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EDITORIAL

The first paper is entitled as "Use of Flexibility in Distribution Networks: an Overview of EU and Croatian Legal Framework and Trends". This paper reviews the mentioned possibilities of using flexibility in the distribution network and proposes the process of DSO request to own, develop, manage or operate energy storage facilities, and DSO access to flexibility. The main purposes of flexibilities within distribution system are deferral of grid reinforcements, optimization of operational performance of assets and reducing grid losses by influencing the peak load. It is stated that several technologies can provide flexibility, including centralized or de-centralized generation, demand side participation and energy storage but only very large customers find it easy to sell their flexibility on an individual basis and participate in the flexibility market today.

The next paper is "Calculation of Lightning and Switching Overvoltages Transferred through Power Transformer". Since all primary HV equipment installed in the power system is subjected to transients during their lifespan, it is necessary to adequately dimension and protect the equipment. The paper presents a high-frequency power transformer model. The transformer model is developed in the software tool for the calculation of transient phenomena. The model is verified and then simulations of transferred lightning and switching overvoltages are given for the observed power transformer unit. Through detailed simulations and modelling of all other components in the transformer station, it is possible to check the magnitude of the overvoltage, the effectiveness of the overvoltage protection and the possibility of resonance occurring at different switching and operating conditions in the network.

The third paper is "Prioritizing Diverse Observations or Issues from Safety Reviews at Nuclear Power Plants According to Possible Safety Impacts". Considering the fact that any nuclear power plant (NPP) is, over its operating lifetime, permanently subject to numerous safety reviews with different scopes and objectives, this paper discusses types of different observations or issues which may come from general or targeted safety reviews. Safety issue generated by a review are characterized in terms of the three general attributes and described. It is worth noting that the ranking process presented in the paper is relative, meaning that the final result is a list of safety issues sorted by predefined significance.

The fourth paper is "RELAP5/mod3.3 Analysis of Natural Circulation Cooldown with One Inactive Loop for Nuclear Power Plant Krško (NEK)". The article analyzes the limiting cooldown rates during operator recovery actions to minimize the effect of flow stagnation in inactive loop. However, the Westinghouse method 3 for determining limiting cooldown rate cannot be applied to NEK with adequate confidence, so the specific analysis was performed using RELAP5/mod3.3 computer code. The reasons can be found in the different steam generators compared to standard Westinghouse SG types. The obtained results show that the cooldown rate shall be significantly reduced what was expected according to the analysis assumptions and, also, to a certain extent, due to the physical characteristics of NEK steam generators.

The last paper is "Improvement Possibilities for Nuclear Power Plants Inspections by Adding Deep Learning-based Assistance Algorithms Into a Classic Ultrasound NDE Acquisition and Analysis Software". It focuses on the safety of nuclear power plants. The work presented in this paper shows a part of the project that aims to develop a modular ultrasound diagnostic NDE system for applications in hazardous environments within nuclear power plants. It shows how the software part of this system can reach near-total automation by implementing various deep learning algorithms as its features and then, testing those algorithms on laboratory samples, showing encouraging results and promises of online monitoring applications.

Igor Kuzle
Editor–in–Chief

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Use of Flexibility in Distribution Networks: an Overview of EU and Croatian Legal Framework and Trends

Minea Skok, Lahorko Wagmann, Tomislav Baričević

***Summary* — The new Croatian Electricity Market Act (in force since October 22, 2021 [1]) stipulates that the distribution system operator is encouraged to use flexibility, including participation in congestion management in distribution network in coordination with transmission system operator, to increase efficiency, develop the distribution system and promote energy efficiency measures. DSO can access flexibility in one or more of the following ways: market-based procurement of flexibility services, distribution network tariffs, flexible (non-firm) connection agreements, rules based (regulated) approach, in combination or separately. The categories are not necessarily mutually exclusive and the inherent regulatory incentives and implemented measures may overlap. Member States and national regulatory authorities should, therefore, carefully evaluate the interactions when implementing new forms of access to flexibilities or when enhancing existing ones. The paper reviews the mentioned possibilities of using flexibility in the distribution network.**

***Keywords* — flexibility, distribution networks, network tariffs, active system management, efficient network development**

I. Introduction

An increase in the share of renewables has created and will continue to create challenges for the energy system. These challenges include frequency variation, insufficient capacity in the networks, excessive voltage swells/drops, overloading of network equipment, outages and inefficient resource handling. Increasing and promoting flexibility in the grid could be a cost-effective way to minimize the challenges that come with renewable energy production and new forms of consumption.

The main aim of distribution system operators (DSO) and regulatory authorities (RA) is to maximize the efficiency of the distribution network, by utilizing the existing and future infrastructure to its full capacity. The use of flexibility to maximize the efficiency of the grid could provide socio-economic benefits by utilizing existing resources that could decrease or defer the need for new investments in grid infrastructure.

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On an individual level flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) to provide a service within the energy system. The parameters used to characterize flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc.

Flexibility is of particular importance to the DSOs because most of the distributed generation and new loads are connected directly at the distribution level. In essence, if the DSO use of flexibility would make the current grid last longer by requiring less infrastructure upgrades or reinforcements, while at the same time achieving better voltage quality and continuity of supply, there is the potential to better utilize and efficiently develop the distribution system. The utilization of flexibility in the distribution system can fulfil several purposes, such as:

- Reduce or defer required network reinforcements;
- Active congestion management, allowing alternatives to curtailment;
- Reduce or shift demand or generation profiles to smoothen the load shape;
- Better management of power quality issues, such as those relating to voltage swells/drops, harmonics, flicker, and asymmetry.

The flexibility can be acquired from the planning stage, and later be used during the system operation. As given in 2020 CEER Paper on 'DSO Procedures of Procurement of Flexibility' [2], management of the distribution network constraints/limits can be divided into the following categories:

- Grid capacity management;
- Congestion management;
- Voltage control.

Grid capacity management involves planning and realization of network investments according to predefined criteria and the respective regulatory framework. Capacity constraints can result in incidental or frequent temporary overload or congestion, but in contradistinction to *congestion management* (which usually provides temporary solutions), it should in the future be considered business as usual. DSOs may use the explicit, or even some forms of implicit, demand-side flexibility to increase their operational efficiency without any impact on the freedom of dispatch, trade and connections (copper plate principle).

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Flexibility mechanisms are divided into (Figure 1):

- Implicit, where actors respond to fixed price signal, e.g. spot price in wholesale market or tariff set by DSO;
- Explicit, where the actors themselves bid in their price and actively contribute to the price formation.

Explicit Flexibility
is committed, dispatchable flexibility that can be traded on the different energy markets (wholesale, balancing, non-frequency ancillary services markets).
This is usually facilitated and managed by an aggregator or on an individual basis (larger businesses and industrial sites). This form of flexibility is often referred to as "incentive driven".

Implicit Flexibility
is the consumer's reaction to price signals.
Where consumers have the possibility to choose hourly or shorter-term market pricing, reflecting variability on the market and the network, they can adapt their behaviour (through automation or personal choices) to save on energy expenses.
This type of flexibility is often referred to as "price-based".

Fig. 1. Types of flexibility

The main purposes of flexibilities within distribution system are deferral of grid reinforcements (especially relevant for (but not limited to) grid areas where n-1 obligations apply), optimization of operational performance of assets (e.g. extending the lifetime of the component) and reducing grid losses by influencing the peak load.

Congestion management refers to avoiding the overload of system components by reducing peak loads to avoid failure situations or outages. This process addresses, contrary to *grid capacity management*, the overload situations that have not been anticipated during the long-term grid planning process, or situations where grid reinforcements cannot cope with the load/ generation increase. Such measures provide a temporary solution, where the long-term solution (in general) is grid reinforcement. In the future, to fully harness the potential of flexibility, *grid capacity management* should be considered as business as usual for the DSO, contrary to *congestion management*. Both services, when designed as an explicit, market-oriented mechanism, could have different tailored products (short term – energy products or long term – capacity products that may be combined with energy products), but are aimed at solving or preventing active power overloads.

Voltage control (mostly depending on active power in lower voltage levels) addresses problems with power quality, e.g. occurring when production (mostly generated by distributed renewable energy sources (RES)) significantly exceeds the demand in the observed time interval with the result of an increased voltage level in the (local) grid. Using demand-side flexibility to impact the load/ generation can avoid exceeding any voltage limits and consequently reduce the need for grid investment (such as automatic tap changers) or prevent generation curtailment.

Article 32 of the Directive (2019/944) [3] on common rules for the internal market of electricity sets new requirements on the use of flexibility in distribution networks. For the procurement of flexibility services, the way that the DSOs describe their needs and how this is signaled to relevant market parties and other actors are of particular importance because this has a significant influence on the market outcome. The specifications of network needs might differ substantially depending on grid topology, customer basis and locational cause of congestions. The different needs in the grid could require different solutions and various types of access to and use of flexibility.

Several technologies can provide flexibility, including centralized or de-centralized generation, demand side participation and energy storage. However, only very large customers, e.g. industrial customers, find it easy to sell their flexibility on an individual basis and participate in the flexibility market today. Smaller residential and commercial customers may face high barriers in accessing these markets. Transaction costs of such participation are too high if managed at individual level. Aggregation is a commercial function of pooling de-centralized generation and/or consumption to provide energy and services to actors within the system. It offers the opportunity for smaller residential and commercial customers to exploit their flexibility potential. Aggregators can be retailers or third parties. They may act as an intermediary between customers who provide flexibility (both demand and generation) and procurers of this flexibility. They would identify and gather customer flexibilities and intermediate their joint market participation. This could be done via flexibility products or simply by selling and buying aggregated energy (kilowatt-hours) at optimal points in time.

The provision of ancillary services including services for congestion management by grid users connected to the distribution system has been the core of numerous research and development projects as well as recent regulatory developments in some European Member States. There has been a significant number of research initiatives over the past years. In late 2021 Joint Research Centre (European Commission) – JRC, has published report "Smart Grids and Beyond: An EU research and innovation perspective" [5] in which an analysis of investments in (realized or ongoing) smart grid R&I projects has been made. Projects relevant to flexibility are categorized as "smart network management" and "demand side management". They focus on increasing the operational flexibility of the electricity grid through enhanced grid monitoring and control capabilities and on facilitation of demand flexibility (demand response) respectively, and which, according to [5], gather 40% of the total funding. As observed in [4], local flexibility markets and flexibility in general are not so far from the infancy stage in the real-life. On the other hand, both academia and R&D oriented departments in the commercial sector are active in exploring various high-RES penetration models, flexibility provision, TSO-DSO coordination schemes and distribution level market models. Among surveyed papers, we single out the following works that provide overview of the most advanced and promising projects and platforms: [4, 5, 7, 8]. Even though the literature provides insights on current state, what lacks is the pilot project and research on applicability in different markets around Europe. Local and national pilot projects are good steps forward as they allow testing of different strategies within a fast-evolving framework.

