SUPPORTING PAPER FOR OPERATIONAL PLANNING AND SCHEDULING NETWORK CODE

20.07.2012

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1 PURPOSE AND OBJECTIVES OF THIS DOCUMENT

1.1 PURPOSE OF THE DOCUMENT

This document has been developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) to accompany the consultation of the Operational Planning and Scheduling Network Code (OPS NC) and should be read in conjunction with that document.

The document has been developed in recognition of the fact that the OPS NC, which will become a legally binding document after comitology, inevitably cannot provide the level of explanation, which some parties may desire. Therefore, this document aims to provide interested parties with the background information and justifications for the requirements specified in the OPS NC, as well as the document outlines the following steps of the work.

1.2 STRUCTURE OF THE DOCUMENT

The supporting paper is structured within the framework for all SO NCs supporting papers as follows:

Background:

- Section 2 introduces the legal framework within which the SO NCs have been developed. Chapter 2.3 explains the next step for the OPS NC consultation.
- Section 3 explains the approach, which ENTSO-E has taken to develop the network code and outlines some of the challenges involved.

Explanatory notes:

- Section 4 complies with the requirements of the Framework Guidelines on System Operation (SO FG) regarding OPS NC developed by the Agency for the Cooperation of Energy Regulators (ACER).
- Section 5 focuses on the objectives of the OPS NC by topic, identifying the enhancement of technical requirements with an assessment of their associated benefits. Choices appearing in the code will be justified in this section.

1.3 LEGAL STATUS OF THE DOCUMENT

This document accompanies the network code on OPS, but is provided for information only and therefore it has no binding legal status.

1.4 RESPONDING TO THE CONSULTATION

In accordance with Article 10 (1) of Regulation (EC) 714/2009, ENTSO-E holds public consultations at an early stage in an open and transparent manner on all draft network codes.

All consultations are announced on the website of ENTSO-E: www.entsoe.eu and via the ENTSO-E News Alert. Interested stakeholders are recommended to register for notification of the commencement of formal consultations.

ENTSO-E will respond to the public consultations by:

- Allowing for confidential and non-confidential responses as appropriate to the subject matter, but in all cases setting out clear advice on how responses will be treated in advance.
- Making public all documents and minutes of meetings related to the consultations, in accordance with Article 10(2) of the Regulation.

- Making public all (non-confidential) responses received to formal consultations and the total number of responses received.
- Making public the final ENTSO-E position following the consultation, including an evaluation of the responses received explaining why comments have or have not been taken into account, in accordance with Article 10(3) of the Regulation.
- If necessary, and where timescales permit, consulting a second time, if the response to the first consultation indicates significant problems or where revised proposals are radically different from the original proposals.
- Publishing all ENTSO-E responses to formal consultations carried out by the European Commission and Regulators.

2 PROCEDURAL ASPECTS

2.1 INTRODUCTION

This section provides an overview of the procedural aspects of the network codes' development. It explains the legal framework within which network codes are developed and focuses on ENTSO-E's legally defined roles and responsibilities. It also explains the next steps in the process of developing the OPS NC.

2.2 THE FRAMEWORK FOR DEVELOPING NETWORK CODES

The OPS NC has been developed in accordance with the process established within the Third Energy Package, in particular in Regulation (EC) 714/2009. The Third Package legislation establishes ENTSO-E and ACER and gives them clear obligations in developing network codes. This is shown in Figure 1.

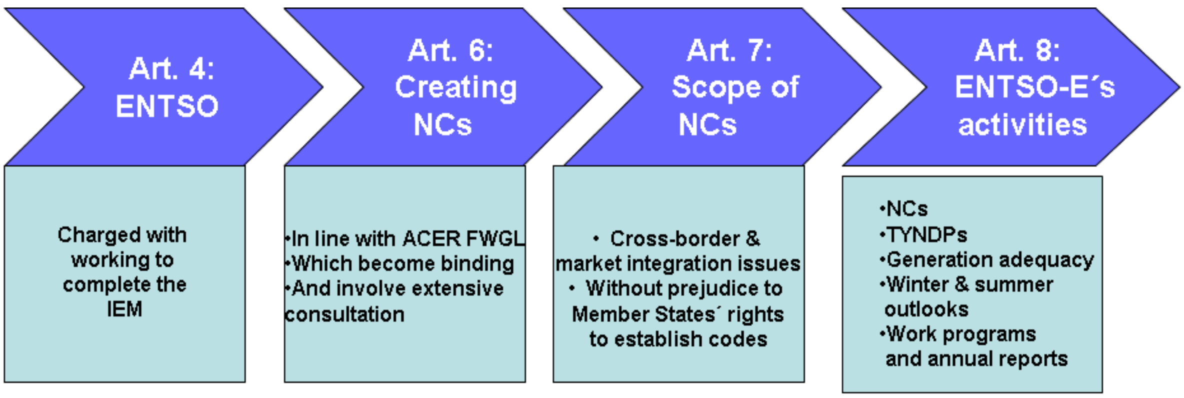

Figure 1: ENTSO-E's legal role in network code development according to Regulation (EC) 714/2009

Moreover, this framework creates a process for developing network codes involving ACER, ENTSO-E and the European Commission, as shown in Figure 2:

