causing brownouts in order to avoid failures that may cascade into more serious blackout events.

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4.9 System Protection

System protection schemes define automated grid actions that respond to emergency state instabilities of the grid. An example of system protection is demand response, in which demand at a node is automatically reduced in response to a significant drop in voltage or frequency. Another example would be the automatic disconnection of lines in response to overloading, in order to protect components or to intentionally create islands on the grid to localise the consequences of faults or to prevent cascading faults. The System Protection process is described by the detailed workflow diagram below in Figure 4.9. The individual line items are discussed in more detail after the diagram.

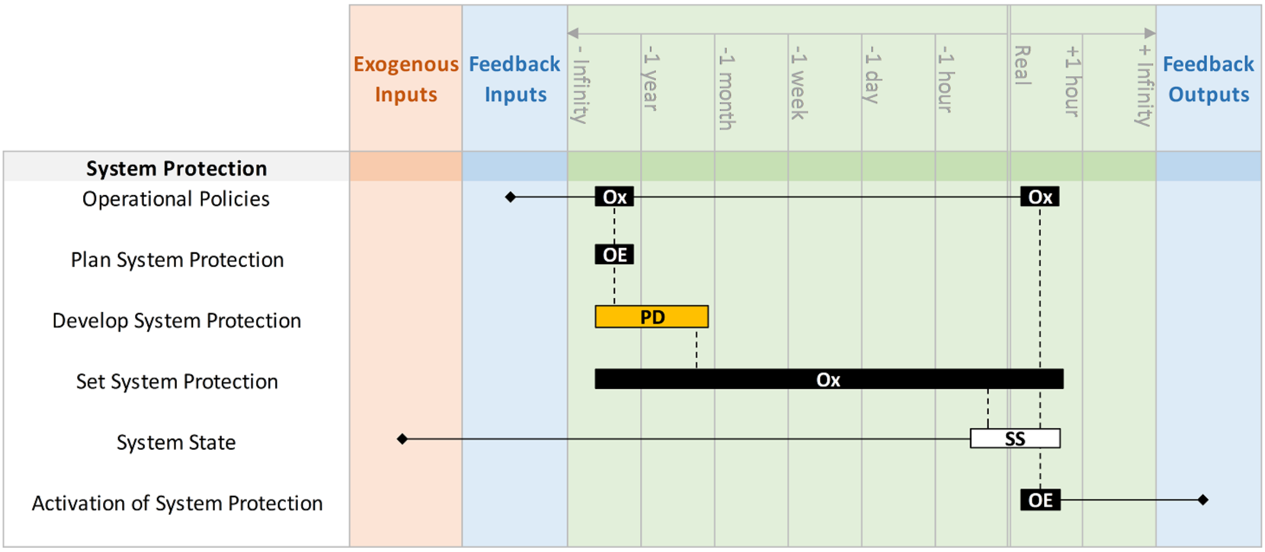

Figure 4.9: System Protection workflow (See Figure 4.1 for label definitions)

4.9.1 Operational Policies

In the context of system protection, operational policies dictate the planning and development of system protection devices, and the rules which govern when these system protection devices activate.

4.9.2 Plan System Protection

System protection is planned on the basis of satisfying existing Operating Policies. This involves a risk assessment of the present operation of the grid, assess the value added by new system protection units, and to determine the optimal level of system protection to ensure reliable grid operation.

4.9.3 Develop System Protection

The details of how investments in new grid infrastructure are assessed, approved and developed are covered in GARPUR deliverable D4.1. This specific task refers to the development of relays and other components required for system protection.

4.9.4 Set System Protection

The system protection units on the system must be set prior to their eventual activation when a contingency occurs. The setting of a system protection unit can be initialised or changed at any point in time from the construction of the system protection scheme to real time operation. This task involves the assessment of the required level of system protection, and setting the devices appropriately to react to any contingencies such that they increase reliability.

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4.9.5 System State

The system state is directly influenced by the triggering of system protection devices, based on the settings of the system protection devices discussed above.

4.9.6 Activation of System Protection

System protection schemes respond automatically to a contingency occurring on the system state, and affect the system state directly. This occurs without any input from the operator. The 'live component monitoring' task discussed in the loading control workflow diagram could also be considered as an input to this task.

4.10 Discussion

The workflow diagrams of the previous sections are general enough so that they cover the main tasks of TSOs, but at a loss of detail as to what happens in and around the control room. The specific procedures of TSOs depend largely upon the design of their system, and the regulatory and market environment within which they operate. For example, the operational procedures in an isolated country are different to those of a country in a multi-TSO meshed network. A TSO with a lot of renewable energy generators requires different processes to that of a TSO with very little or none. However the risks that are managed by TSOs, as well as control actions available to manage the risks, are fairly common to all TSOs but in varying degrees of importance. Therefore it is useful to discuss the risks and control actions available to TSOs, from the perspective of the workflow diagrams.

In the context of workflows, it is useful to discuss risk in terms of the tasks or events that introduce risk into the workflow process. These are defined on the above workflow diagrams as tasks that have some exogenous input. Table 4.1 below lists these tasks and events, as well as the time scale they affect, their main consequences, and their main method of control.

Table 4.1: Summary of the main risks associated with the System Operations workflow

Risk (relevant section)	Time scale	Consequence Description	Relative Severity	Relative Likelihood	Mitigation Method
New regulations (4.2.1)	Yrs	Changes operational targets, and constrains operational procedures	**Low** *TSOs may provide feedback on proposed changes*	**Low** *regulatory change is slow and infrequent*	Pre-emptively exceeding regulated performance criteria
New generation/load sources (4.3.3)	Yrs	Line/Substation construction requirements, Power flow changes	**Low** *System is likely to be developed to accommodate generation*	**Low** *Likely that risk will be managed by new grid projects*	Initial risk assessment of component load capabilities and adequate system development
Change in market reserve capacity (4.6.2)	Yrs	Changes reserve availability/adequacy	**Medium** *A reduction in reserve availability may seriously affect system reliability*	**Low** *Likely that risk will be noticed and managed prior to affecting System Operations*	Risk-averse approach to contracting reserves
Long term forecast error (4.6.5)	Yrs	Changes expected reserve requirement	**Medium** *May result in inadequate reserve procurement*	**Low** *Errors are likely to be noticed and rectified prior to affecting System Operation*	Risk-averse approach to contracting reserves
New assessment of component loading (4.8.3)	Yrs	Reduced component load rating (cables, lines especially)	**Low** *May increase system congestion*	**Medium** *Likely that components will be operated in a degraded state for some time before replacing*	Expedite component maintenance (out of scope of System Operations)
System load forecasting error (4.3.3, 4.4.4, 4.5.3, 4.6.5, and 4.7.2)	Mths -Days	Affects generator dispatching, reserve commitments, and outage scheduling and hence system load	**Low** *Iterative forecasting results in gradual risk management, but errors would result in inefficient*	**High** *Forecasting of exogenous variables is highly error prone*	Continual refinement of demand forecast models

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			reserve use		
Market clearance/ Communication (4.4.6)	Days	Affects the day-ahead congestion forecasts and the final system state	**Medium** *Incorrect market clearance can result in over-use of reserve generation or costly redispatching*	**Low** *Congestion forecasting is generally risk averse (given N-1 criterion)*	Continual improvement of congestion forecast accuracy and risk averse reserve procurement
Emergency outage requests (4.5.4)	Wks - RT	Potential changes to outage schedule and hence system topology	**Medium** *Required emergency works may result in unavoidable system losses*	**High** *The occurrence of emergency requests is almost certain*	N-1 (or N-1-1) contingency analysis
Weather, RES production and congestion forecasts/alerts (4.3.4, 4.3.5, 4.4.7, 4.4.9, 4.5.5, 4.5.6, 4.6.7, 4.7.4 and 4.8.4)	Days - RT	Changes the risk of the system, supply from renewable sources and hence the system topology and loading	**High** *Lightning and other environmental effects are a highly common source of component failures and ENS* [ENTSO-E, 2014a]	**High** *Seasonal based, but very common compared to all other risks*	Frequently updated weather forecasts, and risk-averse (preventive) approach to operation during storms
Unexpected change of System State (all workflows)	RT	Component failures affect the ability of the system to achieve the planned level of service	**High** *Sudden faults (not due to weather) may also result in relatively sudden, severe consequences. May lead to cascading faults.*	**High** *Sudden failure of a single component is relatively common compared to other listed risks*	Ensure robust grid operation by using N-1 or alternative reliability management to handle unexpected outages
Unexpected multiple changes of System State (all workflows)	RT	Covering simultaneous component faults to cascading faults, or blackout situations	**High** *Most likely event to lead to a total system blackout, given that current grid management only covers single component faults*	**Low** *Less common than single component faults, but may result from a single fault that is not restored quickly*	Ensure fast and robust grid assessment of frequency, loads and voltages, as well as more robust risk assessments. Ensure grid restoration/ protection occurs in coordination with other TSOs.

The items in Table 4.1 show that risk is introduced and accepted in timescales that extend beyond that of system operation (weeks in advance of operation to real-time operation). The GARPUR project aims to describe the probabilistic risk of the system at a particular point in time, but it is important to note that risk enters the system at differing time scales, even within a system operations context. Similarly specific levels of risk are accepted at different lead-times. That is, the risk associated with adopting operational policies to some new regulation will affect long-term system reliability, whilst redispatching generation may only affect reliability for the next hour. These operational decisions may occur simultaneously, but they accept different risks at different time scales. The risks are classified by a qualitative risk assessment, relative to each other, regarding the context of system operation. This qualitative risk assessment suggests that the key risks to system operation are changes in weather, emergency outage requests, and unexpected faults (especially multiple concurrent faults). These risks are all presently managed by applying the N-1 criterion or more risk averse reliability assessment methods within the planning time frame.

In the context of the GARPUR project, it is impractical to model all the events listed in Table 4.1 (e.g. quantitatively predicting the likelihood and consequence of regulatory change). In a system operations

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context, the direct sources of risk are the forecasting events, the emergency outage requests, the market communication/clearance, and the unexpected changes in system state. The detail to which each of these sources of risk are modelled depends upon the mathematical and practical feasibility, which will be assessed in a later stage of the GARPUR project.