II. The Croatian Law on Electricity Market (2021) – Flexibility and Ancillary Services at the Distribution System

The market-based approach, meaning DSO procurement of explicit flexibility, is a relatively new field despite regulations in many EU countries neither disincentivizing nor explicitly forbidding such access. Recently adopted Croatian Law on Electricity Market [1] stipulates that the regulatory agency should provide incentives to DSO to procure flexibility services, including congestion management in coordination with the transmission system operator (TSO), in order to improve efficiencies in the operation and development of the distribution system, and to promote the uptake of energy efficiency measures (Article 75, paragraph 1).

The Law prescribes that in the Distribution network code DSO shall prescribe the technical criteria for the provision of ancillary and flexibility services (Article 75, paragraph 3).

In line with the CEER Conclusions Paper "Flexibility Use at Distribution Level" [9], the Croatian Law recognizes four different mechanisms for DSO's access to flexibility (Figure 2): Rule based approach, Connection agreements, Network tariffs, and Market based procurement.

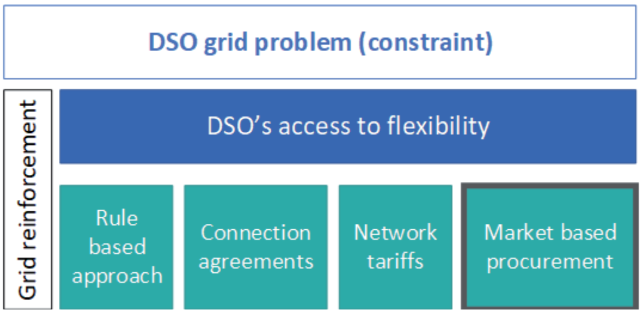

Fig. 2. Different ways of accessing flexibility for DSO - the Croatian Law on Electricity Market, Article 75

Constraint management consists of several methods to handle challenging grid situations (Figure 2). As a starting point, DSOs can manage constraint issues with the activation of their own flexible grid assets. Such actions are a default option and applied before or at the same time as considering market-based management. If a DSO cannot solve a problem with its own assets (e.g. topology changes, tap changers, voltage boosters, etc.) it may need to invest in new assets (grid reinforcement); the procurement and use of flexibility for constraint management could be the better solution economically.

The regulatory framework ensures that DSO can procure services from providers where such services cost-effectively alleviate the need to upgrade or replace assets in the grid and support the efficient and secure operation of the distribution system (Figure 3). DSO shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion. In other words, the EU Electricity Directive states with an "*argumentum e contrario*" that the flexibility procurement must be economically efficient and must not lead to severe market distortions or to higher congestion. Consequently, this inverse conclusion shows that market-based flexibility procurement presents the base-case to be implemented, but also must not come at any price, e.g. if congestions are increased as a result. Thus, there may be cases where it is decided at national level to not implement the market-based approach. In this regard, the Croatian Law (Article 75, paragraph 4) obliges DSO to perform the cost/benefit analysis based on which the regulatory agency shall decide on the exemption from the market-based procedures.

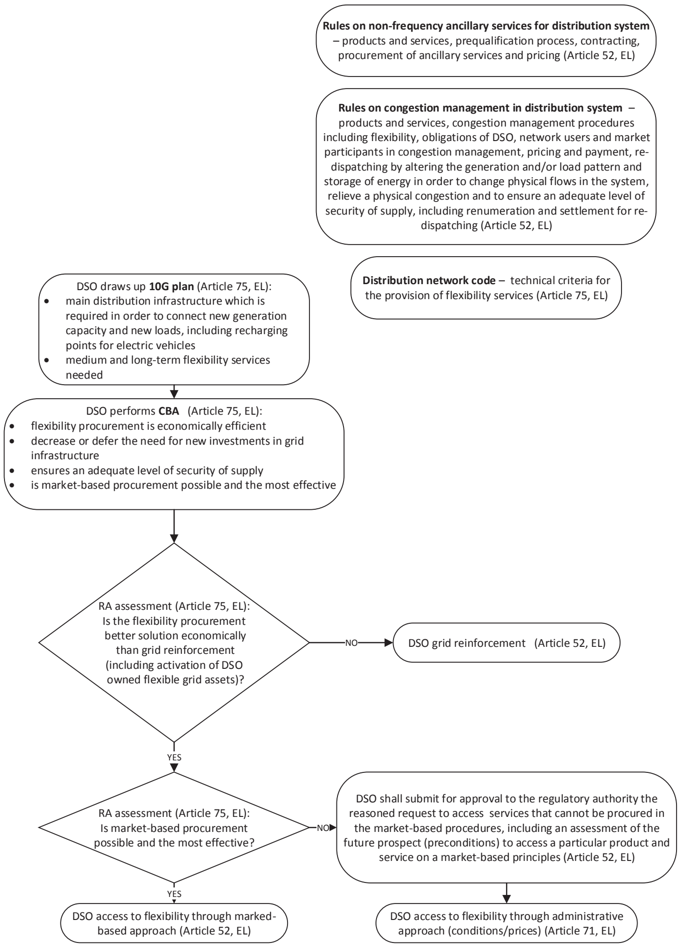

Fig. 3. The Croatian Law on Electricity Market (EL) – DSO access to flexibility

By September 30 each year DSO shall submit for approval to the regulatory authority the reasoned request to access flexibility and non-frequency ancillary services that cannot be procured in the market-based procedures, including an assessment of the future prospect (preconditions) to access a particular product and service on a market-based principles.

The Law (Article 75, paragraph 8) states that every year the DSO shall draw up and publish a transparent network development plan (10G plan) and shall submit it to the regulatory authority which may request amendments. The 10G shall provide transparency on the medium and long-term flexibility services needed and shall set out the planned investments for the next ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the DSO is to use as an alternative to system expansion.

The Law (Article 52, paragraphs 22-26) also prescribes that the DSO shall procure the non-frequency ancillary services needed for its system in accordance with transparent, non-discriminatory and market-based procedures, unless the regulatory authority has assessed that the market-based provision of non-frequency ancillary services is economically not efficient and has granted a derogation. Subject to the regulatory approval, by the end of the October 2022 DSO should have adopted rules on non-frequency ancillary services for distribution system in which at least the following shall be provided: products and services, prequalification process, contracting, procurement of ancillary services and pricing.

The Law (Article 52, paragraphs 31-35) prescribes that the DSO shall engage in flexibility services, including congestion management. The DSO congestion management rules shall prescribe at least the following: products and services, congestion management procedures including flexibility, obligations of DSO, network users and market participants in congestion management, pricing and payment, re-dispatching by altering the generation and/or load pattern and storage of energy in order to change physical flows in the system, relieve a physical congestion and to ensure an adequate level of security of supply, including renumeration and settlement for re-dispatching.

III. Implicit Flexibility through Network Tariffs

Network tariffs typically have three main components, used either alone or in combination: fixed (€/point of delivery); capacity (€/kW); and volume (€/kWh). Common charging bases include flat rate and non-linear rates varying with volume or time of use. The advantages and disadvantages of each tariff component and each charging basis are discussed in [10] and are summarized in Table I.

Table I. Tariff components and charging bases [10]

Tariff component	Fixed	Capacity		Volume
		ex ante	ex post	
Advantage	• Simple • Stable • Predictable	• Signals that capacity has a price	• Signals that capacity has a price • Cost-reflective	• Acceptable to consumers
Disadvantage	• Does not signal long term costs and so does little to encourage energy efficiency and system flexibility	• Reflect capacity costs to a limited extent	• Requires smart metering • Complex • Less predictable • Less acceptable to consumers	• Does not reflect capacity costs • Can raise revenue uncertainty for DSOs
Tariff charging basis for capacity and volume components	Flat rate	Non-linear	Time-of-Use	
			static	dynamic
Advantage	• Simple • Acceptable to consumers	• Can be designed to balance multiple objectives of affordability, conservation, efficiency and cost recovery	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits engaged consumers financially	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits engaged consumers financially • Can target specific system events on short notice
Disadvantage	• Less cost-reflective • Can over-incentivize self-generation which does not always synchronize with system peaks	• Complex • Potential adverse consequences due to poor design or consumer understanding	• Predicted peak times may not coincide with actual system peak • Does not allow for variability when peak conditions occur	• Requires advanced metering • The risk of all consumers responding simultaneously to a single price signal • Traditional consumers who cannot change consumption pattern may face higher prices

Power consumption is not the only determinant of the level of network costs. As the network requires enough capacity for peak consumption, the time-of-use is also important to consider. Time-differentiated “static” tariffs (TOU, Figure 4) are characterized by offering different price signals for energy and power, based on discrete time periods (or “time-bands”) that are fixed in advance, possibly differing between relevant locations on the network. Generally, with time-differentiated static tariffs the time periods and the price signals themselves do not change for several years. Time-differentiated static tariffs offer a reasonable balance between efficiency and complexity, but lack the most desirable advantage of dynamic ToU tariffs, i.e. short-term changes in prices, reflecting the actual network conditions. This is especially true when actual critical peak hours are highly volatile.

Time-of-use, whether energy, power or any mixture are generally considered to be more cost-reflective than time independent tariffs, as they are aligned to predicted peak times. However, static time-of-use differentiated tariffs could also pose a challenge if they lead to large loads being shifted in and out of the network simultaneously (e.g. at the change of hours). For example, such shifts could happen when the price variation in the energy charge is high between two hours and an increasing degree of home automation results in a large number of users responding at once. Tariffs giving such signals could lead to new network peaks. The aforementioned situation could be solved by using automation and gradual consumption management.

A dynamic ToU tariff means that the price signal is defined at shorter notice, possibly close to real-time. This contrasts with static ToU tariffs, where the price signals are associated with predetermined time periods. Dynamic ToU network tariffs are one way that DSOs could (implicitly) make use of flexibility to avoid or defer reinforcement. The objective of a dynamic ToU network tariff is to promote more efficient network use under a scenario where network use has become more uncertain (e.g. due to intermittent production or new consumption patterns) and where new technological solutions are enabling demand response (smart meters, automation, storage). Being dynamic, the price signals can be sent closer to real time, increasing the cost-reflectiveness of the network tariff, which should result with a more cost-efficient system, benefitting all network users.