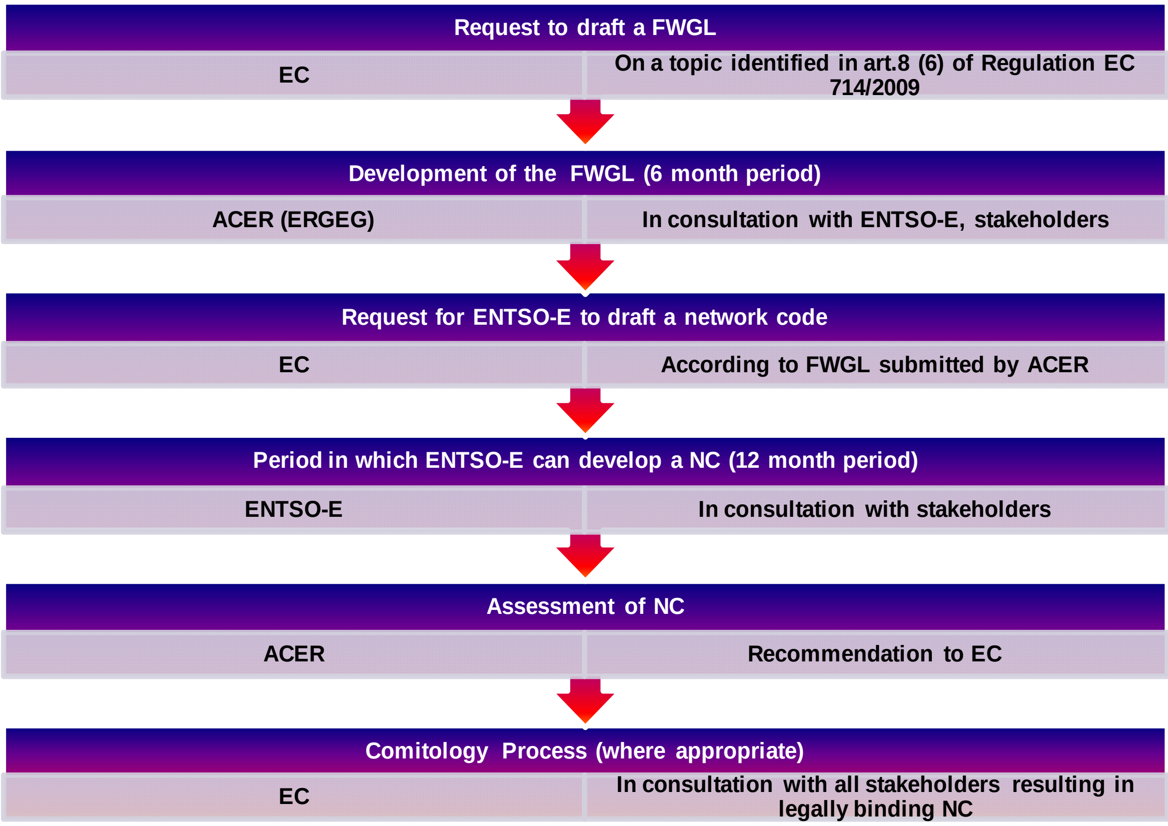

Figure 2: Network codes' development process *(Source: ENTSO-E)*

The OPS NC has been developed by ENTSO-E to meet the requirements of the System Operation Framework Guidelines (SO FG) [1] published by ACER in December 2011. ACER has also conducted an Initial Impact Assessment associated with its consultation on its draft SO FG in June 2011 [2].

ENTSO-E was formally requested by the European Commission to begin the development of the OPS NC on 1st April 2012. The deadline for the delivery of the code to ACER is the 1st April 2013.

3 Scope, Structure & Approach to Drafting the OPS NC

3.1 Purpose and Objectives

ENTSO-E has drafted the OPS NC to define the minimum operational planning and scheduling requirements for ensuring coherent and coordinated preparation of real-time operation of transmission systems in order to achieve and maintain a satisfactory level of operational security of the interconnected transmission systems in real time and to support the efficient functioning of the European Internal Electricity Market (IEM), to non-discrimination, effective competition and the efficient functioning of the IEM.

Based on the SO FG and on the Initial Impact Assessment (IIA) provided by ACER, the OPS NC states the operational planning and scheduling principles in terms of technical needs, considering market solutions compatible and supporting to maintaining the security of supply.

3.2 GUIDING PRINCIPLES

The guiding principles of the OPS NCs are to determine common system operation principles, to ensure the conditions for maintaining operational security level throughout the EU, to provide for coordination of system operation, as well as to determine common requirements to DSOs, power generating facilities and demand facilities connected to transmission and distribution systems, which are relevant for the operational security. These principles are essential for the TSOs to manage their responsibilities for operating the interconnected transmission systems with a high level of coordination, reliability, quality and stability.

The main goal of the system operation NCs is to achieve a harmonised and solid technical framework - including the implementation of all necessary processes required for it, taking into account the rapid growth of the (volatile) Renewable Energy Sources (RES) generation and their impact on system operation. Consequently, the requirements have been designed in order to ensure a secure system operation, taking into account the integration of the RES and the effective development of the IEM.

The requirements set out in system operation NCs on TSOs, DSO and grid users are building upon a long history of existing common and best practices, lessons learned and operational needs throughout the European transmission systems. This, together with the fact that the European experience of interconnected transmission systems operation dates back to the 1950-ies (ENTSO-E Regional Group Central Europe (RGCE), former Union for Coordination of (Production) and Transmission of Electricity (UC(P)TE)), 1960-ies (ENTSO-E North, former Nordel), and 1970-ies (TSO Associations of Great Britain and Republic of Ireland, UKTSOA and ITSOA), distinguishes the OPS NC and all other system operation NCs from other Network Codes in following terms:

- The work on the system operation NCs does not start from “scratch” but builds upon a wide and deep range of requirements, policies and standards of the previous European transmission system interconnections (synchronous areas), adapting and developing further these requirements in order to satisfy the requirements from the SO FG, to meet the challenges of the “Energy Turnaround” including RES and increasing volatility and dynamics of market operations as well as to support effective and efficient completion of the IEM;

- The subject matter – system operation of the interconnected transmission systems of Europe – is vital, not just for the continuous and secure supply of European citizens with electricity but also for the electricity market to function at all. Therefore, any changes, adjustments and developments based on the new (legally binding after comitology) system operation NC’s framework must acknowledge and respect the fact that system operation cannot be interrupted and “restarted” – we are working on a “living grid”;

- By their nature and because of the level of technical detail involving all aspects of transmission system operations, the system operation NCs are mainly addressing the TSOs and ENTSO-E; nevertheless, firm links and cross-references, as well as practical dependencies and explanations are established in relation to other NCs, most notably those addressing grid connection, market and regulating power / balancing.

3.3 BACKGROUND AND STRUCTURE OF OPS NC

Secure and efficient transmission system operation can be made possible, only if there is an obligation for the Transmission System Operators (TSOs), Distribution System Operators (DSOs), power generating facility operators and demand facilities to cooperate and to meet the relevant minimum technical requirements for the operation of the interconnected transmission systems as one entity. Even though each TSO have their own responsibility area, secure and efficient system operation is a common task:

- All systems are to some extent interconnected, and a fault in one area will possibly affect another area. Hence, secure system operation requires close coordination and cooperation.
- Efficient system operation requires close collaboration between all stakeholders; the main purpose of the liberalizing and therefore this harmonizing of the electricity sector was efficiency, and utilizing the resources for balancing the system efficient requires close collaboration and coordination.

Secure and efficient transmission system operation can be made possible only if there is an well-organized preparation of real time operation allowing to have all means necessary to control the system in real time at disposal of the TSO, when it is either subject to normal changes of operation conditions or facing incidents affecting generation, demand or transmission equipment.

OPS NC provides this basis for the preparation as it defines the minimum operational planning and scheduling requirements for ensuring this coherent and coordinated preparation of real-time operation of transmission systems applicable to all TSOs, relevant DSOs, power generating facility operators and demand facilities of significance for the transmission system.

OPS NC covers all planning tasks and procedures required from year ahead to just before real-time. All stakeholders, including TSOs, should respect common requirements for the processes within these different time frames necessary to anticipate real time operation conditions of the interconnected transmission systems and to develop relevant measures required to maintain the operational security, quality and stability of the interconnected transmission system and to support the efficient functioning of the European Internal Electricity Market. These times frames and related processes are the basis for the key elements, structure and provisions of this Network Code, as illustrated in Figure 3 below.