In addition to discussing the main sources of risk in system operation, it is also useful to discuss the actions available to the operator which can be used to directly affect the system state. These direct control actions are listed below in Table 4.2. The response to the questionnaire (sent to 10 TSOs) revealed that these direct actions are common to all. The effect each of these actions has on the system depends entirely upon the design and state of the system, as well as the specific line, node or component that is acted upon. As such, the impact of each action cannot be quantified in a general sense. Instead a reliability assessment framework must allow for each action item to act as an input to the model, and must then be able to calculate the consequences of each action for the specific system (state) being modelled.

Table 4.2: Direct actions available to affect system reliability in System Operations

Direct Actions	Possible reasons to perform action
Change circuit breaker positions	Remove line for outage work, affect bus voltages, redirect system loads, reduce losses
Release scheduled outages	Return line to system after outage work, or interrupt outage work to improve system reliability
Manually activate reserves	Compensate for significant loss of generation, or spatially redistribute automatically activated reserves
Change reactive compensation	Regulate system voltage, or reduce system losses
Change tap-changer positions	Regulate system voltage
Redispatch generation	Affect line loading, or regulate voltage/frequency
Curtail load	Reduce line loading, or regulate voltage/frequency
Set phase-shifting transformers	Regulate system voltage, or reduce system losses
Set system protection	Reduce consequences of significant faults

It should also be noted that each of these actions can occur as either preventive or corrective actions. That is, they can either occur in anticipation of some risk to the system, or as a reaction to some realised contingency. Ideally a new probabilistic reliability management framework will be able to compare the value of preventive and corrective approaches, and to find the optimal mix of the two approaches for a given system.

In addition to the direct actions, it is also possible to define a set of indirect actions which a TSO can apply in order to affect the reliability of the system. These actions are listed below in Table 4.3. In contrast to the real-time direct actions, the majority of the indirect actions occur hours to weeks (and potentially years) in advance. For readability the actions are listed from the longest time frame to shortest. Additionally the main reasons to perform each action are listed in the table.

Table 4.3: Indirect actions available to affect system reliability in System Operations

Indirect Actions	Time Frame (ahead of real-time)	Main reasons to perform action
Revise operational policies	All/Any	Inefficient procedures across some tasks
Revise component load limit definitions/calculations	All	Inefficient knowledge of use of component capacity, leading to sub-optimal risk management
Revise reliability targets	Years	Sub-optimal system-wide reliability performance
Revise system protection planning process	Years	Sub-optimal automated protection processes
Revise contracting procedure/goals for	Years	Sub-optimal over/under investment in reserves

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new reserves		
Revise price area definitions	Months to Years	Address long-term congestion issues
Revise outage scheduling procedure/timing	Hours to Months	Sub-optimal management of component failure risks
Revise congestion forecast procedure/timing	Hours to Days	Sub-optimal communication of risk between market areas
Revise system load forecast procedure/timing	Hours to Weeks	Inefficient commitment of reserves, setting of tap-changer positions or acceptance of risk with outages
Revise reserve classification and commitment process/timing	Hours to Weeks	Inefficient over/under allocation of reserves for given time periods
Revise weather forecasting procedure/timing	Hours to Days	Inefficient awareness of weather-related risk in system operation tasks
Revise intra-day forecast procedure/timing	Hours	Sub-optimal communication of system risks to operators or stakeholders
Revise system monitoring output	Real-time	Inefficient operator awareness of system risk or impacts of potential actions on system risk
Revise scheduled outage release procedure/timing	All	Inefficient communication of post-maintenance component health

The indirect actions are more difficult to model, in that they do not affect the system state but affect the operational procedure itself. The decision to use an N-1 reliability criterion instead of an N-2 or N-0 criterion is in itself an indirect action to affect the system reliability. Similarly the decision to use a probabilistic reliability criterion is equivalent to revising reliability targets, which may then result in a revision of the system monitoring output available to operators in the control room.

Therefore this table identifies the different opportunities available to the GARPUR project through which to affect system reliability. Each of the actions are presently optimised based on some internal TSO specific risk assessment (in most cases a cost-benefit analysis or N-1 assessment), or are simply set by regulation (such as a minimum reserve capacity). In a system operation context GARPUR could affect the entire process by replacing the N-1 criterion with a similar, general principle that defines reliable operation. Alternatively the GARPUR reliability framework may exist entirely separate to the workflows, and model the black-box interaction of using the actions listed in Table 4.2 to manage the risks listed in Table 4.1. Such a model would be equivalent to revising the system monitoring output, as it would likely be used by operators within the system control room.

The comparison between these opportunities, and the decision to pursue a particular opportunity, should be based upon an assessment of mathematical and computational feasibility, general applicability to TSOs, and a comparison of likely benefits compared to the existing process. This assessment should be an ongoing process throughout the GARPUR project, given that a comparison cannot be made until some conceptual models have been defined.

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5 DATA, SOFTWARE AND COORDINATION

The workflows described in Section 4 describe a large number of tasks that are based heavily on capturing and analysing data and the use of software tools. Measuring, estimating, and observing the system state is the most crucial task in real time operation of a transmission system. This section will discuss the data, software, and coordination between TSOs, based on responses from the questionnaire (Appendix A.1).

Technical specification of TSO control and information systems, software and databases, is only mentioned marginally or indirectly in the questionnaire. Nevertheless, it is clear that broad software architectures are optimised based on the TSO's needs.

In particular, the more a TSO is interconnected with its neighbours, the more likely are integrated data storage implementations and congestion planning tools. In order to present storage and software options currently available, an inclusive, rather than an exclusive approach is adopted in this section. In other words, all reported database architectures and software tools are described without including TSO specific idiosyncrasies to provide a composite image of what is possible. An alternative approach, not taken in this section, would be to describe storage and software tools that can be expected at the majority of TSOs (related to the average TSO described in Section 3 and 4 in this report). However, from a storage and software point of view, it is more informative to go for an inclusive approach when describing current practice amongst European TSOs.

As in Section 3, a summary of the questionnaire results is presented first. The summary is then formulated into representative workflow diagrams representing both the database structure and software execution.

5.1 Data and tools

Below is a compilation of the data and tools TSOs reported in their answers to the questionnaire. It is not likely that the figures are exhaustive. In addition, it may prove necessary to further specify a) database filling (timing and frequency), b) database administration, and c) software processing constraints relative to real time.

Figure 5.1 below shows the data types collected by all/most of the TSOs to support decision-making in real-time operation and operation planning.

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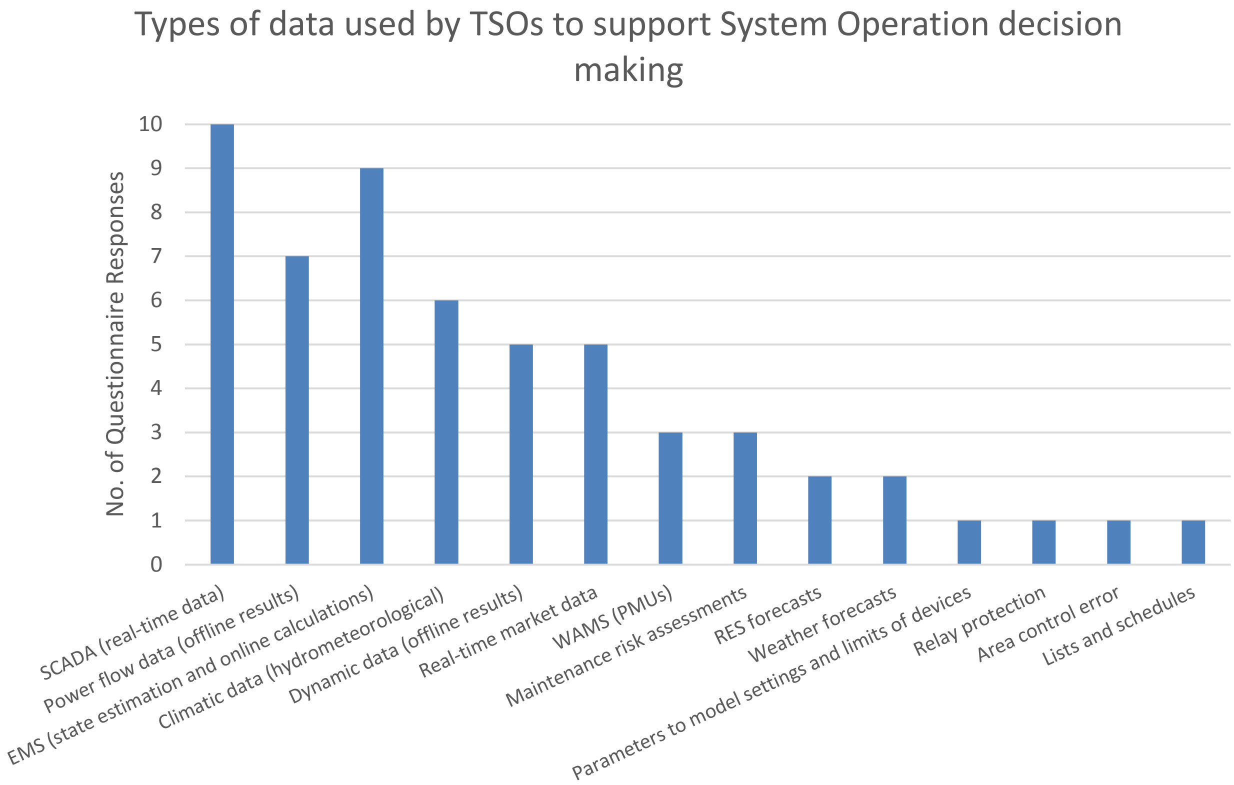

Figure 5.1: Compilation of data TSOs use to support decision making in system operation

The data described in Figure 5.1 can be partitioned into three categories based on TSO utilisation. Data used by most TSOs (7 or more, out of 10) includes SCADA/EMS and offline power flow data. All TSOs use SCADA and most have SCADA/EMS control systems. A few TSOs use EMS functions separately but most combine EMS functions with SCADA through steady state estimation. Power flow off-line data is also common as it includes grid topology, state estimation results, and steady state parameters based directly on control system exports.