A first step for a more dynamic ToU network tariff is providing price signals that reflect the critical periods that need to have significantly higher prices. Critical peak pricing (CPP, Figure 5) is a dynamic form of a time-varying tariff, where the peak price would be significantly higher on a limited number of days (typically 10 to 15) or hours per year, when the capacity of the system is most likely to be constrained (i.e. critical events), and lower for the rest of the year. The dynamic nature of a CPP rate allows the utility to respond with short notice of an upcoming “critical peak period”, during which tariffs will be significantly above normal. Peak time rebates (PTR, Figure 6) are in some ways the mirror image of a CPP rate.

Studies [11] have shown that CPP tariffs provide incentives for customers to change their consumption pattern. Results from France, Great Britain, Slovenia and Japan show that customers react on CPP pricing, which means that the peak load can be reduced. Plans to introduce or actual implementation of CPP tariffs can be found in countries including Slovenia, China, USA, Japan and France. For example, in France, time-of-use and variable-peak signals have been used for 50 years.

A PTR provides consumers with a payment for reductions in consumption below a predetermined customer level baseline during peak events. PTR is popular since it is a “no-lose” tariff for customers (in the short-term at least). However, accurately forecasting customer baseline usage is not trivial.

Real-time pricing (RTP, Figure 7) provides consumers with an hourly or sub-hourly price. While RTP is typically used to capture hourly variation in wholesale energy prices, theoretically, real time pricing of the network (under which the tariff is dynamically set) may be possible, although it has not been implemented anywhere on the distribution network. As the amount of intermittent generation capacity from wind and solar generating sources increases, distribution system capacity constraints may become less predictable and hence rate designs that can respond to actual system conditions (such as RTP or CPP) rather than reflect stable patterns (such as TOU) may become more valuable.

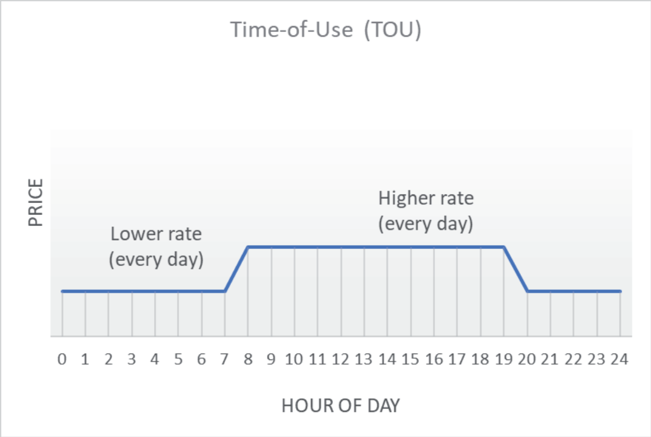

Fig. 4. Illustrations of alternative time–varying rates – Time-of-Use (TOU)

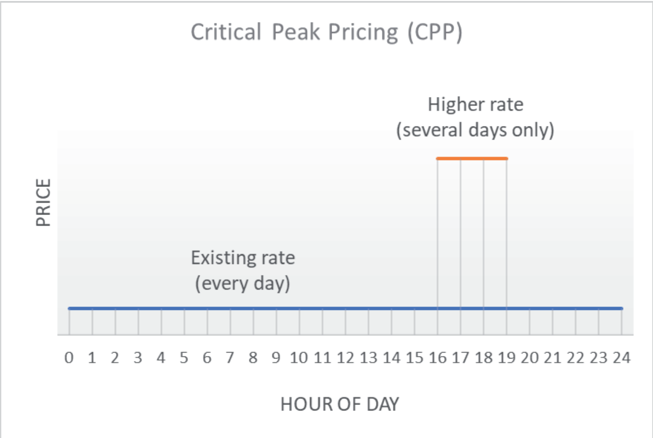

Fig. 5. Illustrations of alternative time–varying rates – Critical Peak Pricing (CPP)

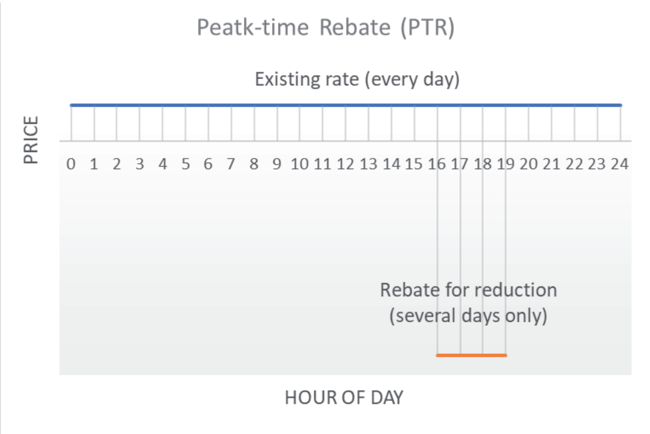

Fig. 6. Illustrations of alternative time–varying rates – Peak-time Rebate (PTR)

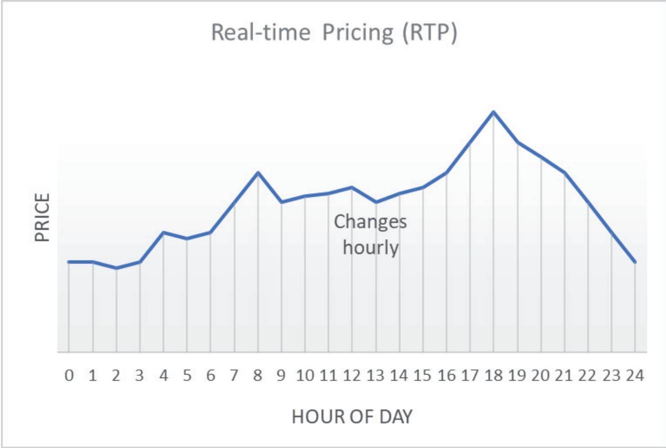

Fig. 7. Illustrations of alternative time–varying rates – Real-time Pricing (RTP)

The introduction of dynamic ToU network tariffs shares the same pre-requisites as (envisaged by the Electricity Directive [3]) dynamic retail prices, namely:

- Introduction of smart meters in order to measure consumption in short time intervals, according to the time unit, as determined by the imbalance settlement period. This is on track across Europe with the widescale roll-out of smart meters. For the status of the rollout of electricity smart meters at the end of 2021 see the ACER/CEER report [12] and for the progress on national smart meter roll-outs see article published in January, 2022 [13];
- Feedback about metering data to enable a user to control their energy use (e.g. through an app or a technical device). This is the stated intention of the Clean Energy Package [14];
- Technological solutions for flexible use and power reduction within property, housing and industry (e.g. automation and storage);
- A detailed forecasting model, which would be used by the DSOs to determine the critical periods by network area/point. Notably, DSOs need to become increasingly engaged in active grid management, and this includes modelling of future congestions;
- IT infrastructure to send price signals to network users, possibly differentiated by network area/point, in order to ensure users are able to predict charges and respond to them;
- Robust estimates about long-term avoided costs.

In general, dynamic ToU network tariffs would be far more complex in comparison to static ToU network tariffs. In [11] CEER emphasizes that principles such as simplicity and predictability are especially important for small customers, while other principles have more weight for larger customers at the DSO level. Besides, the introduction of dynamic ToU network tariffs raises numerous regulatory questions. These issues include how customers should be informed of tariffs, how regulators should regulate tariff setting, and how they should be integrated into the system of tariff or revenue cap incentive regulation (when applied). Finally, through the resulting tariffs it should be ensured that a reasonable distribution of costs among all network users is achieved, especially between customers with and without automation. If a high degree of cost recovery is done through the dynamic tariff signal, costumers who are unable to respond through technology are likely to pay higher network costs. This depends on a number of aspects, e.g. on whether the dynamics ToU network tariffs are voluntary for customers and how the costs would be distributed between dynamic and static tariff users.

For the beneficial network behavior of network users important is the interaction between both static and dynamic ToU network tariffs and the procurement of flexibility. Combined with static ToU network tariffs, the impact of flexibility procurement should be easy to identify. Provided the procured flexibility is contracted for a sufficient period of time, the procuring network operator will be able to avoid network expansion. This leads to an overall reduction of the DSO's costs in most cases in the long run. Thus, network users will be charged lower tariffs than would have been the case without the procured flexibility. Where tariff static time signals do not prompt the desired demand response, the procurement of flexibility forms a beneficial instrument for avoiding costs. This creates the potential to use flexibility, while allowing network tariffs to fulfil the tariff principles of simplicity, predictability and non-discrimination.

More complex is when flexibility procurement is considered alongside dynamic ToU network tariffs. Dynamic ToU network tariffs and flexibility procurement differ in that under the procurement of flexibility, the DSO explicitly contracts for it with the customer or their intermediary, while with dynamic ToU network tariffs, the flexibility provided by customers is implicit. Thus, the effectiveness of the latter firstly depends on the actual existence of customer flexibility and, secondly, on the interaction between the network tariff signals and other behavior-influencing factors.

CEER [11] emphasizes that worldwide there is limited experience of full dynamic ToU network tariffs at the distribution level. Nonetheless, there are a couple of observations that can be made, when they are compared with the procurement of flexibility. First of all, the effectiveness of both instruments might currently be limited at the DSO level, as it depends on the potential for flexible behavior. For small customers, such as private households and small businesses that are mostly connected to the low voltage level, it might be questionable whether there are currently available sufficient (technological) possibilities for providing flexibility. The complexity of dynamic ToU network tariff calculation is also an important factor when discussing the potential effects of dynamic tariffs and flexibility procurement being applied simultaneously. Realizing the benefits of dynamic ToU network tariffs is even more complex when explicit flexibility is applied, because the interaction between both instruments makes the effects of any behavior change in response to tariffs harder to predict. Under a system of continuously changing tariffs and network load situations, it will be very difficult to effectively allocate and (subsequently) apply explicit flexibility. This again might lead to problems regarding location decisions, e.g. for new storage facilities.

As observed by CEER [11], for now a combination of procurement of flexibility and maintaining static time-of-use tariffs where needed would be more suitable, at least until the level of automation for customers at lower voltage levels has reached sufficient maturity.