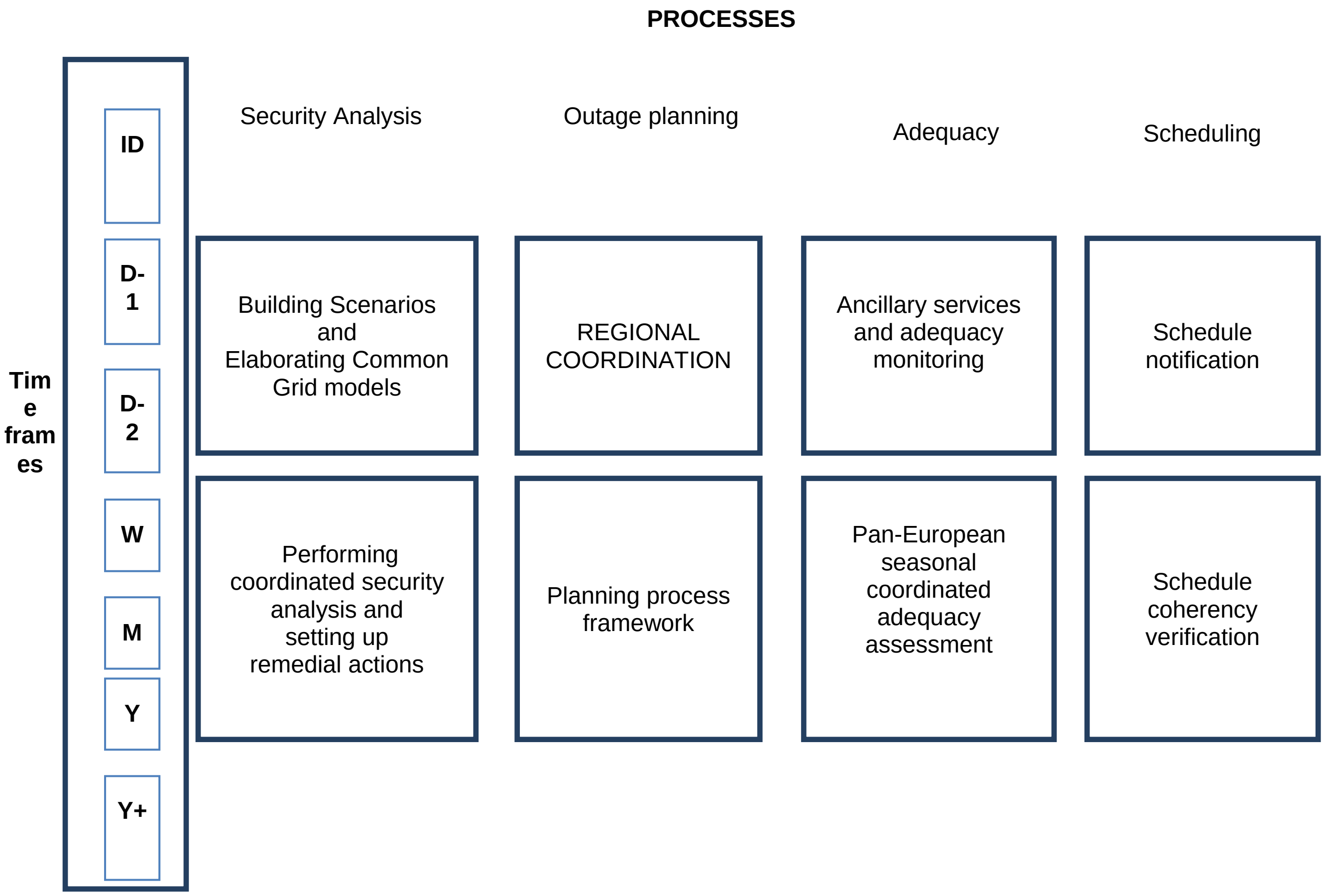

Figure 3: Structure and provisions of the Operational Planning and Scheduling Network Code

The focus of the OPS NC is the following:

- **Building and monitoring scenarios/models within the responsibility areas:** each TSO must implement processes to build scenarios representatives of coming operation environment, within each time frame, based on information inputs between TSOs and, where necessary, DSOs and grid users, taking into account uncertainties on demand, classical generation, renewable, exchanges patterns etc.;
- **Building and monitoring scenarios/models assuring cross border or cross control area coordination:** each TSO should implement process to build, within each time frame, common grid models fitting these scenarios, covering zones allowing coordinated security analysis as congestion and power flow management, including relevant characteristics of the connected generation, consumption and distribution as transmission equipment and taking into account planned outages;
- **Monitoring the system state at all times:** each TSO should implement processes to carry out, within each time frame, on these common grid models, contingency analysis, using simulation tools allowing to assess the state of the system for contingencies as defined by OS NC and to set up required preventive and/or curative actions;
- **Coordinating and monitoring planned outages: e**ach TSO should implement processes to elaborate and update, within each time frame, a coordinated outage plan allowing TSOs, DSOs and grid users to perform and optimize their maintenance works without jeopardizing operational security nor altering the functioning of the electricity market;

- **Monitoring adequacy of power, and both monitoring and acquiring ancillary services: e**ach TSO should implement processes within each time frame to elaborate a coordinated assessment that the power generation capacities will allow to balance the demand as to have the required amount of ancillary services, taking into account planned outages, performing prognoses on uncertainties on demand, classical generation and renewables, as well as the possibilities of cross border exchanges within available transmission capacities. Each TSO must provide the systems and procedures to facilitate an adequate level of ancillary services according to security requirements and should also develop relevant preventive and /or curative measures involve timely and adequate data exchange;
- **Providing procedures for scheduling of cross-border energy exchanges and cross-border coordination of ancillary services exchanges:** TSOs should implement processes allowing the acquisition and coherency verification of cross border scheduled energies exchanges as well as agreed procedures for coordination and exchange of ancillary services in order to use the available resources in the systems effectively;
- **Providing the tools and procedures for scheduling of generation and demand:** the TSO must set up procedures to ensure schedules of generation and demand are provided before real time in order to provide the most efficient basis to allow anticipating real time operational security difficulties.

Based on the above, the following categories of requirements have been established in the OPS NC as chapters:

- Security analysis
- Outage planning
- Adequacy
- Ancillary services
- Scheduling

These subjects will be described in more detail in chapter 5.

3.4 LEVEL OF DETAIL

The system operation NCs provide minimum standards and requirements related to system operation. The level of detail matches the purpose of the codes: harmonising security principles, clarifying and harmonising methods, roles and responsibilities of operators and grid users as well as to enable and ensure adequate data exchange in order to future proof the system for integrating innovative technologies and sustainable energy sources, operate the system in a safe, secure, effective and efficient manner and applying the same principles and procedures for different systems to establish a wider level playing field for market participants.

In order to achieve the necessary level of European harmonisation, allowing at the same more detailed provisions at the regional/national level where necessary, and with the view of drafting network codes for electricity system operation that are open for future developments and new applications, an approach focusing on pan-European view and most widely applicable requirements has been pursued throughout all the development phases.

The SO FG provided further clarification concerning the issue of European-wide applicability, while pointing out that *"… ENTSO-E shall, where possible, ensure that the rules are sufficiently generic to* *facilitate incremental innovation in technologies and approaches to system operation being covered without requiring code amendments"*.

Thus, the requirements have been drafted considering a period of approximately 5 years as a reasonable cycle within which changes to the OPS NC will have to be implemented, building up a coherent legal mechanism with the appropriate balance between level of detail and flexibility, which focuses on what-to-do, not so much how-to-do.

Regarding OPS NC, harmonisation principles are handled through a global framework consisting in the three following levels addressed coherently:

- **European wide level** dealing with building common data set allowing sharing of data, common analyses and common processes defined for operational planning activities articulated on common time frames, including common principals for assessing operational security referring to OPS NC;
- **Synchronous areas level** referring to LFC Network code principles;
- **Regional level** for areas presenting power flow patterns influencing each other, dealing with coordinate planning processes concerning operational security assessment and handling, as well as outage planning.

Regarding methodologies, the approach adopted is to tune the provisions through a global framework giving high level principles and requirements for detailed specifications to be carried out of the code, in a transparent process and leaving place to further evolutions and improvements.

Whereas the first OPS NC picks up as much input from involved parties as possible in order to enable a high level of system security, regional requirements concerning the different synchronous areas, regions or even single TSOs may lead to further and more detailed provisions.