Data used by approximately half of the TSOs (3 to 6 TSOs) includes climatic data, dynamic data, real-time market data, WAMS, and maintenance risk assessments. This data is either generated by advanced tools (e.g., intraday energy markets and PMUs) or obtained by higher-level analysis (e.g., calculation of dynamic rating). Climatic data is used for monitoring and estimation of RES production and weather dependent limits. Dynamic data is derived from steady state data and usually manually fitted to dynamic parameters. Real-time market data of prices and generation production are used in dispatch control rooms for system balancing and load frequency control in market-driven regions. WAMS based on PMU technology depends on the regional technological uptake. WAMS usage directly in the control room was reported by one TSO. WAMS is described in more detail in section 5.1.1. Maintenance risk assessment is usually used by asset management departments and completed in real-time operational planning mostly for dynamic rating calculations.

Data used by the minority of TSOs (2 or less) includes RES forecasts, weather forecasts, parameters to model settings and limits of devices, relay protection, area control error, and lists and schedules. In some cases the usage may have been erroneously reported. In the case of control system data, all of the TSOs use parameters of model settings and limits of devices as a part of the control system, but only one TSO mentioned them. Relay protections warning and alarms are also a part of SCADA data and operationally important relay protection settings are components of the grid model parameters in control systems. Other data is indeed used rarely by TSOs partially due to low RES penetration or low interconnectivity

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with neighbouring regions. In regions with significant RES installations, estimation of local RES production (e.g., local photovoltaic production at the level of TSO/DSO transformers) and weather dependent limits may be used in real-time calculations and grid model snapshots. Highly interconnected TSOs rely more heavily on congestion forecasts and regional balancing. The RES forecast data, forecasts of weather dependent limits, as well as data from lists and schedules, are all considered during the congestion model generation process. In a multi-area power system, the area control error is used for load frequency control.

Figure 5.2 below shows the analysis tools implemented by TSOs to support decision-making in real-time operation and operation planning.

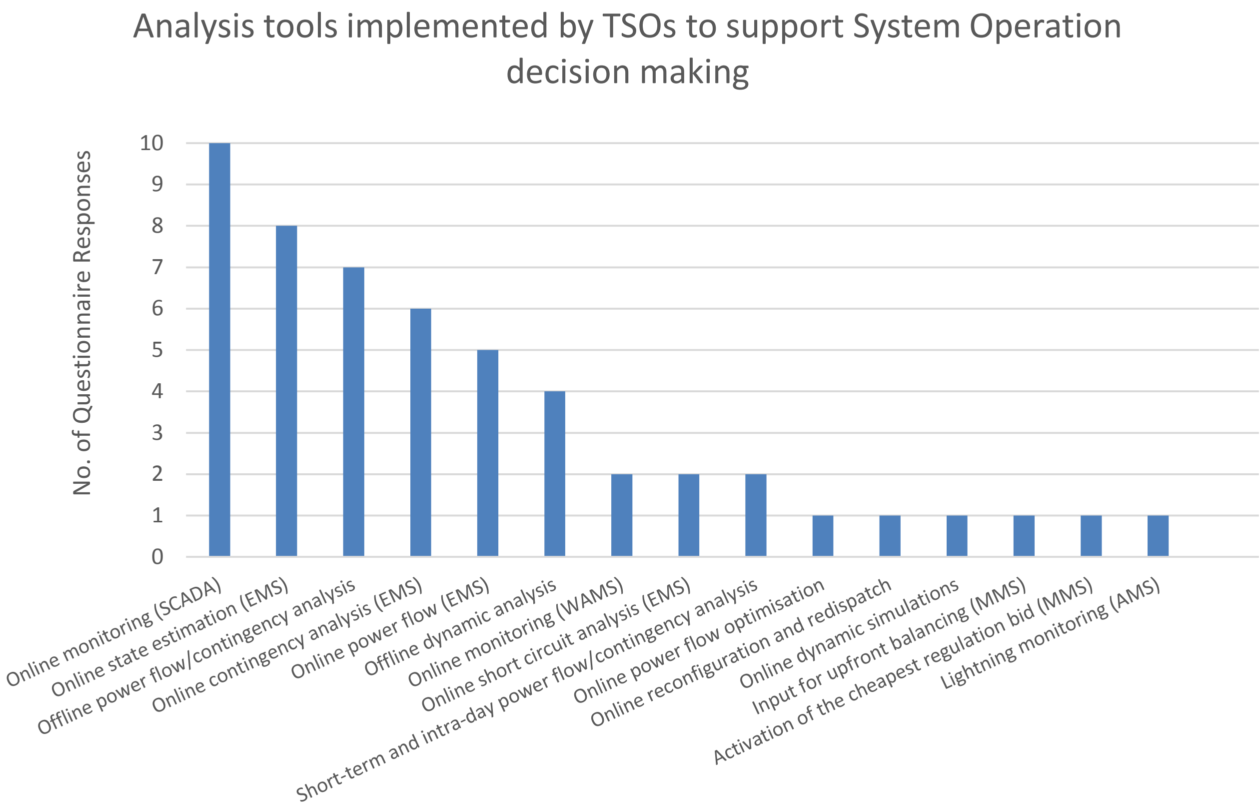

Figure 5.2: Analysis tools implemented by TSOs to support decision making in System Operation

The software tools are subject to the same usage patterns as their associated data described above. It should be noted that special SCADA software like remote control, software blockades based on EMS results, and real-time limit setting was not queried separately. Similarly, TSOs did not mention regulation software like load-frequency and voltage control separately from SCADA/EMS control system. A half of TSOs mentioned DACF but only 2 TSOs mentioned short-term power flow and contingency analysis. The information is straight against section 5.2, Figure 5.3 where more than half TSO is putting together DACF models. DACF are used in short-term and consist results of power flow and contingency analysis.

Only one TSO mentions online power flow optimisation (EMS) but many TSO use voltage control or present pilot nodes.

Models formulated within real-time and operational planning processes incorporate various information levels of neighbouring systems:

- TSO
- Observability Area (TSO + surrounding loops)

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- Region (CEE)
- Continental Europe (more than 12 TSOs)

Differences in incorporation of on-line data by analysis tools (On and off-line) were also observed:
- SCADA/EMS component,
- Model for off-line tools is exported directly from SCADA/EMS,
- Model for off-line tools is based on exported data but it is compiled out of SCADA/EMS.

5.1.1 PMUs

A Phasor Measurement Unit (PMU) is a device that provides real-time measurements of electrical voltage and current. Multiple units can be synchronised in order to allow for direct comparison of multiple points on the transmission network, allowing for accurate phase angle calculations, among other power flow calculations. It is anticipated that PMUs will allow for greater accuracy in the state estimator, as well as improve the viability of using dynamic line ratings. PMUs are presently in an adoption phase in Europe, as suggested by the results of the questionnaire:

- One out of ten TSOs has not installed PMUs,
- 6 TSOs have PMUS in use. PMUs are used for off-line analysis and R&D projects,
- 3 TSOs use PMUs in operational context.

A system of PMUs can be defined more generally as a Wide Area Management System (WAMS), which is a system of devices and information processing that allow for the transmission system to be observed and interpreted in real-time. The obvious benefits of using WAMS instead of traditional state-estimation are that it provides a real-time measurement of the system rather than a periodic estimate. According to the questionnaire, European TSOs are interested in developing and utilising WAMS for the following reasons:

- System analysis
  - Off-line analysis for past events
  - post-contingency analysis of events that occurred on the grid
- Dynamic model verification and improvement
- Monitoring oscillations
- Fault analysis
- Real-time visualisation of the system (grid monitoring)
- State estimation enhancement

5.2 Models

All state estimators are fully integrated with SCADA/EMS, and many tools make use of the state estimator. All of these tools implement fully integrated models that are usually breaker oriented.

Models can be characterized according to size and preparation method. Models are grouped according to size as follows: TSO's own model together with
- A few monitored border substations,
- On-line external observability area
  - First loop only,
  - Neighbouring TSOs,
  - More than neighbouring TSOs.

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- On-line equivalent based on external data (historical, forecasted or expected).

In addition, two TSOs use dynamic rating.

Figure 5.3 below shows the proportion of TSOs that undertake congestion forecasting. The number of "No" responses are also shown, given that not all TSOs provided a response regarding DACF. The congestion forecasts are produced automatically, except for one TSO who creates a D2CF manually. One respondent clarified that they only undertake IDCF for main transmission corridors.

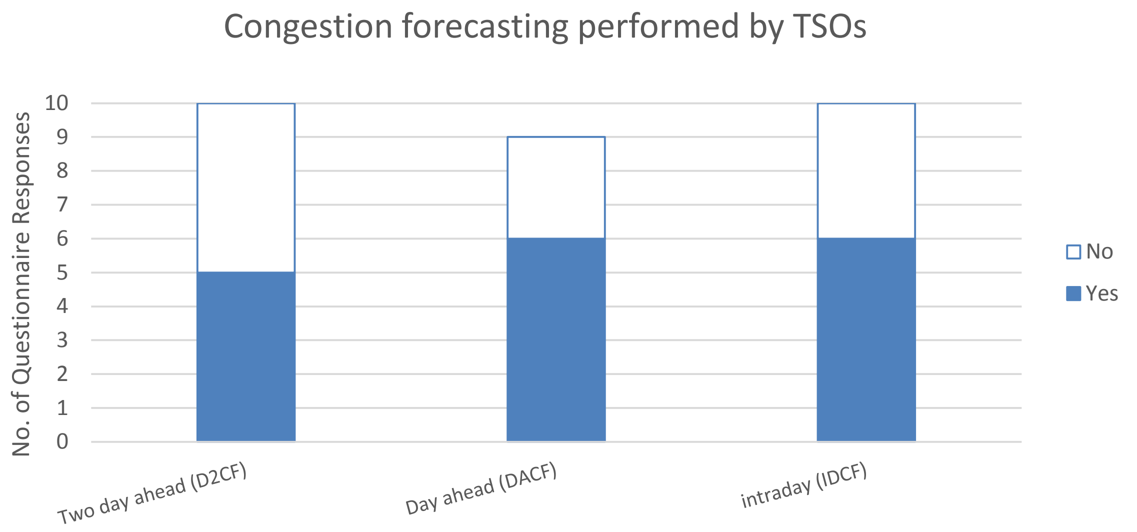

Figure 5.3: Congestion forecasting performed by TSOs

All TSO that created DACF automatically included upcoming plans and forecasts:

- System balance schedule
- Generation schedule
- RES forecasts
- Outage schedule

In addition, 1 TSO includes a dynamic rating schedule.