IV. Congestion Management

According to the definition [15], congestion management is activating a remedial action to respect operational security limits. Congestion is a condition (forecasted or realized) where one or more constraints (thermal limits, voltage limits, stability limits) restrict the physical power flow through the network. Network congestion occurs because the hosting capacity of a given grid is limited by the inherent characteristics of physical assets (i.e. lines, cables, transformers). Congestion in the distribution network is caused by voltages exceeding the allowed limits or overloading of the network components. Thus, congestion management is mitigated by voltage control or by load/generation control. In the context of DSO congestion management, the focus of this paper is on physical congestions. These are defined by EU Directive [15] as "any network situation where the forecasted or realized power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system".

Furthermore, there is a distinction between two types of physical congestion:

- Structural congestion, which is defined as congestion in the distribution or transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions; and
- Sporadic congestion, which can be defined as an unpredictable congestion that is not stable over time and can occur under any system condition.

Higher utilization of the distribution grid increases the risk of more frequent congestion and leads to an overall system operation with lower capacity margins. This constitutes an increased need for local system services to handle constraints at specific locations in both meshed and radial networks. Key prerequisites are sufficient observability (meaning the DSO's information regarding the known and forecasted state of its own grid) and controllability (to assure correct activation of flexibility from network users).

In short, the term observability describes DSOs' abilities to determine the current and coming state of their networks through models comprised by static data on components and topology, planned changes, prognostics and real-time measurements. With a sufficient level of observability, DSOs can detect where congestions might occur in short or longer terms, based on calculations and observations. Hence, determining within a variable time frame where they need to reinforce the grid and/or how to procure flexibility.

Controllability refers to DSOs' ability to control their own and other assets remotely or manually, either individually or in combination with the actions of network users and system operators at their interface. This activation can be performed directly or through indirect (intermediary) measures. DSOs usually coordinate the operation of their networks from a control center.

Congestion management measures in the distribution network can be divided into preventive ones – non-costly measures and remedial (curative) - costly measures. Using calculation tools and data collected by SCADA, DSO can predict congestion (thermal and voltage) in network components in different time frames, year, month, week or day in advance. Such predictions are more reliable with the availability of information, such as weather forecast and measured values (loads and voltages). As a starting point DSO will try to prevent expected congestion by network reconfiguration and voltage regulation on transformers. If a DSO cannot solve a problem with its own assets it will rely on the curative/remedial measure of congestion management: the use of flexibility and re-dispatching.

The vital part in real-time operation, after forecasting the capacity margin and setting the expected congestion size on particular nodes, is the actual activation of a given resource while ensuring that the delivery is sufficient to handle the congestion. It is important that the controllability of flexible resources is thoroughly tested going through an agreed product prequalification process. Control centers can thereby gain sufficient experience before wide-spread deployment. To ease the transition towards more active system management, DSOs might, as a starting point, prefer the possibility to access and activate flexible resources directly from their control centers instead of being dependent on intermediaries. A more advanced (and necessary) step would be activation through intermediaries, for instance flexibility market platforms and aggregators, which is for some DSOs already business as usual and state of the art in TSO grids.

V. Energy Storage Facilities

A significant penetration of energy storage will be one of the crucial factors for integrating more renewable energy into the power system, because it enables a combination of intermittent RES with rather inelastic demand, while meeting the technical requirement that power supply matches demand at all times.

Regulation (EU) 2019/943 [16] establishes that "network charges shall not discriminate either positively or negatively against energy storage". Since a storage facility may withdraw energy from or inject energy into the distribution network, it can be regarded as both a consumer and a producer located at the same network connection point. As such, non-discrimination would suggest that energy storage should be subject to distribution tariffs applicable to both energy withdrawals and, where applicable, energy injections. Notwithstanding this, the cumulative charges for withdrawal and injection must reflect the value of storage to the system. A storage facility operated with the purpose of improving network utilization can decrease the need for future network investment, while a storage unit operated inefficiently from a network perspective can increase future distribution costs. The distribution tariff design should be able to reflect the positive or negative impact that storage facilities might have.

In practice, there will not only be standalone storage facilities, but also storage that could be combined with withdrawal or injection (or both) behind a single point of connection. In the short run, behind-the-meter storage will probably increase more than network-scale storage solutions. Also, energy storage is likely to develop further where there are explicit instruments of flexibility procurement for them.

Regulatory authorities should review whether their current tariff design, with special attention to volumetric charges, is providing adequate incentives for storage equipment or equivalent network utilization, such as self-consumption or energy communities. CEER recommended [11] that net metering for self-generators and storage facilities should be avoided.

VI. Ownership of Storage for DSO

By the Croatian Law on Electricity Market (Article 79, paragraph 1) [1], DSO shall not own, develop, manage or operate energy storage facilities.

This prohibition, however, comes with a double derogation possibility; DSO may own, develop, manage or operate energy storage facilities:

- where they are fully integrated network components and the regulatory authority has granted its approval or,
- where a series of (cumulative) conditions is fulfilled including a tendering procedure as well as ex-ante review and approval by the regulatory authority. Decisions to grant a derogation also must be notified to ACER and the EC.

Fully integrated network components can include energy storage facilities such as capacitors or flywheels which provide important services for network security and reliability of the transmission or distribution system, and not for balancing or congestion management.

The conditions for the second derogation are threefold:

- other parties, following a tendering procedure (subject to review and approval by the regulatory authority) have not been awarded with a right to own, develop, control, manage or operate such facilities or could not deliver these services at a reasonable cost and in a timely manner;
- such facilities are necessary for the DSO to fulfil their obligations under the Croatian Law on Electricity Market for the efficient, reliable and secure operation of the distribution system and they are not used to buy or sell electricity in the electricity markets; and
- the regulatory authority has assessed the necessity of such derogation, has carried out an ex-ante review of the applicability of a tendering procedure, including the conditions of the tendering procedure, and granted its approval.

Figure 8 outlines authors view of the approval process of DSO request to own, develop, manage or operate energy storage facilities in Croatia.

Here is worth to add that the drafting of new EU network code on demand side flexibility is in the process which will aim at enabling market access for demand response, including load, storage and distributed generation (aggregated or not), as well at facilitating the market-based procurement of services by distribution and transmission system operators. In this regard in the ACER draft framework guidelines on demand response [17] the novelty is explicit possibility of shared ownership with a third party (i.e. the storage facility may be owned and operated partly by system operator, partly by a third party). Besides storage facilities owned and operated by a third party, shared ownership is to be defined as a mandatory option for system operator to consider, as part of the tendering process.

The Croatian Law on Electricity Market also includes an obligation for regulatory authority to perform at regular intervals (at least every five years) a public consultation to assess for existing storage facilities the potential availability and interest of market parties to invest in such facilities, in view of a phase-out of DSO energy storage activities (in which case the regulatory authority also must ensure phase-out within 18 months). Hence the Law entails several new duties for regulatory authority, including approval (Figure 8), assessment and phase-out tasks.

Based on JRC survey [18], eight out of thirty-nine (20 %) EU DSOs have mentioned about the ownership of a storage system. In terms of size of these systems, apart from some systems which have been installed during pilot projects in which the DSO was involved (500kW, 2MW, 2,5MW), DSOs which have a storage system in place indicate a capacity size below 100kWh and usually are distributed through substations for powering transformers equipment during outages or for customer powering during critical situation, which is in line with the provisions specified in the EU Directive 2019/944.

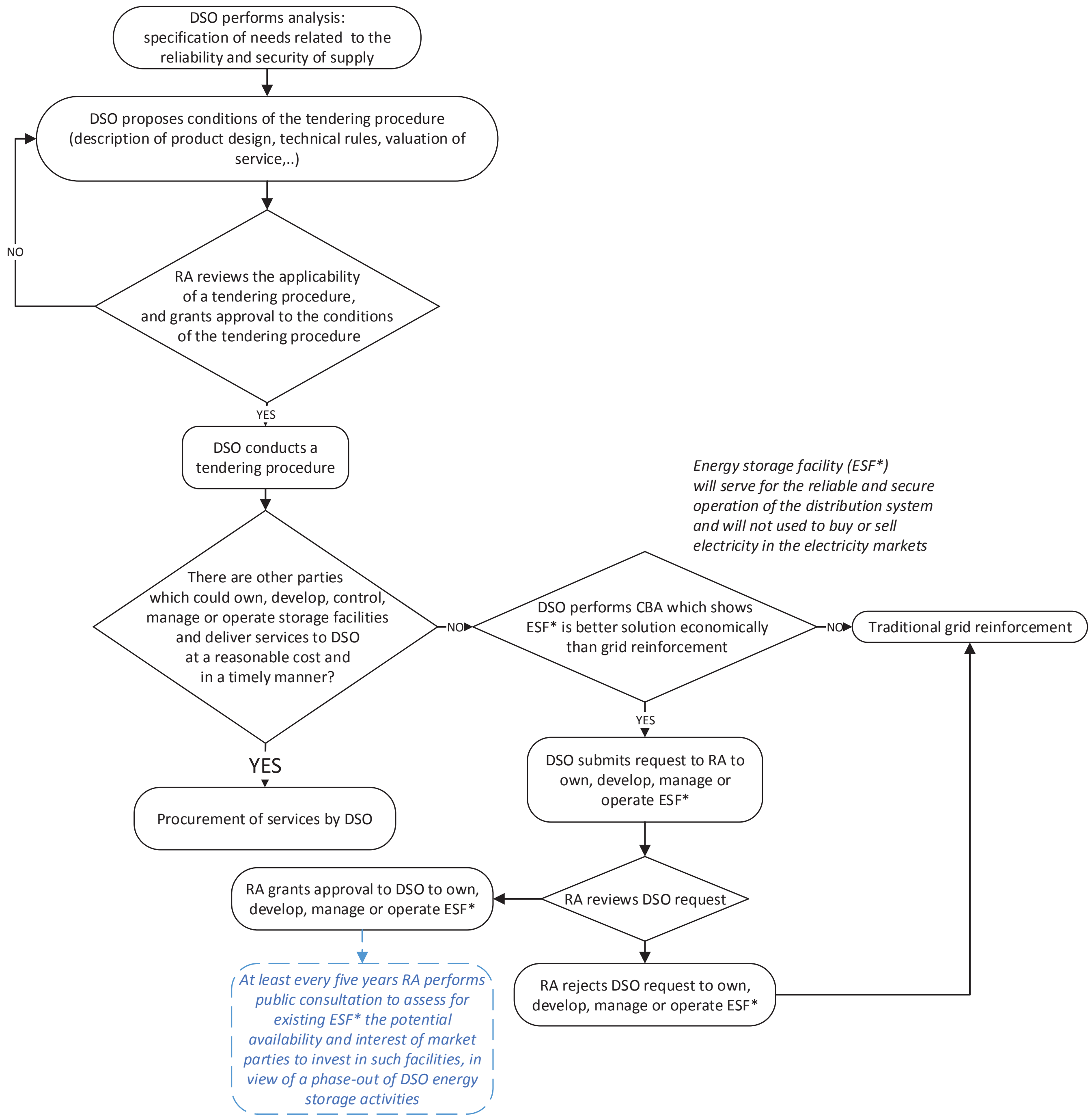

Fig. 8. DSO request to own, develop, manage or operate energy storage facilities approval process – derogation from Article 79, paragraph 1 of the Croatian Law on Electricity Market [1]

In most cases (81%) no specific connection and access rules are in place for energy storage systems. Based on connection charging methodology adopted in August 2022 [19], energy storage facilities (ESF) in Croatia are subject to specific shallow policy; i.e. applicant ESF is not charged for reinforcements to the existing system but only for the immediate connection assets. Also, ESF in Croatia is subject only to withdrawal charge [21], which is the approach applied in 50% of EU jurisdictions (in 30% of EU jurisdictions ESF are subject to both injection and withdrawal charges and in 20% are fully exempted from network charges).