3.5 Future Challenges and Opportunities for System Operation

Today, in line with the challenging objectives addressed in the SO FG, system operation goes beyond just operating the electric power system in a safe, secure, effective and efficient manner. Aspects such as enabling the integration of innovative technologies and making use of information and communication technologies must be fully integrated, while applying the same principles for the different transmission systems of Europe.

In this context, following challenges ahead system operation which are addressed in particular include:

- Effects resulting from fast growth of (volatile) generation from Renewable Energy Sources (RES);
- Needs resulting from the evolution (and completion) of the Internal Electricity Market (IEM).

As the mean to achieve the integration of RES in the system and implementation of the IEM, the following opportunities and risks have been identified as relevant for system operation in an scenario with increasing complexity, where further challenges can be foreseen in the near future due to the new applications and developments on system operation.

- High Voltage DC (HVDC) Links;
- Smart Grids;

- Super Grids.

All five subjects are described below.

Generation from RES

The transmission tasks and challenges within the transmission systems of the European TSOs are ever more driven and influenced by the effects of the growing generation from RES. RES generation predominately varies with weather conditions. The characteristic of variability and also uncertainty, being difficult to forecast accurately, until close to real time of RES generation, causes following consequences for system operation:

- The renewable energy increasingly replaces the feed-in from large power plants directly connected to the transmission system;
- During the several past years volatility of RES generation has contributed significantly to the cross-border power flows increase and volatility, posing therefore new challenges to the required balance between production and consumption;
- The influence of underlying production leads to a high forecast complexity for the balances of transfers into the distribution network and thus also for the prediction of load flows in the transmission system.

This leads to concerns about how to maintain a stable system operation in an electricity network with high penetration of RES. The general answer to this concern is to increase the controllability and the flexibility of all elements of the transmission system. This can in turn lead to a transmission system which can react and cope better with the volatility of RES.

Internal Electricity Market (IEM)

The increasing cross border trades and intraday markets have significantly increased in the recent years, with the corresponding introduction of intraday capacity allocation and the resulting short-term adjustments to the generating capacity of power plants. Due to this fact and in order to comply with the obligations under Regulation (EC) 714/2009, a short-term update of generation forecasts has become indispensable and a reliable system operation can only be established on the basis of reliable input values.

In addition to these consequences for power flows, high changes on generation programs with different rampings (especially non-synchronous rampings) lead to temporary imbalances and create frequency deviation; this phenomena is observed throughout ENTSO-E Regional Group Continental Europe (former UCTE), with an increase of the trend of number, duration, and amplitudes of frequency deviations, especially during the ramping periods in the morning and in the evening[1]. Another observed reason for longer periods with large frequency deviations is persistent imbalance in one or more control areas, which cannot be restored due to insufficient secondary (restoration reserve) and/or tertiary (replacement reserve) control reserve (in these cases the control areas concerned experience a large ACE (Area Control Error)).

These frequency deviations activate a significant share of the primary reserve in the system which is initially intended and dimensioned for coping with very rare and easily predictable (in terms of quantity

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[1] „Deterministic frequency deviations – root causes and proposals for potential solutions", a joint EURELECTRIC – ENTSO-E response paper (NOT FINALIZED)

and risk) generation or load outages, and consequently endanger the secure system operation by limiting the required control reserves for long periods.

Another phenomenon can accentuate these frequency deviations: the fast growth of generation from RES, whereas the generators used (mainly asynchronous by technology) provide no natural inertia frequency response to the system, compared to conventional synchronous generators used in the traditional power plants.

HVDC Links

The operation of HVDC links has to be ensured by TSOs, when these links connects large offshore wind parks to the mainland AC grid and has to be ensured by the owner in other cases (could be a third party). This requires a systematic approach of their reliability when connected to the mainland AC grid and the consideration of the effects of connecting such large amounts of bi-directional power in-feed/out-feed to single points on the operation of the pan-European transmission system. In addition the operational impacts of HVDC also need to be accounted for, with their filter banks, zero fault level in-feed and very fast ramping rates.

The common features of devices such as PST (Phase-Shifting Transformers) or FACS (Flexible Alternating Current Systems) are their controllability and the large impact they have on cross-border power flows also involving HVDC. Nevertheless, these are also opportunities for TSOs to optimise flows and voltages and have to be considered as such. It follows that TSOs have to coordinate the application and operation of PSTs towards coherent and coordinated power flows' control, including also power flows resulting from the HVDC lines.

Smart Grids

Whereas Smart Grids will provide a competitive edge for the IEM focusing particularly at the distribution grids, leading to new products, processes and services, at the same time they will require transforming the functionality of the current transmission and distribution systems to achieve the energy policy targets and to guarantee high security, quality and economic efficiency of electricity supply. Moreover, new developments related to aspects such as communication, especially between DSOs and TSOs, IT-infrastructure and new power system applications must be foreseen.

Taking into consideration the new developments described in this section and its consequences on system operation, the system operation NCs principles set the base of operational rules and of a technical-operational coordination between TSOs, DSOs and grid users in order to deal with issues such as the intermittent generation with low predictability, the massive growth of cross-border trade and transits, generation allocation close to real-time and continuously changing or the high forecast complexities.

Super Grids

Contrary to the smart grids, the term "Super Grids" stands for the developments almost exclusively affecting the TSOs and transmission systems. Whereas the first ideas on a pan-European supergrid date back there to the early 1950-ies, the real needs (i.e. "collecting" and delivering wind power from the North and solar power from the south) emerge only with the "Energy Turnaround". Being a future prospect today, Super Grids – building upon additional and massive AC-lines enforcements, as well as on the HV DC technology – will become reality soon. The system operation NCs provisions must therefore also account for the relevant aspects of the Super Grids, which will be determining the system operation and operational security of the European transmission systems:

- Establishment and usage of the common grid models for all phases of operational planning and real-time system operation;

- Exchange and coordination of all relevant information and data both, between the TSOs and between the TSOs and DSOs and system users; this issue is addressed in detail in the Chapter 2 of the OPS NC;

- Ensuring the provisions and a firm basis for coordinated control actions of all relevant TSOs and DSOs and system users, in order to maintain the global and overall view, while at the same time acting locally or regionally to achieve most efficient and effective results – maintaining operational security and maximizing the welfare from well utilized transmission system capacities.

3.6 INTERACTION WITH OTHER NETWORK CODES

The Operational Planning and Scheduling Network Code (OPS NC) is being drafted in parallel with other related network codes. Several processes, methodologies and standards provided in OPS NC are influenced by or would influence these related network codes and the coordination of the interactions is an important objective of ENTSO-E. The principal cross-issues with other network codes have been dealt with in the following way:

- The Network Codes on *System Operation* – these codes consist of the Operational Security NC (OS NC), the Load-Frequency Control and Reserves NC (LFCR NC) and the OPS NC. The OS NC can be viewed as the ‘umbrella’ code of the system operation network codes. It therefore sets the overall principles for system operation and reflects on the common issues with the LFCR NC and the OPS NC while those will describe their specific processes in greater detail.

- The connection codes (RfG NC and DCC) – connection codes establish the technical capabilities of the generation and demand units connected to the grid. OPS references to them in those provisions in which information related to technical characteristics are required. The translation of technical capabilities described in connection codes to operational criteria is done in the OS NC.