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5.3 Database structure

Dataflows describing common TSO collection and database filling strategies are summarized in the figure below. More detailed figures are contained in the sequel. The dataflows corresponding to data collection precede the real-time horizon and begin approximately 1 day in advance (e.g., generator plans and operational schedules) and continue all the way to real-time. The dataflows corresponding to model formation in the real-time horizon are usually completed immediately and must be complete within 15 minutes. The database architecture formalism adopted in this section assumes each department and physical entity includes its own datastore and updates data in other datastores at regular time intervals (1/D, 1/h, 1/15m, 1/m) or following event triggers (EV). In addition, an integrated data store where all data, parameters, schedules, etc are gathered, was included to simplify the communication scheme. Some TSOs implement direct communication schemes where data is passed directly to interested parties.

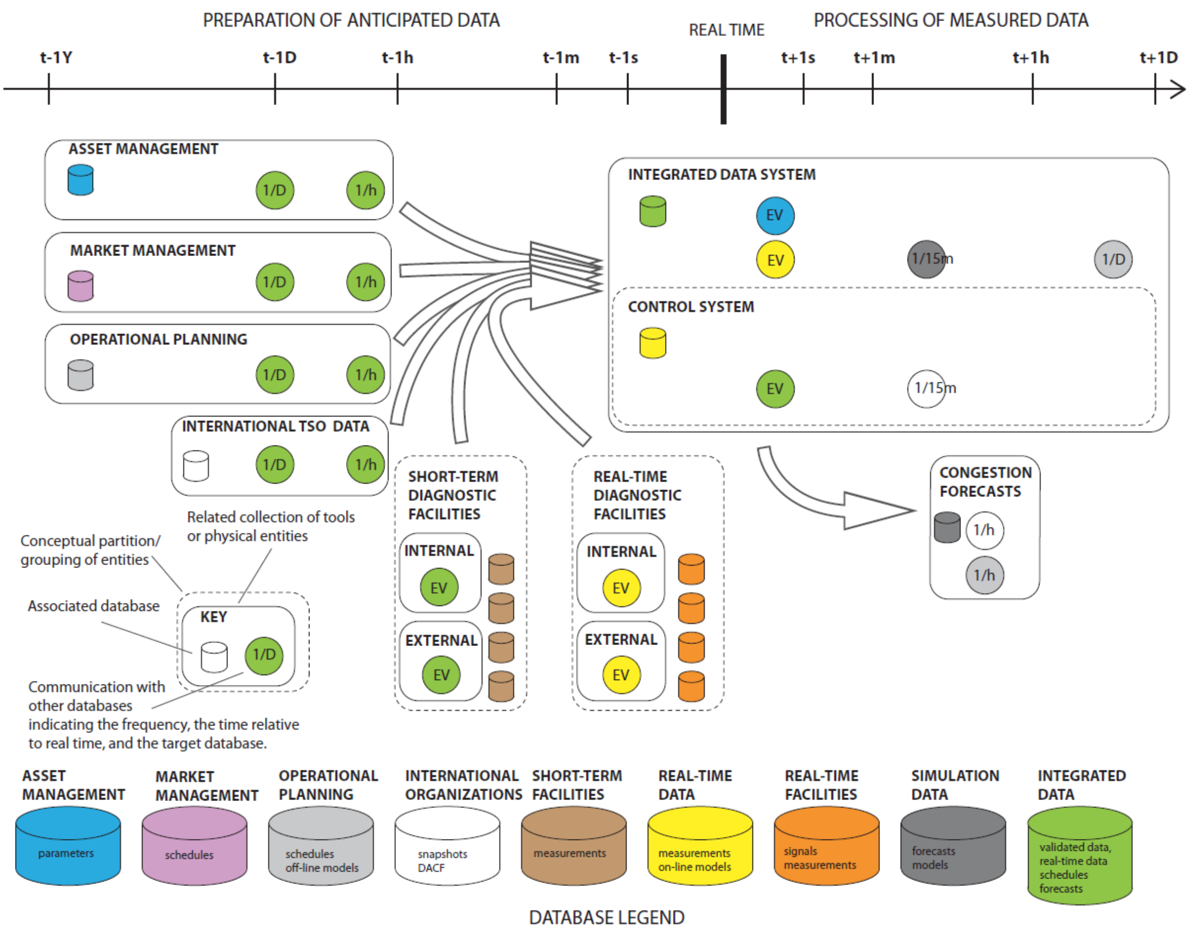

Figure 5.4: Data flow overview

Common trends can be summarized as follows: A unified way of data storage and retrieval does not exist. For instance, each database illustrated above can be replaced by a manual input.

The standard TSO database is a relation object database (for example SQL). The database objects describe relationships between equipment using object modelling. Each situation stored in the database can be instantiated according to object modelling rules created for computation purposes, merge, export, etc.

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Each TSO uses SCADA and EMS control systems and each TSO is able to collect snapshots, where a snapshot refers to a data file containing all necessary data for steady state calculations. The resulting snapshot is usually saved in a native SCADA supplier data format. Most SCADA systems are able to export to standard grid data formats. Six out of eleven TSOs reported using the standard UCTE format for steady state data in the questionnaire. The newly proposed CIM format was not mentioned in the questionnaire.

A database workflow diagram in a format similar to those in Section 4 is given in the Figure 5.5. The database names are contained in bold in the left column with corresponding data types. Each data type is either derived from an exogenous input or from a feedback input. The boxes to the right mark data entry updates. Updates in short-term and real-time databases are coloured in black. Updates in other databases are not provided in detail. Only those updates leading to ST/RT database updates are shown in yellow. The control system database is omitted from the left column because its entries are derived directly from other databases. Instead, entry updates of the control system database are explicitly shown in red. While this workflow diagram includes great detail, information relating feedback outputs to feedback inputs is missing. This information is included in Figure 5.6.

The data types include real-time data as well as grid model snapshots and forecast derivatives. Data interface between information systems (MMS, AMS) is mentioned. The grid model is collected in SCADA/EMS. Each SCADA/EMS is able to export the model snapshot, which is frequently used by all but one TSO.

It's important to keep in mind that about half of the TSOs do not use day ahead congestion forecasts and the other half use all grid congestion forecasts (D2CF, DACF, IDCF). Not all TSOs used the real-time database to generate DACF and IDCF. Some TSO use an off-line database to realise that. This is typically linked to the process in place within the TSO. It is either the operational planning team that realized it or the real-time operation team. All data models are compared and assessed with reality and they are based on historical snapshots or historical compared forecasts.

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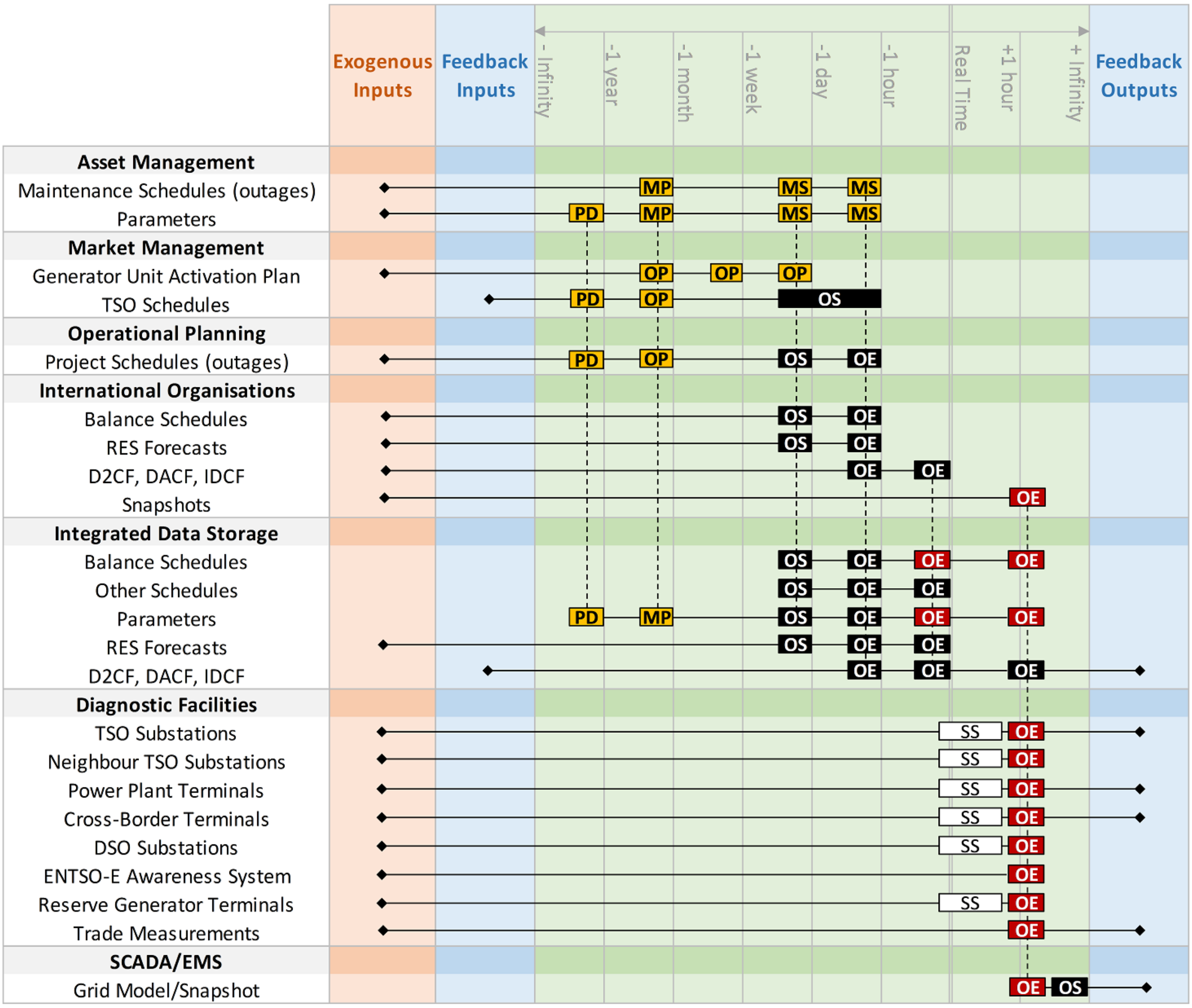

Figure 5.5: Database workflow (See Figure 4.1 for label definitions)

The general database structure comprises the following databases described in more detail below:

- Asset management system database (AMS DB)
- Market management system database (MMS DB)
- Operational planning database
- Multi TSO databases
- Integrated data store
- Diagnostic facilities databases
- Control system (SCADA/EMS)[6] database
- Snapshot and forecasts grid model storage

DMS (Document Management System) wasn't mentioned in the questionnaire.