VII. Flexible Connection Agreements

Connection agreements that DSOs need to offer to system users across the EU have generally concerned agreements with firm capacity rights. This implies that system users should be able to access their contracted capacity for the full 100% all of the time. The gap between available network capacity and connection requests has recently widened significantly and is expected to grow on a larger and larger scale. As a result, in more and more instances, third-party access to the transmission or distribution network cannot be granted (be it for demand or generation or a mixture thereof) because of a lack of network capacity (calculated at present grid standards and based on present grid connection rules).

Flexible connection agreements can generally be thought of as a deviation of this firm capacity right on different dimensions: they may vary from firm capacity rights that are valid part of the time (i.e. time-specific) to non-firm capacity rights all of the time.

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Until recently, flexible connections, non-firm access or interruptible capacity contracts - all of these terms referring to a connection capacity agreement where the rights granted are in some aspect (time or capacity or other) limited - were rather an experimental, exceptional solution to this problem and could not be considered the norm. Flexible connection agreements are a possible way to fit new users into a network where there is not full capacity available at all times. They might be applied either as an interim solution to defer grid reinforcement or under certain specific conditions as a long term remedy.

The first approach increases grid use efficiency until grid development. In order to solve the capacity problem, grid operators have to reinforce their grids. Network reinforcements generally take quite some time causing long waiting times for parties that are seeking access to the grid. Until the grid is reinforced, it is desirable that the existing grid capacity is used as efficiently as possible. For example, grid capacity is often still available outside peak times. However, this requires a certain degree of flexibility from system users, and might not be an interesting or viable option for all system users as their supply and/or demand is inflexible; e.g. Ofgem (UK) did not consider flexible connections suitable for small, domestic households.

What makes flexible connection agreement increasingly popular is that as opposed to the extremity of having or not having a firm capacity agreement, it introduces a scale in between. Each grid user can therefore decide, whether it prefers a quicker or cheaper connection with certain limitations, or pays and waits for a firm connection.

EU Directive 2019/944 (Article 42) [3], with regard to the decision-making powers regarding the connection of new generating installations and energy storage facilities to the transmission system, stipulates that the TSO shall not be entitled to refuse the connection on the grounds of possible future limitations to available network capacities, such as congestion in distant parts of the transmission system.

The Croatian Law on Electricity Market [1] the aforementioned obligation stipulates not only to TSO (Article 12), but also to DSO (Article 72). This shall be without prejudice to the possibility for DSO to limit the guaranteed connection capacity or to offer connections subject to operational limitations, in order to ensure economic efficiency regarding new generating installations or energy storage facilities, provided that such limitations have been approved by the regulatory authority.

The newly adopted Rules on general conditions for network use and electricity supply [20] (in force since October 2022) allow that the use of network agreement may comprise provisions regulating operational limitations as an interim solution, with a clearly defined duration and the mutual rights and obligations of the system operator and network user. The conditions of the operational limitations shall be determined in the process of connecting and shall be comprised in distribution connection agreement. New Rules on connection to the distribution network shall prescribe determining the conditions for operational limitations.

In addition to the Rules on connection to the distribution network, the new Rules on congestion management in the distribution system (should have been adopted by the end of October 2022) shall provide implementation details, while ensuring that any limitations in guaranteed connection capacity or operational limitations are introduced on the basis of transparent and non-discriminatory procedures.

VIII. Incentives for the use of flexibility in distribution networks

As observed by CEER [2], when planning, expanding and managing their networks DSO may either opt for the use of greater network expansion with less need of flexibility or less network expansion with a greater need of flexibility. The level of security of supply and other criteria (e.g. unrestrained interconnection of RES) must be guaranteed according to national obligations. The details of the regulation and the lawmakers' provision to necessary grid expansions, including potential degrees of freedom for the DSO on network dimensioning, determine the direction of the system operator's approach.

If a DSO decides to design the network with scarce capacity, meaning lower capacity margins, there is a greater need to carry out congestion management procedures. In this case, the DSO incurs the cost of payments to third parties for their contribution to relieving congestion. Congestion management costs are classified as operational expenditures (OPEX), whereas network expansion costs are classified as capital expenditures (CAPEX), Figure 9.

Of relevance here is how these costs are treated and remunerated in the regulatory scheme comprising the total cost of expenditures (TOTEX), Figure 10. In Croatia, the recognized costs method is currently applied with a regulation period of one year. A high weighted average cost of capital (WACC) will encourage DSO to increase investments since it will be reflected in justified expenditures in the form of a higher return on equity (refund). On the other hand, in the case of a multi-year regulatory period, the increased OPEX (due to the expenditures for services) will occur in the revenue allowance with a certain lag.

In addition to traditional grid reinforcements, regulatory authority should acknowledge that there are alternative solutions to efficient provision of network services, for which more tailored remuneration schemes are needed. Through a risk incentive, the regulatory authority should recognize that there could be different levels of risk for DSO to opt for a service like flexibility rather than traditional grid reinforcement, which is a safer option. Indeed, traditional grid reinforcement has well-known outcomes such as lower losses, greater reliability, ability to quickly connect new loads, provision of rapid increase in capacity, higher short circuit levels and greater voltage regulation. The regulatory authority should consider the transfer from a solution with known expense (CAPEX) to one comprising both capital and operational expenditure with a highly variable expense (flexibility as OPEX) and that penalties for non-delivery of contracted flexibility may not fully cover the incurred costs in case the provision of flexibility fails.

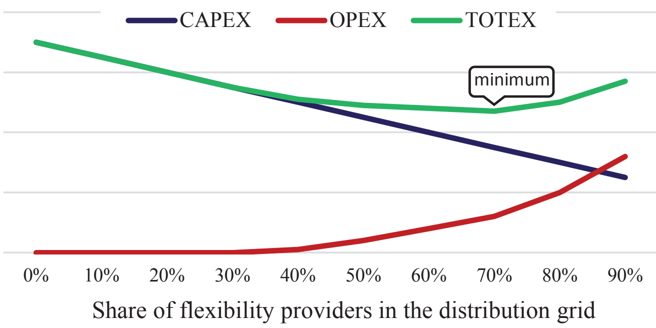

Fig. 9. Treatment of congestion management expenditures in regulatory scheme

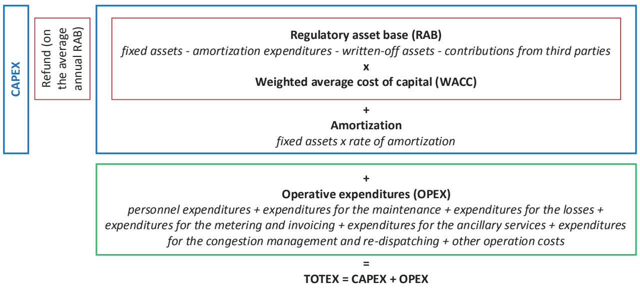

Fig. 10. Determination of the justifiable level of total expenditures - Croatian regulatory scheme for DSO [21]

Due to the complexity of the use of flexibility or any other innovation projects, Eurelectric recommends [22] to adopt the following approach in the implementation of the Clean Energy Package [14]:

- Member States may start testing market-based flexibility procurement with pilot projects. These pilot projects should test real use cases and consider different forms of procurement;
- If not already included in the regulation, regulators should allow regulatory sandboxes outside the current regulation framework to test those pilot projects. Given that it entails high technical and regulatory risks for the DSOs, the incurred costs stemming from these pilot activities for the DSOs shall be publicly disclosed, acknowledged and fully recoverable;
- In the event of already mature, economically and technically feasible solutions, to go straight to the deployment and implementation phase.

At the current stage of flexibility market development, market-based flexibility procurement might not provide the same systemic benefits in the long term as grid reinforcements do. Ideally, all stakeholders should strive towards market-based flexibility procurement mechanisms that provide at least comparable systemic and societal benefits as grid reinforcement.

IX. DSO Network Development Plans

Network development plans (10G plan) are an important tool to inform potentially interested parties where a demand of flexibility is or will be needed. In 10G plans the scenarios are fundamental to the result. They should at least cover a broad range of assumptions, including a scenario with the highest degree of probability, based on available information.

In the development plan, it is challenging to define the scope and breadth of how the DSOs should signal their medium- and long-term flexibility needs. In CEER's view [2], while providing information on foreseeable capacity issues and estimates of how much flexible capacity they might need in order to avoid grid expansion, DSO signaling could be very broad; i.e. covering characteristic grids, if not the entire distribution network. As a result, within the 10G plan the DSO would need and expect a certain number of MW of flexible assets within the ten-year horizon to be a viable solution within the defined area. If there are not enough flexible assets available currently or in the future, the DSO may need to make an investment decision at a given date upfront or potentially rely on other measures such as curtailment. Signaling the need goes beyond network development plans but this will be one way of doing it. The most important part is that network users and flexibility service providers (FSPs) know that the need is there in order for them to anticipate providing the flexibility, hence, seeing the opportunity for business and potential profits in the long run.

A significant component of how flexibility needs are signaled are the definitions of congested points or congested areas. A growing number of jurisdictions are taking an active role to require that operators make some amount of information about the grid available to developers or to the public. Information about available hosting capacity can be critical to evaluating the viability of a particular project. Figure 11 shows practice of the Netbeheer Nederland - the Dutch association of national and regional network operators. Starting from the December 2021, the Netbeheer Nederland provides congestion map (see [23]) for the high-voltage and medium-voltage grid, which shows which areas in the Netherlands are seeing increasing constraints for connection of demand and generation respectively.