- The network code on *Capacity Calculation and Congestion Management* (CACM NC) – The CACM NC was developed in advance of the OPS NC, enabling the interfaces between the capacity calculation process and system operation to be identified in the early drafting phase of this code. The following separations have been agreed upon: topics related to the physical operation of the power system are covered by the system operation network codes, topics related to the operation of the electricity market are covered by the CACM NC, taking thereby into account the physical risks described in the system operation. A data list containing the information required for building and implementing a Common Grid Model (CGM) has been shared among the CACM NC and the system operation network codes (thus including OPS NC) due to the following reasons: the same CGM before capacity calculation on the different market frameworks is used for the calculation of load-flows in order to carry out network security analysis on the different timeframes of operational planning. During the creation of Individual Grid Models (IGM), OPS NC takes into account updates of several input parameters: e.g. altered outage plannings and agreed upon scheduled exchanges, the latter resulting from long term nominations, day-ahead market coupling, intraday activities and TSO cross border activities as described in the scheduling chapter of OPS NC. Also provisions for constructing 2 days-ahead CGM to calculate capacity, described in CACM NC, are inputs for the construction of day-ahead IGM in order to check in advance its security and to prepare, when applicable, necessary actions.

- *Future network codes* – Particularly challenging is the situation when network codes are not yet under official development: the forthcoming NC's on Balancing (BAL NC) and on Forward

Market are under scoping discussions and especially the latter will cover the capacity calculation and allocation in year-ahead and month-ahead timeframes; timeframes that are also relevant for activities covered in the OPS NC: the updates of year-ahead CGM, as described in OPS NC, would trigger specific security analysis that could lead to updates of planned operational actions to be taken into account in month ahead capacity calculation processes.

3.7 WORKING WITH STAKEHOLDERS & INVOLVED PARTIES

The legally binding nature of network codes, which is achieved through the comitology process, means that they can have a fundamental bearing on stakeholders businesses. As such, the ENTSO-E recognises the importance of engaging with stakeholders at an early stage, involving all interested parties in the development of the code, in an open and transparent manner.

ENTSO-E's stakeholder involvement comprises workshops with the DSO Technical Expert Group and public stakeholder workshops, as well as ad-hoc meetings and exchange of views with all interested parties as necessary.

Due to the many questions concerning the function of the transmission system from an operational point of view that arose during the public consultation of the RfG NC, the first ENTSO-E stakeholder workshop on system operation was held on 19 March 2012 in Brussels. The aim of the workshop was to present information focusing on the operation of an interconnected transmission system, and the physical basis for scoping and drafting the system operation network codes. Stakeholders also had the opportunity to express feedback and expectations.

In line with suggestions by stakeholder organizations and following requests by the EC and ACER, ENTSO-E has envisaged four workshops for OPS NC with the DSOs Technical Expert Group and with all stakeholders both prior to, during and after the public consultation.

The aim of the first OPS NC Workshop, held on the 23rd May was to present and discuss the scope of the draft OPS NC, which reflected the work completed by TSO experts as of 14 May 2012. The workshop addressed the scope of the network code, updated on the present state and allowed for discussion and a Q&A session. Stakeholders in attendance included DSOs, industrial electricity consumers, generators, energy traders and turbine suppliers.

4 RELATIONSHIP BETWEEN THE OPS NC & FRAMEWORK GUIDELINES

4.1 THE FRAMEWORK GUIDELINES

The SO FG focuses on three key challenges, which shall be addressed by four objectives as figure 4 shows.

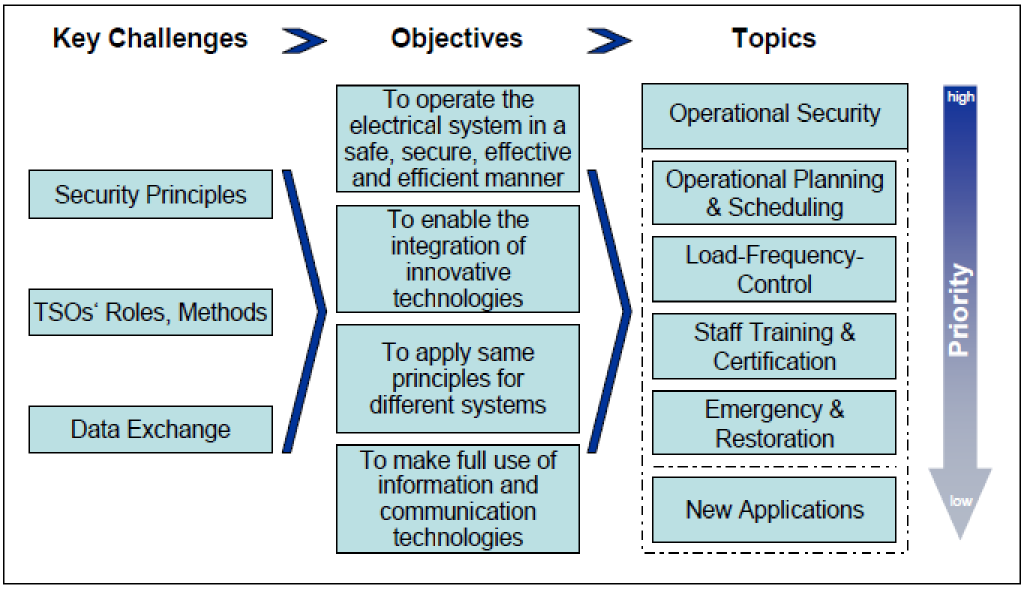

Figure 4. Structure and development flow of the Framework Guidelines on Electricity System Operation

The overall scope and objectives of the SO FG is *"Achieving and maintaining normal functioning of the power system with a satisfactory level of security and quality of supply, as well as efficient utilisation of infrastructure and resources".* Focus in the SO FG are on defining common principles, requirements, standards and procedures within synchronous areas throughout EU, especially regarding the roles of and the coordination/information exchange between the TSOs, DSOs and significant grid users.

The requirements described in the OPS NC have been formulated in line with the SO FG and the new developments on system operation, with the aim to ensure a satisfactory level of operational security and an efficient utilisation of the power system and resources by providing coherent and coordinated preparation of real-time operation.

4.2 Framework guidelines for OPS NC

The OPS NC according to the OS FG defines:

1. Performing of security analyses (contingency analysis, voltage stability analysis, etc.) at each relevant stage of operational planning;
2. Implementation of state estimation, as required for supporting the security control and maintain the operational security, including periodical (with sufficiently short time periods) checks in order to ensure a consistent and errorless input data set for other computations like load-flows, security analyses;
3. Prevention and/or remedy of disturbances and blackouts on incidents which can affect neighbouring areas or the synchronous areas;
4. Scheduling of planned outages and relevant maintenance works of transmission network, significant generation and DSOs' elements, including a coordinated and agreed (among the affected TSOs) scheduling process for long-term and short-term planning;
5. Ensuring of access to an adequate level of ancillary services (e.g. active and reactive power reserves, balancing power) in real-time to meet security criteria and the requirements set at synchronous area level, for each operational planning stage;
6. Exchange of ancillary services across interconnections in terms of technical principles;
7. Coordination of reactive power control with significant cross-border impact;
8. Coordination of short circuit current between TSOs at interconnections;

9. Coordination of commissioning and entering into operation of active and reactive power control network elements with significant cross-border impact. In particular, reactive power control elements installed at each end of cross-border lines shall be coordinated;
10. The principle for the different timeframes for exchange of all necessary information between system operators to handle the different planning and scheduling activities in a coordinated and cooperative manner. This includes all necessary data to construct a proper synchronous area-wide common grid model;
11. The exchange of up-to-date information among TSOs and significant grid users on the development of grid components and configurations, especially as regards planned and unplanned outages and technical ability to provide ancillary services.