[6] All TSOs use SCADA and EMS systems. The systems SCADA and EMS can be use separately but they usually work together in one control system of type SCADA/EMS. 4 out of 10 TSOs use control system of SCADA/EMS type. TRISQ and GE XA/21 control systems are SCADA/EMS types as well. As result at least 6 out of 10 TSOs have SCADA/EMS control system.

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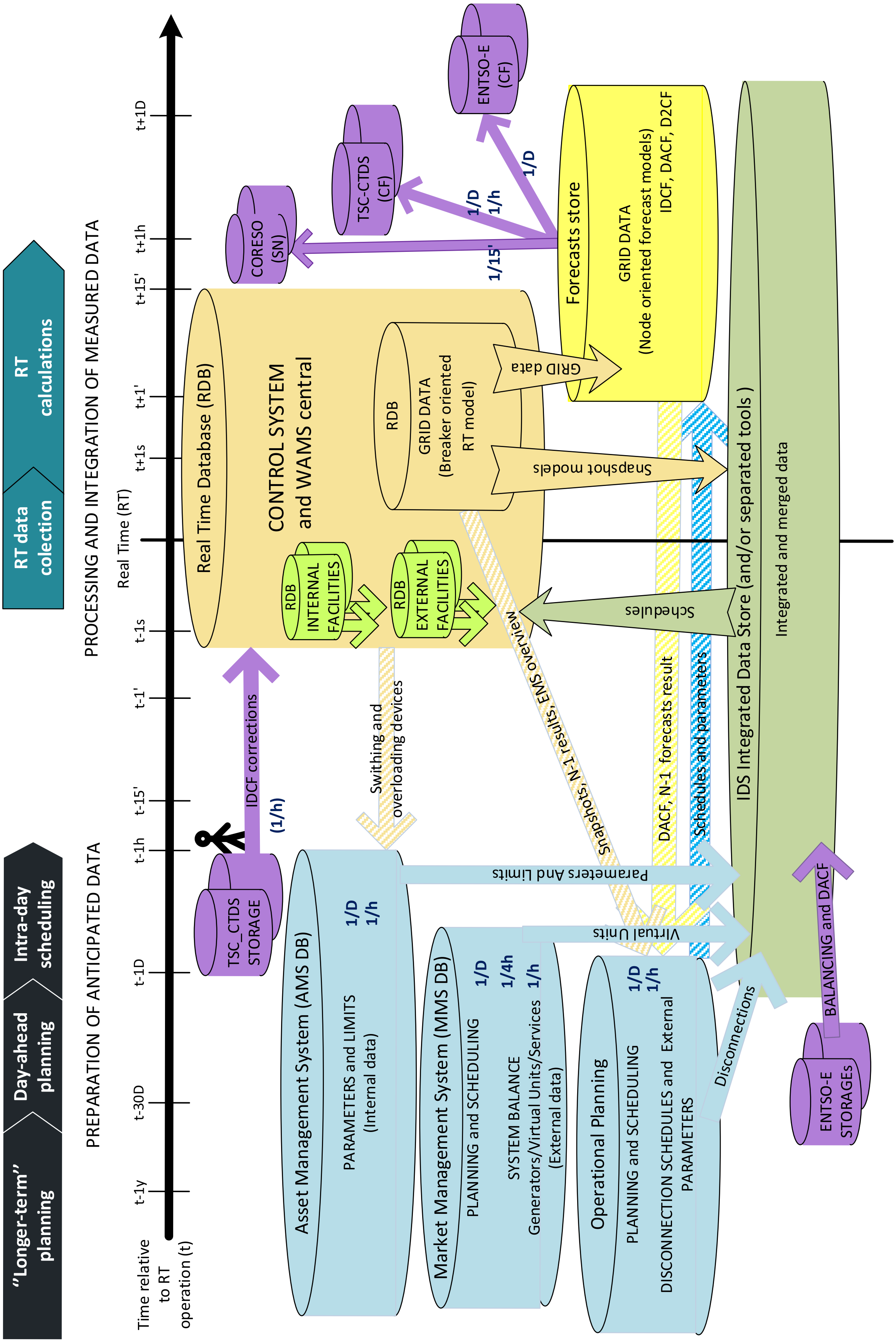

Figure 5.6: Database structure

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5.3.1 Asset management system database

Asset management system database (AMS DB) includes TSO devices describing their condition and device model parameters of lines, HVDC links, transformers, reactive power compensators, substation parts etc. as well as device limit parameters.

5.3.2 Market management system database

Market management system database (MMS DB) contains information regarding generator or virtual unit production and connection to the grid, prices, e.g., a plan and schedules for the next few days or hours.

5.3.3 Operation planning database

Operational disconnection and maintenance database includes information regarding branch (line, transformer, HVDC links, busbar connector etc.) disconnections, plans and schedules for the next day, two days or a week. The database includes historical power flow snapshots and forecasts grid model. What kind of grid model is link to the process in place within the TSO.

5.3.4 International organisation databases

International organizations such as CORESO[7] and TSC[8] provide coordination services to highly interconnected TSOs in continental Europe. They provide IT platforms for data exchange and N-1 security assessment.

Coordination within CORESO is based on real-*time* data of CORESO members and grid snapshots from other TSOs. Once the grid security calculations are complete, member TSOs can access the results.

Coordination within TSC is based on forecasts data from all TSOs of continental Europe. This data is transferred to a common IT platform where it is merged into a single database and serves as the basis for all subsequent grid security calculations. TSC uses the common software tool CTDS worked with common merged model of continental Europe. Everyday evening conferences are used for coordination of preventive actions inside of the TSC region. Once the grid merged models are complete, member TSOs can calculate/use the results.

5.3.5 Integrated data store

The integrated data store provides a single place where TSO departments can access all types of formatted and properly arranged data including RES forecasts. Many TSOs do not implement integrated data store and opt for direct data exchange (in the questionnaire only 2 TSOs mentioned an integrated data store). The integrated data store is most often accessed by the control system to retrieve schedule and parameter data and prepared and collect data for different types of reviews and assessing.

5.3.6 Diagnostic facilities databases

Diagnostic facilities provide system measurements from both internal and external sources: Description of signals between control systems and substations within the TSO area

[7] www.coreso.eu
[8] www.tscnet.eu

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- Digital signals (breakers, disconnectors, protection alarms and warnings and another technology necessary for the remote control)
- measurements (active and reactive flows, frequencies, voltages, currents, tap changer positions, finish counting analogs like cross border energies, thermal line limits and different values and settings etc.)
- commands to change signal state or measurement value and orientation

Description of data from substations within the external observability area (the exchange data are based on [ENTSO-E, 2004])

- all switches status (on/off)
- active (MW) and reactive (MVAr) power measurements from all substation bays
- voltage (V) measurements from all busbars if available
- tap changers positions if available

Summary information from European Awareness Alarming Systems and/or Real-time Awareness Alarming Systems based on [ENTSO-E, 2004].

5.3.7 SCADA/EMS

SCADA includes a real time database (RDB) and is used by all TSOs. *The control system SCADA database* entries are shown in Figure 5.6 and includes snapshots, balancing schedules, parameters (loading limits), the grid model, all system actual telemetry signals and measurements from the diagnostic facilities.

Real time EMS database (is usually the same as included in RDB and) contains the full description of the consistent system state computed from the breaker-oriented model and all EMS software results.

Real time WAMS database contains phasors from PMUs (currents, voltages, frequencies and frequency deviations) and results of phasor calculations. The phasor data use frequencies 50 samples/s or 10 samples/s.

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5.4 Software structure

In the previous section the database workflow diagram was presented. In this section the software tools that either pre-process the data for further downstream use or analyse the data for system operation purposes are described.

A software workflow diagram in a format similar to Section 5 is given in the Figure 5.7 below. The software tools are grouped by the database on which they operate (shown in bold in the left column). Only processing steps are shown, data sources are omitted for clarity (see previous section for detail). Same colour coding as in previous section is used. Missing information regarding further software interconnections is included in supplemental Figure 5.8.