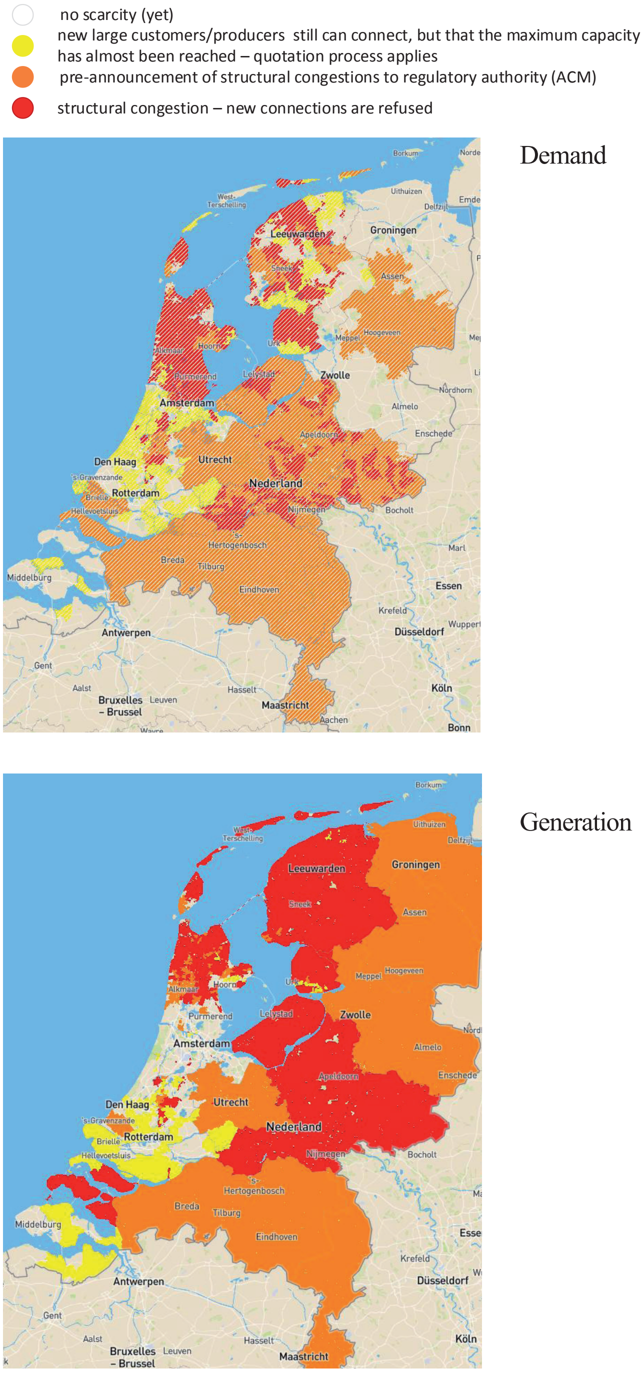

Fig. 11. Congestion map of the Netherlands [24] – state on December 22, 2022

When there is no scarcity in the observed area (transparent), new request for connection receives a quote with a limited validity period which cannot be extended (due to high interest to connect, operator wants to know whether and when new installation will

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actually be built).

When capacity of the grid in the observed area is limited (yellow), and the total requested capacity of requests exceeds the available hosting capacity in the observed area, adapted quotation process applies. Quotations are then valid for one month, instead of three months. For applications with a capacity equal to or smaller than 1750 kVA, the normal quotation process applies and also the existing agreements with current projects continue as usual.

When there is almost no (minimum) capacity available in the grid (orange), this is reported to the regulatory authority (ACM). The possibilities of congestion management are being analyzed. As long as the assessment is ongoing, operator does not know whether it can connect new request. Therefore, the connection request receives a provisional rejection. If the assessment shows that there is capacity for connection to the grid, operator issues a quote.

If the connection request exceeds the hosting capacity of the grid (red), even with the use of congestion management, then the quote will not be issued, and the request is placed on a waiting list. Even though there is no hosting capacity in the grid, request for quotation should be submitted because this way the operators know what the interest to connect is and also the investors will be informed as soon as there is free capacity in the grid. Have investor not paid the quotation 45 days after signing, the order and the connection capacity claim will lapse. All applications that are "rejected" (quote is not issued) are reported to the regulatory authority.

The Croatian Law on Electricity Market (Article 12, paragraph 7) obliges transmission and distribution system operators to review and make publicly available the information on the hosting capacity of the existing grid to safely and reliably integrate additional network users. Accordingly, on their website Croatian transmission system operator (HOPS) has recently published data which reflect the situation in 2022 (see [25]).

X. DSO Flexibility Procurement Components and Methods

DSOs should be able to identify relevant locations in their grids to engage in congestion management. Summarized, this includes determining where congestions are expected to occur, their cause, size, duration and time frame. Depending on the granularity, this information could be very sensitive and if made completely public could be to the detriment of the market functioning. The DSOs should consider the relative sensitivity, and thereby only to a limited extent publish their needs for flexibility, signaling it in as broad a way as possible, whilst still providing enough information to support the market.

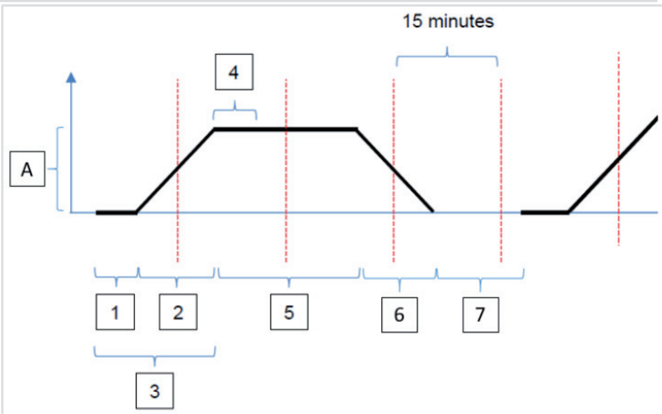
When a potential congestion has been identified, and the expected size and duration are forecasted, important assessments include selecting one or several resources to relieve the congestion, the method of activation and how the activation should be validated. Accordingly, an appropriate procurement procedure needs to take place. Within this frame of considerations there are various approaches to flexibility mechanisms that could reach an efficient outcome.

A vital part of DSOs signaling their needs, is establishing the product specification. In the Electricity Balancing Guideline (EBGL) [26] a list has been set up containing parameters that could be necessary to define a product, Figure 12. A description of all the attributes in such products and how they might look like in practice could be very comprehensive.

As observed by CEER [2], it is not a goal to parameterize everything, but in the long run, product specifications should primarily be set with reference to these key parameters. In the starting phase, through demonstrations and piloting, it might be a good idea to study and utilize the different characteristic of flexible resources, rather than defining specific products. As there is a vast variety of flexibility service providers characteristics, and in theory also DSO needs, it is important to be technology-neutral when setting up the specifications. In other words, defining them in an agnostic way to ensure a level playing field.

Characteristics of standard product for balancing capacity:

1. Balancing capacity validity period;
2. Minimum duration between the end of deactivation period and the following activation (or "minimum duration" in short;
3. Direction of the capacity: upward or downward.



Characteristics of standard product for balancing capacity bid:

1. Price characteristics;
2. Volume characteristics
(minimum bid quantity and granularity);
3. Bid divisibility;
4. Location;
5. Other as defined by TSO.

A – requested power;
1 – preparation time;
2 – ramping (up) period;
3 – full activation time;
4 – delivery period due to scheduled activation;
5 – delivery period;
6 – ramping (down) period;
7 – minimum duration between the end of deactivation period and the following activation

Fig. 12. Standard product characteristics for balancing capacity for frequency restoration reserves and replacement reserves, all TSOs' proposal (ENTSO-E) [27]

As an alternative to referring to the comprehensive list in the EBGL, CEER [2] proposes another way of addressing the designs of products; i.e. they mainly need to balance three considerations:

1. 1As specific as necessary to solve the congestion;
2. As broad as possible to facilitate liquidity; and
3. Standardized (on a national or regional level), e.g. it could be a similar approach as for balancing products.

Going back to the EBGL list, most of the parameters are related to time, availability and bid size. DSOs and FSPs should aim to experiment with the different attributes to see which of the considerations are most relevant in their specific use cases.

As a step further, the April 2019 TSO-DSO report [28] introduced the concept of a flexibility resource register. A flexibility resources register will allow system operators (TSO and DSO) to have visibility of which flexibility resources are connected to their grid and to their connected grids, so they know what resources they potentially have available when solving congestion. The objective of the flexibility resources register is to gather and share relevant information on potential sources of flexibility. The qualified connections would be registered in the flexibility resources register by the connecting system operator. This connection is visible to all relevant system operators. In this way, if a DSO or TSO has a congestion, they have visibility of all potential flexibility resources at all voltage levels. Several H2020 projects and national initiatives are now planning to look more into and develop some of the concepts of such a register. These outcomes should be taken into account in further design of the framework if they are deemed to be viable solutions to address or potentially implement at the national level.

The EU has put emphasis on active role of DSO and distribution grid and efficient TSO-DSO coordination to successfully accommodate high penetration of RES and achieve EU climate goals [3]. Cooperation and coordination between system operators in network planning phase in already business as usual (see [29]).

Flexibility can only be used efficiently if the right coordination mechanisms are put in place and the appropriate data and information are exchanged between DSOs, TSOs, customers and market players. As electricity flows are set to change significantly, without proper coordination mechanism, fixing a problem on the distribution level may cause additional problems on a transmission level and vice-versa. As observed in [4], all the TSO-DSO coordination mechanisms share similar prequalification, activation and settlement of flexibility resources, and in all mechanisms it is noticeable the evolution of the DSO role as it becomes more and more active participant. The review article [4] provides short overview of different TSO-DSO coordination mechanisms for procuring ancillary services in Europe.

Baselines are also a crucial aspect of flexibility procurement. In short, the offered flexibility for congestion management equals the deviation from a given baseline, Figure 13. Baseline methodologies are in most cases based on individual load profiles and historical data, although these are not legally binding at this point. In the establishment of baselines, it is important that all relevant actors are involved, preferably with regulatory overview, when categorizing and agreeing on the different terms of such a framework.