5 OPS NC: OBJECTIVES, REQUIREMENTS AND BENEFITS

This chapter describes in more detail the structure and the content of the OPS NC. The OPS NC is built up as the following:

- Purpose and objectives (outside chapter numbering)
- Chapter 1: General provisions (article 1-6)
  - Subject matter and scope
  - Definitions
  - Regulatory aspects
  - Recovery of costs
  - Confidentially obligations
  - Relationship with national law provisions
- **Chapter 2: Data for Operational security analysis in operational planning (article 7-10)**
- **Chapter 3: Operational security analysis in operational planning (article 11-14)**
- **Chapter 4: Requirements for outage planning (article 15-22)**
- **Chapter 5: Requirements for Adequacy (article 23-26)**
- **Chapter 6: Requirements for Ancillary services (article 27-29)**
- **Chapter 7: Requirements for Scheduling (article 30-33)**
- **Chapter 8: Common TSO operational planning platform (article 34-38)**
- Chapter 9: Final provisions

This chapter aims at providing the reader the basis for understanding the requirements set in the chapters marked as **bold** above (of OPS NC), i.e. security analysis (chapter 5.1), outage planning and common TSO operating planning platform (chapter 5.2), adequacy (chapter 5.3), ancillary services (chapter 5.4) and scheduling (chapter 5.5) in that document below.

5.1 SECURITY ANALYSIS

Security analysis is required at relevant stages of the planning process to ensure that system operation is within the normal operating state of the transmission system and that under n-1 conditions as described in the OS NC the frequency, fault level, voltage and load flows etc. remain within predefined limits.

This OPS NC details the responsibilities on TSO's for security analysis, the levels of harmonisation required at the various stages, the framework for the grid modelling and the requirements for data exchange.

The first part of the security analysis chapter describes the principles for constructing and exchanging all necessary information between system operators to perform the necessary security analysis at the relevant timeframes as well as, when applicable, input data for capacity calculation processes.

The second part of the chapter describes provisions for security analysis in the different timescales (year – ahead, day – ahead, etc.) and describes the general provisions for co-ordination of security analysis and remedial actions.

Timeframes contemplated have been the ones in which operational planning activities, other than capacity calculation, are carried out: year-ahead (adequacy outlook, yearly outage plan) and its updates, week-ahead (typical timeframe for outages programming), day-ahead and intraday.

The main objectives of the chapter are to detail:

- The requirements for data exchange, as with other parts of the OPS network code accurate and timely provisions of data is of the utmost importance.
    - o Provisions to ensure pan-European harmonisation, with the construction and update of year-ahead common grid models for the whole pan-European system, based on harmonised scenarios.
    - o Provision of day-ahead and intraday individual grid models, harmonised at least at synchronous area level, will include meaningful data from the market, predictions of uncertainties and results of scheduling activities performed by TSOs in order to ensure the accurate data needed to perform security analysis.
- The requirements for performing security analysis, in line with methodologies standardised at least at synchronous area level, at each relevant stage of operational planning, ensuring that the system operation meets security criteria under simulated operating conditions and the secure energy exchange between different control areas.
- Requirements for ensuring the coordination in operational planning, including contingencies and constraints evaluation and remedial actions and covering reactive power control and short circuit coordination.

The majority of requirements for TSO's, DSO and grid users in this topic are building upon existing best practices and lessons learned: data exchange and day-ahead congestion forecast models have already been developed and built in Continental Europe and that experience will be beneficial when developing the models described in this NC.

The integration of renewable energies and the assessment of the uncertainties associated with them which is detailed in this NC also builds on existing best practice and lessons learned. Existing practices in several areas, based on a combination of the establishment of appropriate requirements for renewable generation, together with the centralised and real time update of its forecasted production and the capability to be controlled, have demonstrate their efficiency.

The new and enhanced requirements under this topic in the OPS NC are:

- The procedures for constructing pan-European year-ahead common grid models and relevant information.
- Improvement of quality of data used to construct the grid models, including:
    - o long term estimations of market participants, and
    - o specific attention to forecast of renewable energy production and distributed generation.
- Methodologies standardising the principles for operational security analysis at least at synchronous area level (nevertheless Operational Handbooks do already exist in each synchronous area).

The OPS NC is compliant with the requirements placed on it by the FWGL. It is to be mentioned that the basis for the determination of the harmonised methodology to calculate the necessary reliability margin to cope with uncertainties relevant to the system operation is not here developed, since all provisions for calculating reliability margin have been described in the NC CACM. Reliability margin is related only to the capacity calculation and for allocation of capacities to the market. Security analysis is done within operational security limits.

NRA or ACER approval has been provided for methodologies in those topics that required it, in particular:

- Principles for categorisation and applicable methodology governing remedial actions shall be approved by NRAs.
- Costs of remedial actions shall be recovered in accordance with the principles approved by NRAs and in compliance with EC Regulation 714/2009, Art. 16(6).
- All TSOs shall submit, not later than 24 months after the entry into force of this Network Code, to ACER a methodology, harmonised at least per synchronous area, for operational security analysis.

5.2 OUTAGE PLANNING AND COMMON TSO OPERATIONAL PLANNING PLATFORM

To prepare operation of the electricity grid, outages of grid elements, generation facilities and demand facilities have to be planned. This chapter provides a common European framework to perform these planning activities with harmonized deadlines, data exchanges and coordination requirements. The outage planning process starts on the year ahead timeframe, where the basis for the coming year is established. After being finalized, the year ahead outage plan can be updated by all parties up to real time. Once real-time operations are reached, agreed upon outage plans should be honored by all parties, and unplanned events are to be handled.

The described outage planning process is centered on being reciprocal for all parties, enforcing transparency between parties to allow preparation for a safe operation of the grid and an optimal functioning of the electricity market.

The principal in year ahead outage planning is shown below in Figure 5. Deadlines are set to ensure that relevant and necessary information about planned outages is available, when it is needed for linked processes (for example security analysis, system adequacy assessment and capacity calculation).