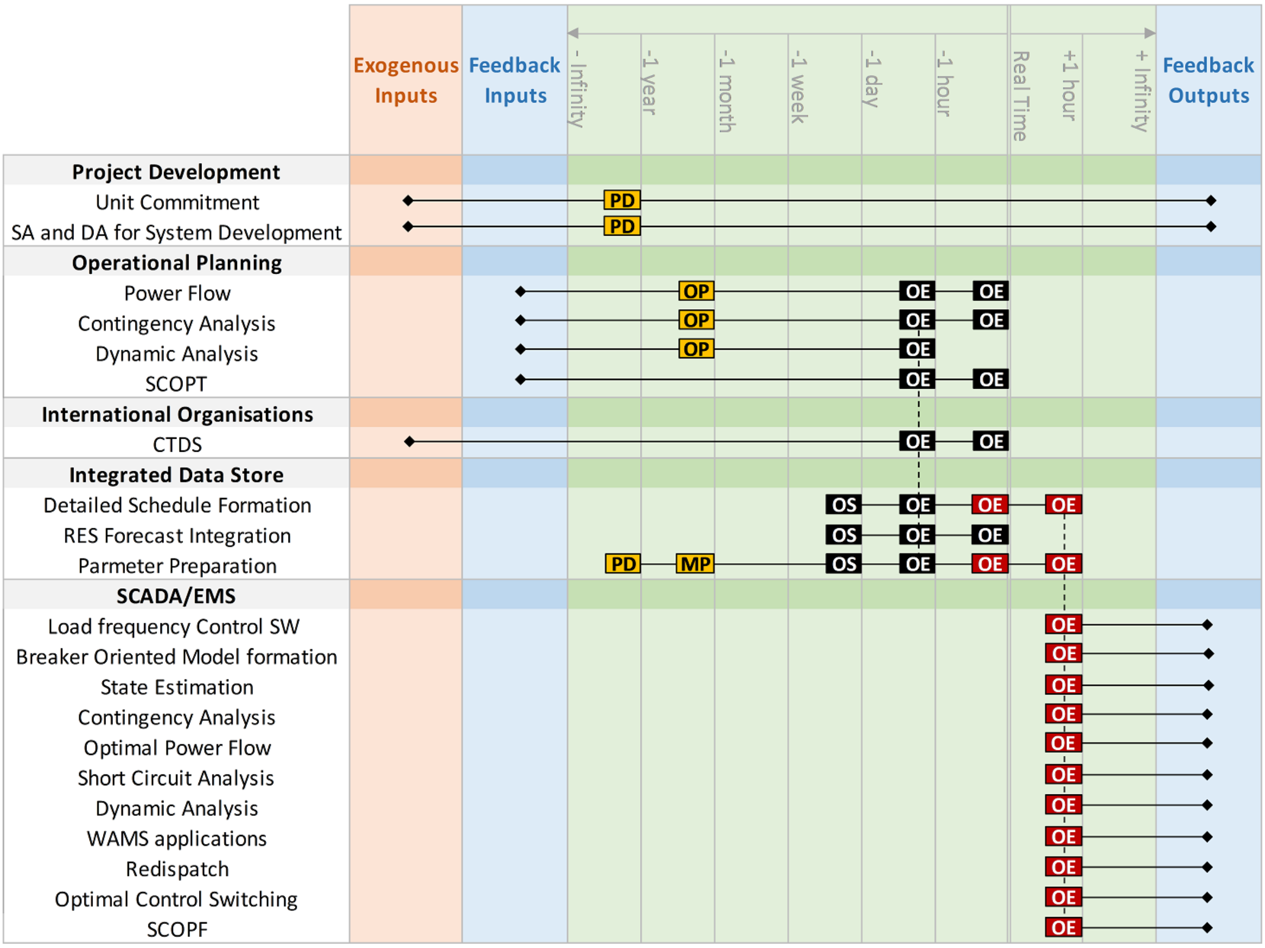

Figure 5.7: Software workflow (See Figure 4.1 for label definitions)

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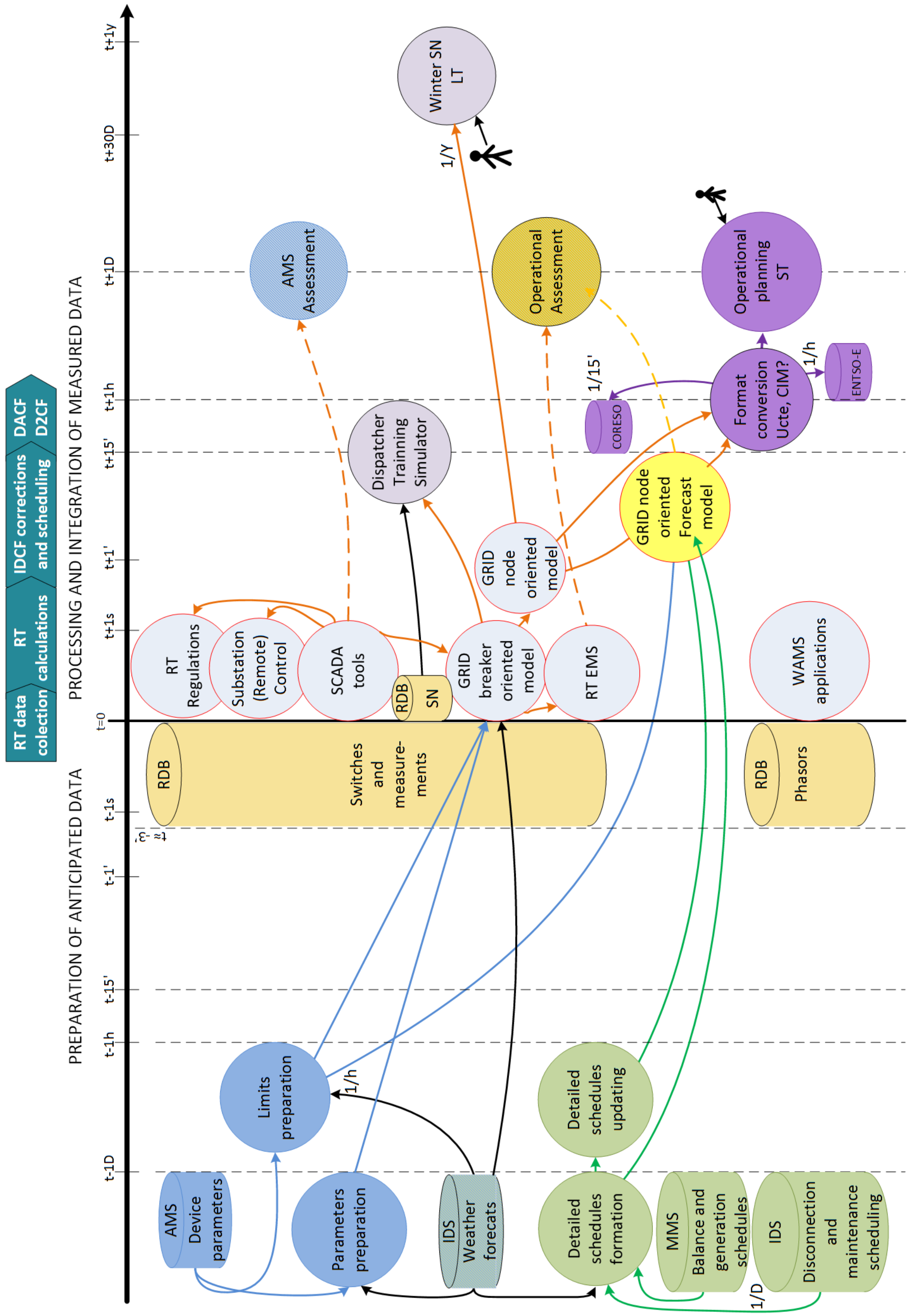

Figure 5.8: Software structure

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5.4.1 Operational planning

Operational planning and operational assessment usually use their software with basic functionalities. All TSOs mentioned power flow and contingency analysis, and some mentioned dynamic analysis. One TSO mentioned SCOPF. Two TSOs use control system for operation planning. All TSOs specify analysis tools but not the type of analysis tools. All specified analysis tools can calculate power flow and contingency analysis and they are agreed on ENTSO-E OH Policy 3 requirements [ENTSO-E, 2004].

5.4.2 Multi-TSO organisations

Multi-TSO organizations such as CORESO and TSC provide coordination services to highly interconnected TSOs in continental Europe. They provide IT platforms for data exchange and N-1 security assessment (see section 5.3.4).

5.4.3 Integrated data store

Integrated data store is the place which can substitute all data flows between main databases. Software contained here control data flows between databases, coordinates, and synchronizes them. The place is suitable for data collection software as well.

5.4.4 SCADA/EMS

Grid models are the basis for all other computations. Grid models are formed either within the SCADA and EMS or outside of the dispatch control system. Grid model formation outside of the control system or outside of the EMS requires additional data transits or manual inputs.

Grid model size and external observability areas do not present software issues and are not mentioned by one half of the consulted TSOs. Such TSOs use only a few neighbouring substations in their grid model. TSOs, for which grid model size and external observability areas do present software issues, are coordinated with other TSOs by cooperation organisations like CORESO and TSC. Such TSOs also form two day ahead (D2CF), a day ahead (DACF), and particularly intraday (IDCF) congestion forecasts.