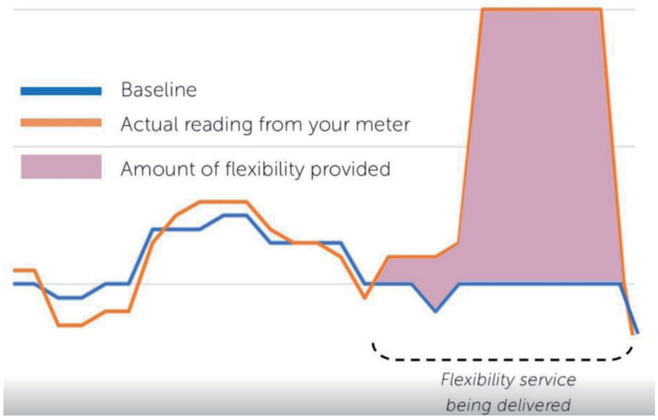


Fig. 13. Baseline - approach to measure the amount of flexibility delivered to the network operators

Article 32 of the Electricity Directive (2019/944) [3] clearly states that the preferred option for DSO procurement of service should be market-based. Based on a former consultation, in conclusion paper [9] CEER agreed with many respondents that market-based procurement is the preferred option because the procurement of flexibility on a competitive basis would be efficient as long as markets are liquid, overall costs are lower than in alternative solutions, DSOs comply with unbundling rules and market distortion/misuse potential is acceptable. In a market-based setting, the DSO could negotiate bilaterally or participate in an organized marketplace with network users offering their flexibility (producers, demand response, active customers), or interact with service providers acting on their behalf (aggregators). Essential parts of a well-functioning market with free competition are:

- Full information;
- Rational actors;
- Standardized products;
- Liquidity;
- Low entry and exit costs; and
- Low transaction costs.

However, it should be noted that Article 32 provides also for a situation where the market is restricted under certain conditions, stating that flexibility procurement has to be economically efficient and must not lead to severe market distortions or to higher congestion. Therefore, DSOs and regulatory authorities should carefully assess which model (see Figure 2) is appropriate in which context and what the impact of the combination of several categories can be. In other words, when evaluating the categories, the type of congestion to solve shall be considered, taking into account that a combination of the categories could be beneficial.

The DSO's access to market-based procurement of flexibility is a new phenomenon, thus there is a lack of empirical data and experiences in this context (see Eurelectric [22] recommendation in paragraph 8). At this point, there are numerous pilots and demonstration projects being undertaken to get deeper insights into the subject and to explore the benefits of this access: [4,7,8,30]. These are mostly still in the starting phase and the scope of the projects seems to vary significantly. However, on the other end of the spectrum is the UK, where all DSOs are tendering for flexibility as business as usual, inviting bids according to a (predefined) specification of needs (see [31]).

XI. Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) is the collective term to describe the whole infrastructure from smart meter to two way-communication network to control center equipment and all the applications that enable the gathering and transfer of energy usage information in near real-time. AMI makes two-way communications with customers possible and is the backbone of smart grid. The objectives of AMI can be remote meter reading for data, network problem identification, load profiling, energy audit and partial load curtailment in place of load shedding. Smart grids and advanced metering systems are key enablers of flexibility. The advent and wider adoption of smart home technology and smart metering systems will further the possibilities regarding demand response; this in turn will help consumers to be more price-responsive and will increase the value of implicit flexibility.

According to the Croatian Law on Electricity Market [1], the minister responsible for energy is obliged to make decision on the introduction of an AMI in the Republic of Croatia based on an economic assessment of all long-term costs and benefits of such a system prepared by the regulatory authority (HERA). The input data for the economic assessment, including main features of the proposed AMI and the time frame for its introduction shall be provided by the DSO.

Regardless that the minister has not made an official decision on national plan for smart meters roll-out, there is certain action concerning smart metering installation taking place in Croatia.

Around 50% of total low voltage (LV) commercial customers metering points (Figure 14) and 13% of total households metering points (Figure 14) have been equipped with smart meters. More precisely, all connection points of medium voltage (MV) and LV commercial customers >22 kW have been equipped with smart meters and remote reading. 36% of LV single tariff and 44% of LV dual tariff commercial customers already have smart meters, as well as 45% of public lighting connection points. Summarized, at the end of 2021 17% penetration rate of smart meters was achieved in Croatia.

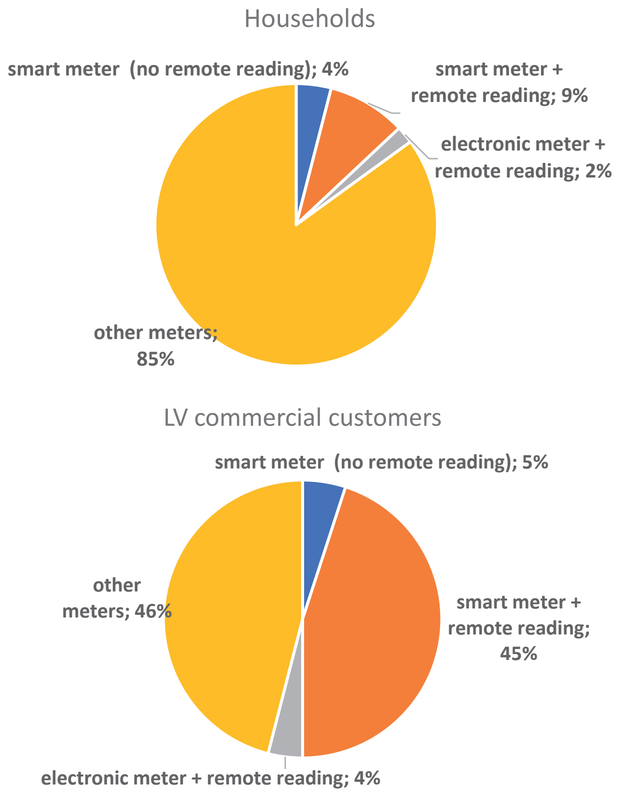


Fig. 14. Types of electricity meters at LV customers - Croatia, end of 2021 [32]

For flexibility to be traded and responsibility for imbalances to be accounted for, we need means for verifying that the flexibility took place, and a its volume. Two elements of measurement are necessary for the other regulatory aspects to work:

a) A 'baseline' of consumption for a flexible resource had flexibility not been delivered. That is, a mathematical model or an estimate of how much energy the resource would have used in the absence of an action (see section 10);

b) A measurement of real-time usage of the flexible resource, as distinct from the rest of a customer's load.

Flexibility delivered is therefore simply the difference between the baseline and the metered real usage of the flexible resource.

To distinguishing the real-time usage of the flexible resource there are two options:

a) Sub-metered model: two (or more) separate metered data variables, one for the customer's normal consumption and one for the new flexible unit(s),

b) Single-meter model: use one data variable for the whole customer's consumption, and then use a mathematical model to split this data between load and flexibility delivered. This is what we have today in practice, where there is only one consumption input submitted by the DSO-owned smart-meter.

Flexibility service providers have the option to use either flexibility asset sub-meters or metering data from the connection meters of network operators [33].

The consumption of flexible resource in most instances is metered by the service provider (aggregator). If a service provider wants the ability to control (or just observe) the consumption of the flexibility resource or check that the consumer is doing what they said, then the consumption on the flexible resource needs to be metered. What this means in practice is that the sub-meters required for offering and metering the consumption of a specific flexible unit should be installed and paid by the service provider.

XII. Conclusion

The main aim of DSOs and regulatory authorities is to maximize the efficiency of the distribution network, by utilizing the existing and future infrastructure to its full capacity. Constraint management consists of several methods to handle challenging grid situations. As a starting point, DSOs can manage constraint issues with the activation of their own flexible grid assets. Such actions are a default option and applied before or at the same time as considering other options. If a DSO cannot solve a problem with its own assets (e.g. topology changes, tap changers, voltage boosters, etc.) it may need to invest in new assets (grid reinforcement); the procurement and use of flexibility for constraint management could be the better solution economically. The use of flexibility to maximize the efficiency of the grid could provide socio-economic benefits by utilizing existing resources that could decrease or defer the need for new investments in grid infrastructure.

With regard to the procurement of flexibility services DSOs should be able to identify relevant locations in their grids to engage in congestion management. This includes determining where congestions are expected to occur, their cause, size, duration and time frame. Flexibility mechanisms are divided into implicit (actors respond to fixed price signal) and explicit (actors themselves bid in their price and actively contribute to the price formation). The Croatian Law [1] recognizes the four different mechanisms for DSO's access to flexibility: Rule based approach, Connection agreements, Network tariffs, and Market based procurement.

Network tariffs can be designed to provide incentives to system users to change their behavior in such a way that it benefits efficient distribution system operations by the DSO. However, the actual impact of a particular tariff structure on actual behavior of system users inherently has a degree of uncertainty regarding its actual impact because system users may show different behavior than expected or may not be able to shift or reduce their demand. Dynamic network tariffs and flexibility procurement differ in that under the procurement of flexibility, the DSO explicitly contracts for it with the customer or their intermediary, while with dynamic tariffs, the flexibility provided by customers is implicit. Thus, the effectiveness of the latter firstly depends on the actual existence of customer flexibility and, secondly, on the interaction between the network tariff signals and other behavior-influencing factors. Realizing the benefits of dynamic network tariffs is more complex when explicit flexibility is applied, because the interaction between both instruments makes the effects of any behavior change in response to tariffs harder to predict. Under a system of continuously changing tariffs and network load situations, it will be very difficult to effectively allocate and (subsequently) apply explicit flexibility. Therefore, the combination of static network tariffs and procured explicit flexibility might be the most reliable way to reduce network costs.

When planning, expanding and managing their networks DSO may either opt for the use of greater network expansion (CAPEX) with less need of flexibility or less network expansion with a greater need of flexibility (OPEX). The details of the regulation and the lawmakers' provision to necessary grid expansions, including potential degrees of freedom for the DSO on network dimensioning, determine the direction of the system operator's approach. If a DSO decides to design the network with scarce capacity, meaning lower capacity margins, there is a greater need to carry out congestion management procedures.

Due to the complexity of the use of flexibility or any other innovation projects, pilot projects should test real use cases and consider different forms of flexibility procurement. Regulatory authority should allow regulatory sandboxes outside the current regulation framework to test those pilot projects. Given that it entails high technical and regulatory risks for the DSOs, the incurred costs stemming from these pilot activities for the DSOs shall be publicly disclosed, acknowledged and fully recoverable.