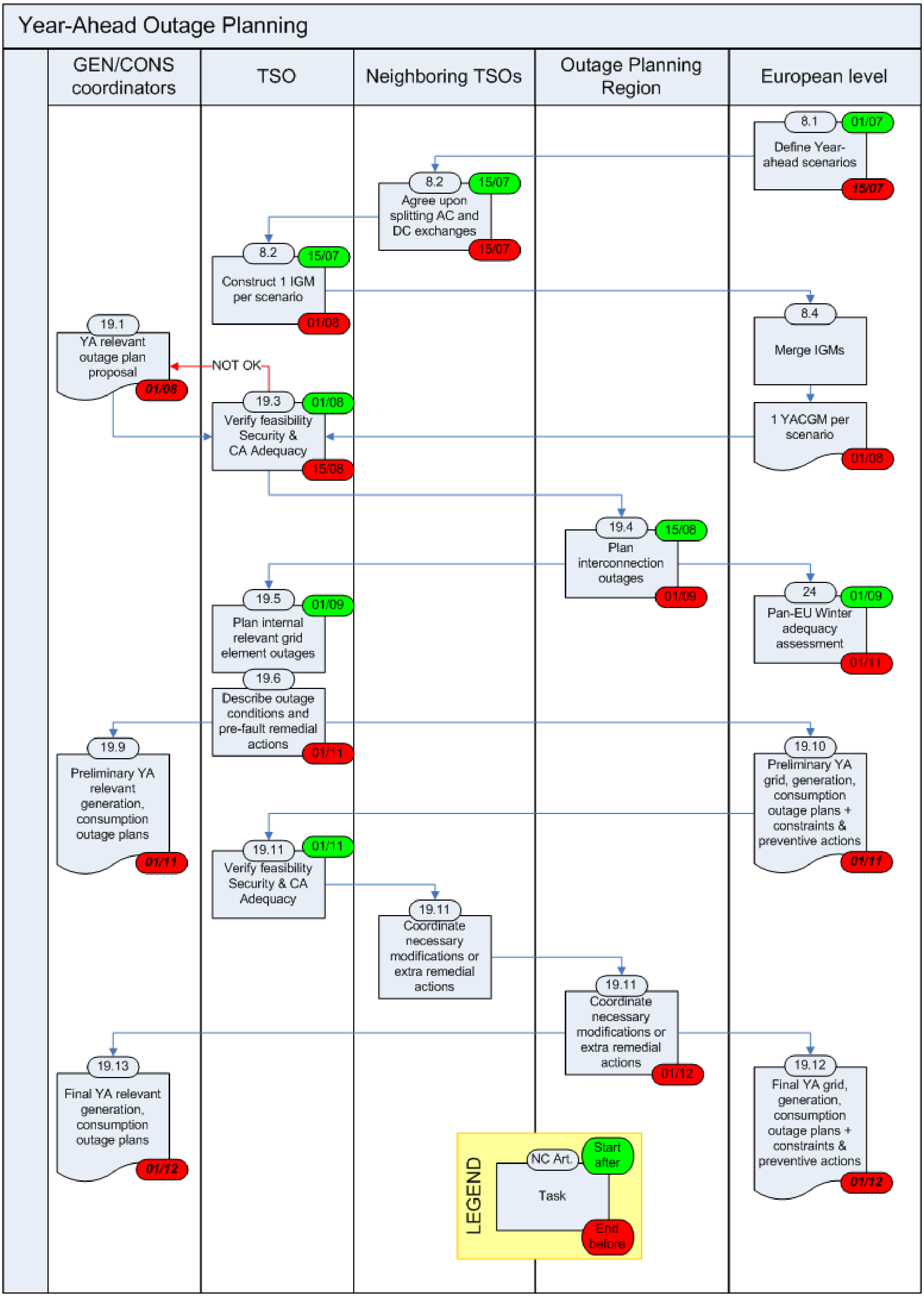

Figure 5. Overview of the outage planning processes in OPS NC.

Figure 5 depicts the flow and sequence of tasks to be executed in the framework of the year-ahead operational planning process. It allows the reader to appreciate the links between different processes and requirements described in this network code, and gives an overview of the deadlines to be set at the different process blocks to achieve a consistent and feasible year-ahead planning process. Among all deadlines shown on the diagram, only those in boldface and italics are incorporated in the network code. This ensures that crucial data is available at the right moment and leaves the flexibility to plan all processes in between these dates as efficiently as possible. Other dates are given as an indication of a possible timeline for the entire process.

One of the main drivers in the timeline of this process is the pan-European system adequacy assessment for the winter season. This study allows the TSO(s) to assess the forecasted adequacy for the coming winter. As it takes into consideration the energy flows between coupled markets in different parts of Europe, this European assessment becomes very rapidly a crucial element in forecasting system adequacy.

After a very recent exercise, the time necessary to collect data, run simulations, analyse results, and prepare and validate reports for this adequacy assessment was reduced to a process of about two months. As results need to be available early November at the latest, this means that the inputs for this study have to be available early September. Crucial inputs relating to the outage planning process described in this network code are planned outages of interconnectors (to take into account the possibility to transport energy between areas) and planned outages of power generating units.

Another driver in the timeline is the process of determining long-term cross-border capacities. To start this process, outages of critical branches as well as outages of power generating units should be known.

To allow these two main drivers to be executed with a decent accuracy, combined with the time intervals necessary to complete all data gathering, calculation, analysis and coordination tasks incorporated in the year-ahead process, the given dates and deadlines were established. We think these common deadlines represent a crucial factor in the pan-European harmonization of the electricity markets, and are indispensable for allowing an improved coordination between all parties active in these processes.

The general framework of the described planning process is based upon the current best practices installed in the EU.

The coordinated outage planning process as described is standardized EU-wide, with the same deadlines, data provision requirements and roles and responsibilities for every relevant party operating in the EU.

For practical reasons, a division into outage planning regions is made to organize the practical execution and coordination of the outage planning. These outage planning regions are constructed to reflect clusters of systems with large mutual impact. In the situations where this is necessary coordination between outage planning Rrgions is enforced.

Relevant information is shared between TSOs not only on a regional level, but on the EU-wide scale through the means of a common TSO platform. Every TSO is obliged to put and update his data (regarding outage information) under a common format on this platform, where it is accessible by all EU TSOs and regional coordination initiatives. This principle allows a TSO to filter the data that is deemed relevant for its purpose, with the access to the full EU-wide dataset if desired.

The code is applicable in the EU, without exceptions.

Currently no single centralized data platform exists for sharing relevant information concerning outage planning between TSOs. Having such a data platform should greatly ease and stimulate collaboration and coordination between TSOs, provides a transparency platform where needed information can be found on request, and enforces TSOs in using common data formats, common timelines and – to a certain level – common methodologies.

The outage planning process, with its deadlines, responsibilities, data exchanges and coordination actions is established in several requirements. Currently there is no such harmonized basis on the European level, and differences exist between countries and/or regions. To provide a common, uniform basis is however necessary in creating a level playing field for the European electricity market.

Currently, in different countries, the process of establishing the year-ahead up to day-ahead availability plans for generation and consumption greatly differs. How the TSO intervenes in this process varies between the extremes of being a mere observer to being capable of fully steering generation and consumption outage plans. As one of the main objectives is to stimulate the functioning of the European electricity market as much as possible meanwhile guaranteeing security of supply; the way the process is drafted ensures the following:

- In the year ahead planning stage, generation and demand facility operators are free to plan (un-)availabilities according to their desires and optimize their portfolio.
- The TSO will assess if an issue arises with these combined proposals regarding operational security. At this point in time no grid outages are planned yet, so they do not interfere with generation and demand facility outage proposals.
- If incompatibilities arise, all affected parties enter a coordination step. If no feasible alternative can be decided upon, the only option to guarantee operational security is by modifying the proposed outage plan. The affected generation and demand facility operators will be asked to provide the TSO with an alternative outage plan relieving the detected incompatibilities.
- After this step, grid outages are planned by the TSO. In case of incompatibilities with generation and/or demand facility outages, the TSO shall coordinate with the relevant parties to find a negotiated solution.
- After the year-ahead outage plan is finalized, all parties can request changes to this outage plan. These changes will be approved unless operational security cannot be guaranteed under the combination of the requested change and the already existing outage plans.
- Next to these planned updates, unplanned updates can occur. If so, the relevant party should inform all impacted parties as soon as possible, and do its utmost to limit the consequences for the electricity market as much as possible.