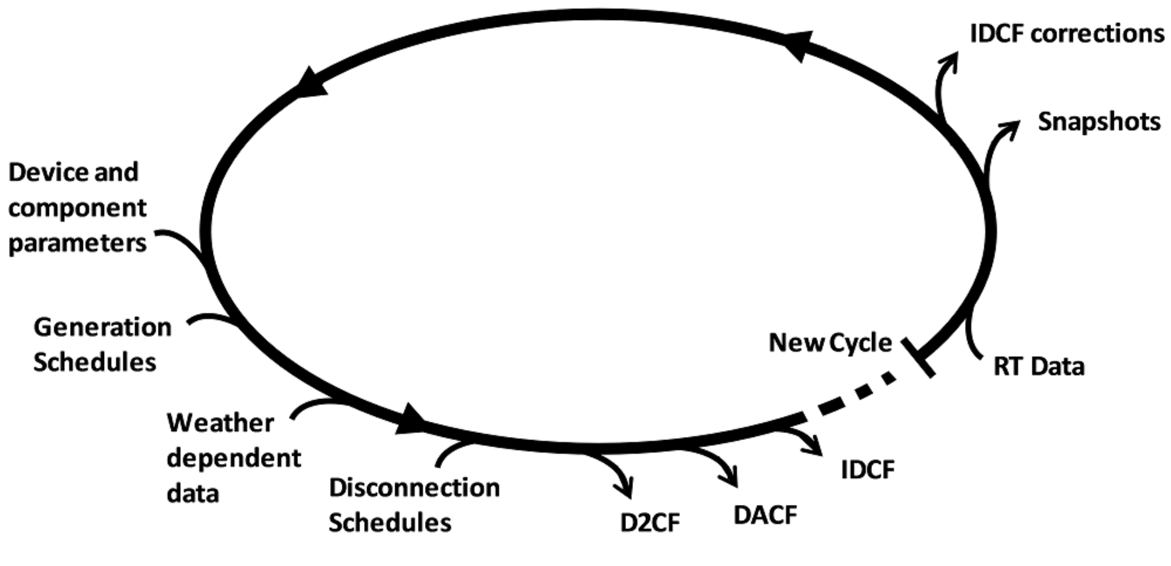

Figure 5.9: Grid models and data cycle

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Real-time EMS software as well as snapshot export software is commonly used. In general, real time software accesses the control system RDB inside of SCADA and/or EMS and can be grouped by function as follows:

- RT regulations (can be consider inside EMS)
  - Load frequency control (LFC)
  - Automatic generation control (AGC)
  - Automatic voltage control (AVC)
- Substation remote control
  - Automatic checking of switching (can be consider inside EMS)
- SCADA tools
  - Islanding
  - Snapshots creation
  - Grid breaker oriented model formation
  - Grid node oriented model formation
- Real time EMS
  - State estimation
  - Power Flow calculations
  - Short circuit calculations
  - Contingency analysis
  - Optimal power flows
  - Dynamic analysis
  - Redispatch
  - Optimal control switching

Advanced tools such as SCOPF (although not mentioned in the questionnaire) can be implemented using EMS based on Simulation Database, a temporary off-line database that contains additional functionalities as compared to the real time EMS. The Simulation Database with its software can easily run on the separate servers.

Other functionalities worth noting are listed below.

- WAMS applications need special RDB that can process fast phasor data with interface based on special requirements and IEEE C37.118 protocol [IEEE, 2011].
- Grid node oriented forecast model is based on time appropriate grid node model and modifications based on predictions, schedules and plans.
- Format conversion software is required only in case of different formats between TSO practice and ENTSO-E UCTE (CIM) format

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6 DISCUSSION AND CONCLUSION

This section interprets the content of Sections 3, 4, and 5, and gives some general discussion points and conclusions with respect to how to migrate towards probabilistic reliability management within the system operation process.

6.1 Potential for improvement of risk assessment

Most risk management tasks within the system operation context involve some expert judgement or human intuition. Even though outage scheduling and contingency management are largely based upon the N-1 criterion at present, the N-1 criterion is sometimes abandoned based on operator experience [GARPUR, 2014c]. An example of this would be a line allowed to operate in an N-0 state for a period of time due to the perceived consequences being minimal due to favourable weather forecasts. The use of expert judgement in the operational procedures of TSOs suggests that present risk assessment methods are not perfectly suitable. That is, operators perceive that they need to perform internal risk assessments in order to make exceptions to the N-1 criterion to properly capture the actual risk.

As discussed in Sub-Section 4.10, there are various opportunities to improve risk assessment in a system operation context. These range from replacing the N-1 criterion with something that captures system risk more completely, to treating real-time system operation as a black box with a mathematical model to suggest new grid actions based on changes to forecasts. Table 4.1 identifies the avenues through which risks enter the system operation workflow, and therefore defines potential points of improvement for forecasting and calculating risk. Table 4.3 lists the actions that are taken in system operation that affect system risk, and therefore each of these actions identify an avenue for improvement of procedures themselves. That is, opportunities exist to revise the systematic approach to risk by suggesting new reliability criteria, as well as changing how and when forecasting and scheduling tasks occur. Finally Table 4.2 lists the general direct actions that system operators may take to affect the system state, which may also be analysed in a risk assessment. The effect an action, or chain of actions, has on reliability may be forecasted and presented to the operator, assuming that the system reliability is assessed in real-time.

Potential improvements of risk assessment in the system operation context, in order of increasing complexity, are:

i) Calculate system reliability in real-time and display in the control room (either as a system-wide parameter, or as a risk map over the system)
ii) Create a model to estimate the effect of actions, or chains of actions, made in real-time on system reliability
iii) Create forecast models of exogenous inputs, including measures of forecast reliability (i.e. standard deviation for normally distributed variables)
iv) Use forecasts to make projections of system reliability to inform actions taken outside of the real-time context
v) Create a model to estimate the effect of actions, or chains of actions, made hours-weeks ahead of real-time on future system reliability
vi) Implement an optimisation algorithm that searches the set of possible direct and indirect actions to minimise risk-weighted costs.

There are however a number of barriers that exist to implementing such improvements. One such barrier is the lack of information on how exogenous factors affect line failure probabilities. System operators have general knowledge about the long-term reliability of specific components, but there is presently no method in use for calculating a dynamic short-term reliability of components based upon weather variables (i.e. increase in risk due to an increase in wind speed).

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Resolving the gap between the present intuitive approach to manage this risk and the ideal quantitative approach GARPUR intends to implement is also a significant barrier to short-term risk assessments. The use of expert judgement suggests that present risk assessment methods are incomplete. Another important aspect to consider within the GARPUR project is the currently available data, databases, and software solutions used amongst European TSOs, discussed in section 5.

6.2 TSO Coordination

In the short-term and real-time horizon, TSOs interact with different (neighbouring) parties, such as

- Other TSOs
- DSOs
- Generator companies
- (Other) Market players
- Regulators (in this time horizon mostly indirectly through regulations)

In a reliability management framework, it is important to take these interactions with other parties into account, as the actions of other parties affect the TSOs (and vice versa). Thus, in the GARPUR project, some attention should be directed at improving the coordination and communication (data exchange, communication format, etc.) with (neighbouring) parties. The objective can be, e.g., to improve the reliability of the grid and/or increase the efficiency of the coordination (e.g., look into shared reserves to reduce costs while maintaining a sufficient reliability level).

With whom, and to what extent, a TSO needs to coordinate with depends of course on the (geographical) location (of the TSO), the market regulations, DSOs in the area, etc. Below is the current practice of TSO-TSO coordination in Europe described – for the Nordic system and for the Continental European system.

6.2.1 TSO coordination in the Nordic power system

The synchronous Nordic power system covers Eastern-Denmark, Finland, Norway and Sweden (in Western Denmark the power system is synchronized with central Europe). The day-ahead market, Elspot[9], is the main arena for trading power in the Nordic countries. The TSO-TSO coordination (in the GARPUR WP6 context) can be split into tree topics:

- Outage scheduling: 3 times a year there is a common meeting between the Nordic TSOs where outage schedules are discussed
- Cross-border capacities: For the day-ahead market, each TSO sets transfer capacities based on, e.g., expected topology, internal bottlenecks, outages, stability assessments, etc. The transfer capacity available in the power market is the lowest among two capacities, if e.g., the Norwegian (Statnett) and Swedish (Svenska kraftnät) TSO sets different values for a given corridor.
- In real-time, the Nordic system is operated as one common balancing area, meaning that the cheapest reserves in the Nordic system are used for balancing purposes (as long as there are no bottlenecks). The balancing responsible party is either the Norwegian TSO (Statnett) or the Swedish TSO (Svenska kraftnät), i.e., the responsibility rotates between them.

Coordination with other stakeholders, e.g., DSOs and generators companies, is mostly in the form of bilateral meetings/discussions where outage schedules are discussed. In some cases it is possible for the TSO to use a DSOs network to transfer some power, but there are no formalized agreements here.

[9] http://www.nordpoolspot.com/

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6.2.2 TSO coordination in the Continental Europe power system

The synchronous Continental Europe power system covers the formerly known UCTE region (i.e., 29 transmission system operators of 24 countries operated synchronously). This power system is highly meshed and several day-ahead markets co-exist, i.e., CWE (Central Western Europe), Iberian Peninsula, CEE (Central Eastern Europe), Italy and SEE (South East Europe). The strong interconnections within the Continental European grid require common understandings for grid operation, control, and security. The expected TSO-TSO coordination (in the short-term horizon) is described in detail in eight operation handbook policies [ENTSO-E, 2014b]:

- Load-Frequency Control and Performance: This policy details the type of control actions, reserves, its hierarchical structure (Primary control, secondary control, tertiary control, time control) and the sizing of the reserves needed to ensure balancing of load and generation in real-time and to maintain frequency quality and stability. Finally, it also deals with the measures for emergency conditions.
- Scheduling and Accounting: This policy details the processes needed to schedule in advance the power to be exchanged at the interconnection borders between the system operators. It also deals with online observation of these exchanges and accounting processes.
- Operational Security: This policy details the principle of N-1 security, what should be considered within the contingency list, and how to manage events (corrective and preventive actions). It also deals with the coordination of voltage and/or reactive power management schemes, network faults clearing and short-circuit currents, stability and information exchange between TSOs for security of system operation.
- Co-ordinated Operational Planning: This policy details the processes needed to schedule unavailability of the grid elements for asset management. This policy also includes the determination of the NTCs (Net Transfer Capacity) between TSO areas. Description of Day Ahead Congestion Forecast (DACF) are also covered in this policy.
- Emergency Operations: This policy details with system operation in insecure conditions (defence plans such as under frequency load shedding volumes and triggering criteria) and with system restoration after collapse.
- Communication Infrastructure: This policy details the Electronic Highway (EH) network and its architecture, real time data exchange, file transfer exchange using ftp server, e-mail on the EH, information publication on EH using http server and non-EH communication.
- Data Exchanges: This policy is stating the Code of conduct to be followed by individual TSOs and generic rules of application when handling the exchanged data.
- Operational Training: This policy details the needs for inter-TSO training. It also defines the required training organization and dispatcher's accreditation. Finally, basic requirements for Dispatcher Training Simulator (DTS) are described.

Each of the policies holds standards which are requirements that must be met by each individual TSO and guidelines which are recommendations for process improvements. Auditing is performed on regular basis and policy evolutions are trying to anticipate system security needs.

Furthermore the Working Group Coordination Strategy within ENTSO-E has the mission for TSO cooperation and to develop collaboration to maintain and improve security of supply though the evolution of regional coordination with TSO agreements and Regional Security Coordination Initiatives. Part of this includes responsibility for the European Awareness System (EAS), a TSO power system state information system. The EAS provides real-time information about the following main indicators of each control area: frequency, load on tie-lines, network separation, alarming on states, Load-Frequency Control (LFC) mode, early warning before foreseen critical conditions, possible root causes, and possible locations of network splits (in the sense of "awareness"). All data is transferred via the Electronic

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Highway, a common technical infrastructure for all TSOs, which ensures high availability and reliability of the EAS.

International organizations such as CORESO and TSC also provide coordination services to highly interconnected TSOs in continental Europe, as discussed in section 4.3.5. Such international coordination organizations provide IT platforms for data exchange and N-1 security assessment, see section 5.3.4 for details.

6.3 TSO peculiarities

Some processes/challenges are quite TSO specific, and do not fit into the average TSO workflow diagrams (in section 3 and 4) in this report, but that does not mean that those issues are not important.

One such issue is the need for dynamic simulations as an extension or replacement of steady-state analysis. An example is transfer corridors in a system. In some cases, the maximum transfer capacity is limited by the thermal capacity of the lines constituting the transfer corridor. In other situations, the transfer capacity might be limited by stability issues, which in practice means that the maximum thermal capacity of the transfer corridor cannot be fully utilised. Such stability issues are best described and understood by performing dynamic analysis. In practice, it can be very difficult to detect such "dynamic transfer capacities", and for the purpose of the workflow diagrams in this report it has been difficult to identify a "clear cut" criteria for when TSO choose to use dynamic analyses in addition to steady-state analyses.

There are a lot of other issues that can be quite different from TSO to TSO, and might require some special consideration in terms of how a reliability management framework is implemented at a specific TSO. Examples of such issues are:

- Generation mix
- Connectivity (with neighbouring parties)
- Markets and market regulations
- Generation control
- Load (e.g., load flexibility)
- Regulations
- Natural hazard considerations (different environmental surroundings)

6.4 Environmental considerations

In the system operations context, one direct environmental consideration mentioned in the questionnaire responses was emissions, i.e., some TSO minimise losses to reduce unnecessary burning of fuel. The timing of maintenance activities may also have environmental impacts (i.e., such as clearing vegetation near lines during bird nesting season), but this is discussed in GARPUR D5.1 [GARPUR, 2015a].

Another environmental aspect to consider is reserve management, e.g., the type of generation sources used as back up. From a power market perspective, a TSO could, e.g., give transmission capacity priority to "environmental friendly" generation. In addition, regulations and operational policies might have an environmental impact in terms of enforced operational action/decisions. However, this seems to be outside the current practice of European TSOs in the short-term horizon (at least based on the questionnaire responses).

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6.5 Conclusions

The risks present in system operations are conditioned by decisions made in the system development and asset management workflows, covered in GARPUR deliverables D4.1 [GARPUR, 2015b] and D5.1 [GARPUR, 2015a]. The tasks that take place and the decisions that are made in the short-term operation of transmission systems are informed by frequent forecasts of system loads, weather, RES generation, and inter-TSO congestions. Most short-term actions are preventive in nature, aiming to ensure that system operation is reliable and has the appropriate level of redundancy (N-1 in most cases), and to maximise the options to perform corrective actions should a contingency realize. It is within the system operation context that unexpected changes to the system are managed, normally by following pre-defined procedures that have been developed by a mix of expert judgement and iterative improvement through experience.

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A.1 APPENDIX 1 THE QUESTIONNAIRE

A.1.1 General questions

Q1. Which of the following activities does your organisation address :	1 ☐ Generation planning 2 ☐ Transmission investment planning 3 ☐ Construction, ownership and maintenance of transmission 4 ☐ Transmission outage planning 5 ☐ Transmission operation 6 ☐ Other (please specify)
Q2. To what degree is your transmission network interconnected with other TSOs? (Total max NTC vs peak load)	
Q3. What is the rate of penetration of renewable generation (especially wind and solar) in your system… a) as a ratio between total renewable generation and total demand? b) as a ratio between peak renewable generation and peak demand?	

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A.1.2 Operation planning and real-time operation

This part of the questionnaire focuses on (short-term) operation planning and real-time operation, which roughly means a time horizon with a range from real-time up to about two months. In the following questions, please specify when the different analyses/activities takes place, either relative to real-time (e.g., t – 1h) or at a fixed time (e.g., Monday at 9am).

A.1.2.1 Tasks in real-time operation and operation planning

Q4. List the main tasks (in operation and operation planning) and describe briefly how they are organised, e.g., if they are allocated to separate teams or performed in separate control rooms. Examples of such tasks: • Day-ahead forecasting • Load forecasting • Congestion management Etc.
Q5. In real-time operation, what variables in your system do you monitor (and control)? What tools/data/models do you use for (real-time) control of these variables? Examples of such variables: • Frequency • Voltage • Congestion management (and/or power flows) • Component loading (load on lines, transformers, etc.) • Others? (Please specify)
Q6. When is the final/last approval of outages for maintenance purposes? Who in the organisation is responsible for this?

A.1.2.2 Secure power system operation (operation and operation planning)

Q7. How do you ensure secure operation of your power system? What are the greatest risks to secure operation of the system? What operational tasks are associated with these risks?
Q8. What is lacking today? (E.g., are there any important factors that are not sufficiently taken care of in the analysis performed today?)

A.1.2.3 Frequency and balancing control (Activation of reserves)

Q9. How do you choose which reserves to activate?
Q10. Do you have information about the exact location and amount of available reserves at each time? Please describe the information you have about available reserves in real-time operation.

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A.1.2.4 Voltage and reactive power control (Reactive reserves)

Q11. List the means of control your TSO make use of (manually or automatic) • Capacitor banks and reactors • SVCs or other FACTS • Tap changing or phase shifting transformers
Q12. How is the procurement and activation of reactive reserves from power plants organised?

A.1.2.5 Congestion management

Q13. How do you deal with congestion in (close to) real-time operation? (Here, congestion relates to bottlenecks not solved by predefined transfer limits, i.e., congestion as a result of system operation deviating from schedule)
Q14. When you experience congestion in real-time operation, do you use this information to update your operation planning models? If so, how do you do this?

A.1.2.6 System protection

Q15. How do you model system protection schemes? Please specify if, how, and when these models are set up, and how they are related to the operating criteria.
Q16. Do you consider system protection reliability? If yes, how is that taken into consideration?

A.1.2.7 Forecasting – Load, RES, and cross-border exchange

Q17. Production schedules (especially related to RES): How and when are these determined/updated? Moreover, what models do you use for this purpose (e.g., probability distributions, stochastic processes, etc.)?
Q18. Load forecasts: How and when are these determined/updated? How is uncertainty in load forecasts managed?
Q19. Forecast of cross-border exchanges: What models/tools do you use for this purpose? When/how often do you update the forecasts?

A.1.2.8 Determination of transfer capacities (operation planning)

Q20. Which software/tools/models do you use to determine transfer capacities?
Q21. When are the capacities given to the power market?

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A.1.2.9 Procurement of reserves

Q22. What models/tools/data are used to procure reserves? When is this done (i.e., how long before real-time operation)?
Q23. Is the amount of procured reserves determined by a criterion? (E.g., N-1 for conventional generator failures?) If relevant, how is the amount of (additional) reserves procured for backing up RES determined?
Q24. How are the must-run generators chosen? (Risk-based, minimum requirement for inertia, etc.?)

A.1.2.10 Preventive and corrective actions

Q25. The preparedness level chosen at each time: Do you have varying preparedness levels depending on weather conditions, load levels, etc.? What does it imply (e.g., more people on duty/stand-by)? What is the definition of the different levels?
Q26. Setting of corrective actions and choice of preventive actions: How/when are they changed/set/updated?
Q27. Energy and/or capacity limitations: How are these monitored, calculated, and/or evaluated?

A.1.2.11 Data and tools

Q28. What type of data (and data acquisition systems) do you use for decision making in real-time operation and operation planning? (Examples: SCADA, WAMS, climatic data, load flow data, dynamic data, risk assessment of maintenance work, real-time market data, etc.) • What is the data used for: Input to commercial tools, decisions based on the data itself, etc.?
Q29. What type of analysis tools and models do you use for decision making in real-time operation and operation planning? (Examples of tools and models: PSS/E, e-terra, DigSilent PowerFactory, load-flow, state estimation, models for non-observable areas, etc.) • For which decisions are the different tools used? • Are there any specific drawbacks with these tools/models?
Q30. Do you use online gathered data as input to online/offline analysis tools, e.g., is your SCADA system directly interfaced with some analysis tools? If so, please specify.

A.1.2.12 PMUs

Q31. How many are installed in your system? (Please specify this relative to system size, i.e., number of substations monitored with PMU's vs. total number of substations.)
Q32. What is the TSO's main goal with the PMU data?

A.1.2.13 Models

Q33. Do you use a state estimator on a regular basis? • How is the state estimator integrated with SCADA? (Fully integrated as part of the SCADA/EMS, or more as a separate tool?) • How do you create your model for real-time analysis? • How many external substations/nodes do you use in your observability area model? • What types of data do you use? • Which analysis tools make use of the state estimator (if any)? • Do you use a dynamic rating?
Q34. How do you create your DACF (Day Ahead Congestion Forecast) and D2CF (Two Days Ahead Congestion Forecast) models? • What tools do you use? Can you generate the DACF and D2CF fully or partially automatically? How can you check your model? • Do you automatically include the following plans and forecasts? o System balance schedule o Generation schedule o RES forecasts o Dynamic rating schedule o Disconnection schedule • Do you use contingency analysis in your DACF process?
Q35. Do you use intraday forecasts (IDCF)? Do you create IDCF models? If so, please indicate how.

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