Except in case of 'overmacht/force majeure' or if security of supply is at stake, the established outage plan should be honoured in real-time.

The outage planning process – or more in particular the results thereof – supports the real-time operation of the grid, and is therefore implicitly linked with all operational codes. A direct link with CACM and forward codes can also be distinguished, as planned outages are a key factor in the determination of cross-border exchange capacities.

5.3 ADEQUACY

System adequacy deals with the ability of a power system to supply the load in all the steady states that the power system may face.

The OPS NC especially sees a task in making sure that the following TSO-functions can be fulfilled: balancing generation and cross border exchanges with load including netlosses; safeguarding and restoring the system; and controlling frequency and voltage.

The majority of requirements set out on TSOs, DSO and grid users in this topic are currently used pan-European system adequacy outlook and existing best practice of bilateral coordination.

Specific requirements for pan-European adequacy analysis are foreseen to be set by all TSO in methodology.

Regarding data, day-ahead congestion forecast models are already built and improved in Continental Europe and that effort could serve as useful experience for the models described in this NC.

The integration of renewable energies and the assessment of the uncertainties associated to them is not either a new topic. Practices in several areas, based on a combination of the establishment of appropriate requirements for this specific generation, together with the centralised and real time update of its forecasted production and the capability to be controlled, have demonstrate their efficiency.

The level of harmonization is twofold: 1) a pan-European adequacy analysis season ahead is foreseen; 2) all other analyses are an update to this season adequacy and are performed on a responsibility area level, whereby, if applicable, neighboring TSO's are taken into account. It is widely considered that this twofold methodology is sufficient to cover all pan-European operational needs.

There are none not applicable parts in the Adequacy section.

General requirements are set for TSO to perform national updates of pan-European adequacy analysis afterwards and to coordinate with relevant TSO in case of significant changes in generation availability or on load.

The added value of these new requirements are that each TSO will be able up to real time to, in a coordinated way, review and monitor the adequacy status of its system taking thereby imports/exports into account.

The requirements currently set out the present draft of the OPS NC do not differ or deviate from the requirements set out in the Framework Guidelines on System Operation.

The requirements currently set out the present draft of the OPS NC has a relationship with the transparency Guideline, section 7, article 1, but no link to other system operations network codes is foreseen.

5.4 ANCILLARY SERVICES

Ancillary services are services provided by grid users to the TSO. In the OPS NC ancillary services refers to active power, reactive power and black start. The two former ancillary services enable the TSO to operate a secure and reliable power system, whereas the latter enables the TSO to reset the system after a fault. Focus is on active and reactive power, since black start will be included in more detail in emergency code.

In managing the transmission systems, the TSOs must be able to deal with unexpected changes of generation capacity, interconnector flows or system demand. This is accomplished by maintaining a prudent level of active power ancillary services. The OPS NC puts the responsibility on the TSO’s to ensure the correct procurement and management systems are put in place to ensure adequate/correct ancillary services.

The correct levels of active power ancillary services are set by calculations within the LFC NC. The OPS NC recognizes the need to plan ahead to ensure the correct levels of active power ancillary services will be available once real time is reached. Updates to this plan will be required for any significant network or generation changes that impact on operational security. If when updating the plan a shortfall is detected, remedial action shall be taken. OPS NC recognizes that if a TSO finds itself in a shortfall position (after remedial actions have been investigated), communication and cooperation with neighboring TSO's is a priority.

For reactive power, the TSOs must maintain a voltage balance across the transmission systems in order to maintain a secure and stable power system and to avoid damage to connected equipment. To maintain the balance, the appropriate level of reactive power (leading and lagging) is required at appropriate locations in the transmission system. The required level of reactive power varies in the operational timeframe. Reactive power is mainly provided by generator units and transmission assets. Generally, reactive power must be provided close to the location where it is needed. Overall, therefore, the requirement is for the flexible provision of reactive power at appropriate points across the transmission systems. Similar planning concepts apply to the management of reactive power ancillary services as for the management of active power ancillary services, as laid out within OPS NC.

The OPS NC also recognizes that within the heavily interconnected networks of the EU, system operation is no longer a national issue. Secure and efficient system operation demands cross-border and cross-control area coordination. Hence, there is a need to share information on ancillary services across interconnectors in the planning phase to ensure that everything reasonably practical has been done to ensure both operational security and an economically sound outcome.

The majority of requirements set on TSO's, DSO and grid users in this topic are based on best practises and lessons learned.

The level of harmonization is high and not so detailed, since procurement of ancillary services differ to a large extent country to country as well as the OPS NC on this point is close connected to NC on Balancing and NC LFCR, which provides more details.

The code is applicable in all areas due to the high harmonization level.

The section adds general requirements concerning cross-border coordination of ancillary services in order to facilitate closer collaboration TSO-to-TSO.

Closer collaboration enables a more efficient and economic system operation, meaning maintaining the same system security at lower costs. This also future-proofs the system, making sure a high amounts of renewables can be integrated in the system to lowest possible costs.

The ancillary service section of OPS NC is closely linked to LFCR NC and NC on Balancing.

5.5 Scheduling

Schedules are a tool for the TSO for planning system operation after market closure before real time. The schedules are the agreed plans from generation and consumption units as well as interconnectors and hence they provide the necessary information for the TSO to operate the system. The schedules are the backbone of balancing the system; the sum of schedules in one control area should equal zero within a time period, leaving the system in balance providing no faults occur and both consumption and production equals the prognosis. Hence, the schedules provide the TSO(s) with valuable insight and enable him to balance the system in real time with a minimum level of reserves for balancing compared to the extensive level of reserves necessary had he no schedules.

The schedules provide the TSO with valuable insight; if the schedules do not equal zero, the TSO has time to inform the market players of potential mistakes proactively instead of experiencing potential enormous imbalances real time. This is both economical as well as it increases security of supply.

The scheduling chapter of OPS NC sets the requirements for the scheduling process for exchange of energy between TSO/TSO and TSO/market participants to ensure the schedules provide the data needed for the TSO(s) to run the system in a secure and efficient manner.

The majority or requirements set out on TSOs in this topic are based on existing and best practice.

In general, the level of harmonization is high and allows local market rules to decide the specific scheduling requirements in each control area. Requirements for TSO-TSO are slightly more specific, still allowing for local interpretations.

The code is applicable in all areas due to the high level of harmonization.

Scheduling in “net positions” (output of the market coupling process) sets up a new requirement for the Market Coupling Operators. They shall support the process that ensures that all external schedules between market balance areas are balanced. This is also foreseen in the ENTSO-E Continental Europe reporting process. Scheduling in “net positions” sets up a new requirement for TSOs operating a market balance area.

The benefit of this new requirement is that potential imbalances are discovered before real time, enabling the TSO to proactively take measures instead of discovering huge imbalances real-time, hence preventing potential blackouts caused by market miscommunication/mistakes.

The requirements currently set out in the present draft of the OPS NC do not differ or deviate from the requirements set out in the Framework Guidelines on System Operation. OPS NC shall describe the principles for exchange of all necessary information between system operators. Scheduling is the backbone of doing so in the planning phase, after market closure before real time.

The requirements currently set out in the present draft of the OPS NC are related to the CACM, LFCR and Balancing network codes.

6 Literature & Links

[1] “Framework Guidelines on System Operation” (FG SO), ACER, 2 December 2011.

[2] “Initial Impact Assessment”, ACER, June 2011.