Network development plans (10G plan) are an important tool to inform potentially interested parties where a demand of flexibility is or will be needed. In 10G plans the scenarios are fundamental to the result. They should at least cover a broad range of assumptions, including a scenario with the highest degree of probability, based on available information. As a result, within the 10G plan the DSO would need and expect a certain number of MW of flexible assets within the observed horizon to be a viable solution within the defined area. Signaling the need goes beyond network development plans but this will be one way of doing it. The most important part is that network users and flexibility service providers know that the need is there in order for them to anticipate providing the flexibility, hence, seeing the opportunity for business and potential profits in the long run.

When a potential congestion has been identified, and the expected size and duration are forecasted, important assessments include selecting one or several resources to relieve the congestion, the method of activation and how the activation should be validated. Accordingly, an appropriate procurement procedure needs to take place. Within this frame of considerations there are various approaches to flexibility mechanisms that could reach an efficient outcome. A vital part of DSOs signaling their needs, is establishing the product specification. Crucial aspect of flexibility procurement is also baseline - approach to measure the amount of flexibility delivered.

This paper proposes the process of DSO request to own, develop, manage or operate energy storage facilities, and DSO access to flexibility, in accordance with the Article 79 and Article 75 of the Croatian Law on Electricity Market [1] respectively.

It is worth considering the possible additional role of the Croatian Power Exchange (CROPEX) as a local electricity flexibility market platform in Croatia.

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Calculation of Lightning and Switching Overvoltages Transferred through Power Transformer

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***Abstract* — During their lifespan all primary HV equipment installed in the power system is subjected to transients. Therefore, it is necessary to adequately dimension and protect the equipment. However, in the networks with high share of renewables, power electronics, cables or near gas insulated substation (GIS), the failure can occur even though good practices of insulation coordination are fulfilled.**

In this paper, a high-frequency power transformer model is presented. Such model is based on measurements of admittance matrix and is adequate for simulation of fast front transients in EMTP like software. Additionally, simulations of transferred lightning and switching overvoltages are given for the observed power transformer unit.

***Keywords* — fast front transients, power transformer, EMTP, measurement, admittance matrix**

I. Introduction

In everyday operation, power transformers are exposed to switching and lightning overvoltages. Overvoltages that are experienced by the transformer and other HV equipment inside substation can be estimated and calculated using advanced simulations in software tools for calculating transient phenomena, for example ElectroMagnetic Transients Program (EMTP) [1]. Such simulations imply the use of advanced high-frequency transformer models and frequency-dependent models of other HV equipment in the substation.

Advanced transformer models are necessary to simulate fast and very fast overvoltages in the power system [2], [3]. Due to the significant share of high frequencies in such overvoltages, resonant phenomena may occur within the windings of the power transformer, which can endanger its dielectric insultation. For this reason, on-line monitoring systems for measurement of overvoltages can be installed and usually they are connected over measuring tap of transformer bushing [4], [5]. The electromagnetic behaviour of the transformer at its terminals is a function of these resonant phenomena. Consequently, traditional transformer models, made primarily for the nominal operating frequency (50 Hz or 60 Hz), are not accurate enough to simulate such transient phenomena [6].

According to CIGRE research [7], the majority of power transformer failures have an unknown cause. Therefore, it is necessary to pay particular attention when protecting such an object, because standard transformer tests do not cover all phenomena and conditions in which the transformer can be found in the network. Particularly noteworthy are resonant overvoltages, where transformer protection with surge arresters is not effective. Examples of faults, caused by the interaction of the transformer and electric power network, are given in the CIGRE brochure [8].

In this paper, a high-frequency power transformer model is presented. The second chapter describes a method for measuring the frequency-dependent admittance matrix of the transformer. The third chapter explains the transformer model developed in the software tool for the calculation of transient phenomena. Verification of the model using the measurement results in the time domain is described in the fourth chapter. Examples for the calculations of possible transient phenomena due to lightning strikes or switching operations are given for the considered power transformer in the fifth chapter. Conclusions are given in the chapter six.

II. Method for Measuring the Frequency-dependent Admittance Matrix of the Transformer by Measuring the Voltage Ratios

Below is a procedure for measuring the admittance matrix using the capabilities of the Vector Network Analyzer (VNA) device to measure the ratio of input and output voltage. Such a device corresponds to the Sweep Frequency Response Analysis (SFRA) device, which is a part of the standard measurement equipment in every high-voltage laboratory. This kind of measurement can also be carried out in the field, in the transformer substation.

The procedure for measuring the transformer admittance matrix with the VNA device is based on the following expressions [9] -[11]:

$$H_{voltage}(s) = \frac{V_{out}(s)}{V_{in}(s)} \tag{1}$$

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https://doi.org/10.37798/2022711376

$$\begin{pmatrix} I_1 \\ I_2 \\ \vdots \\ I_{N-1} \\ I_N \end{pmatrix} = \begin{pmatrix} Y_{11} & \cdots & Y_{1N} \\ \vdots & \ddots & \vdots \\ Y_{N1} & \cdots & Y_{NN} \end{pmatrix} \cdot \begin{pmatrix} V_1 \\ V_2 \\ \vdots \\ V_{N-1} \\ V_N \end{pmatrix}, \qquad (2)$$

,

where:

$H_{voltage}$ is ratio of measured input voltage V_{in} and output voltage V_{out}.

The circuit for measuring the admittance matrix differs for diagonal and off-diagonal coefficients of the matrix. Two measurement circuits are shown in the figures below considering a 300 MVA YNa0d5 autotransformer as a test object, which has 10 or 11 terminals, depending on whether the tertiary winding is short- or open-circuited.

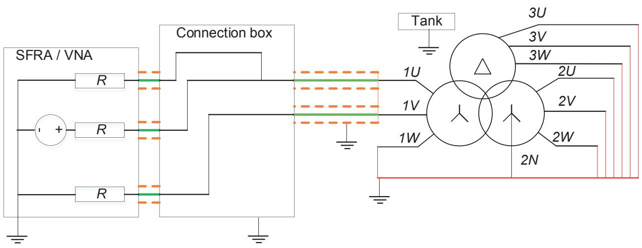


Fig. 1: Circuit for measuring off-diagonal coefficients of the admittance matrix.

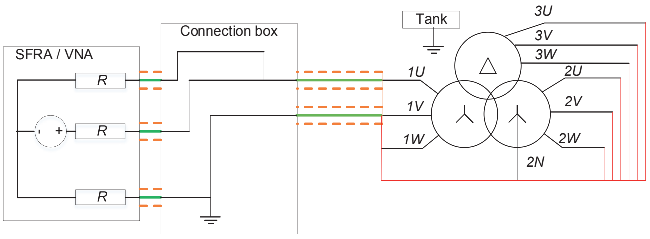


Fig. 2: Circuit for measuring diagonal coefficients of the admittance matrix.

Figures 1 and 2 show the equivalent scheme of the measuring equipment, which consists of three terminals: source, reference terminal and response measurement terminal. Each of the terminals is terminated with an impedance of 50 Ω, so that there are no reflections between the connected measuring cables (coaxial cable with a characteristic impedance of 50 Ω) and measuring device. The measuring device is set to measure the voltage ratio between the response measuring terminal and the reference terminal.

In all measurements it is necessary to maintain the grounding of the transformer tank.

Since the measurements are made in a high-voltage laboratory, the connection box is used only for grounding the coaxial cable shield. In the field, the connection box is used for easier handling and reconnection during measurement. Due to the limited possibilities and the unavailability of the bushing top, such a box drastically reduces the duration of the measurement. Such a box is not required for measurements in the laboratory, which reduces the number of cables used and thus increases the accuracy of the measurement.

In the figures above, the coaxial cables are marked in green while their electromagnetic shields are marked in orange. Copper strips used for the connection to the transformer cover are shown in red. The connection between the measuring device and the connection box is made using short coaxial cables, while the connection between the connection box and the top of the transformer bushing is made using 18 meter long coaxial cables, which are part of the standard SFRA equipment.

Figure 1 shows the measurement of the admittance matrix element Y_{12} (between the terminals 1U-1V). All transformer terminals not involved in the measurement are short-circuited and grounded. In this way, from the expression for the admittance matrix (2) the following expression is obtained:

$$Y_{ij}(s) = -\frac{V_i(s)}{V_j(s)} \cdot \left(Y_{ii}(s) + \frac{1}{R}\right) \qquad (3)$$

When measuring off-diagonal coefficients of the admittance matrix, all electromagnetic shields of the coaxial cables are short-circuited and grounded using wide copper strips at one end and a grounded aluminium connection box at the other end.

It is evident from expression (3) that each off-diagonal coefficient depends on the corresponding diagonal coefficient of the admittance matrix. In order to obtain admittance by measuring the voltage ratios, it is necessary to use the internal resistance of the response measurement terminal as a shunt resistor to measure the current. In this case, the diagonal coefficient of the admittance matrix can be calculated as:

$$Y_{ii}(s) = \frac{I_i(s)}{\left(V_{in}(s) - V_{out}(s)\right)} = \frac{V_{out}(s)}{R \cdot \left(V_i(s) - V_{out}(s)\right)} \qquad (4)$$

From figure 2 it can be seen that the measurement circuit is grounded before the measuring device so the current that closes through the transformer tank towards the measuring device contributes to the voltage drop on the internal resistance of the response measurement terminal. By doing this, all the sheaths of the coaxial cables must be short-circuited and left at the floating potential, so that the voltage drop across the internal resistance of the response measurement terminal is not equal to 0 V.

III. Transformer Model in EMTP

The transformer model was created in the software for calculation of transients EMTP, using the semi definite programming (SDP) method for rational approximation, i.e. mathematical description of the model [12]. The frequency-dependent admittance matrix is described by rational functions with 60 poles. To exclude the noise from the measurements, an average filter (with a factor of 5) was used. Models have 10 terminals (1U, 1V, 1W, 2U, 2V, 2W, 2N, 3U, 3V, 3W). The results of the success of the mathematical model using rational functions are presented in the figures below. The deviation shown in the figures has been calculated as the amplitude difference between the measurement and the mathematical description of each coefficient.

The cumulative relative error of the mathematical description calculated using expression (5) is about 5%, which is consistent with the literature [12].

$$RMSRE = \sqrt{\frac{\sum_{i=1}^{N}\sum_{j=1}^{N}\sum_{k=1}^{N_k}\left(\left|\frac{Y_{ij}(f_k)-Y_{ij,fit}(f_k)}{Y_{ij}(f_k)}\right|^2\right)}{N^2 * N_k}}, \qquad (5)$$

,

where:

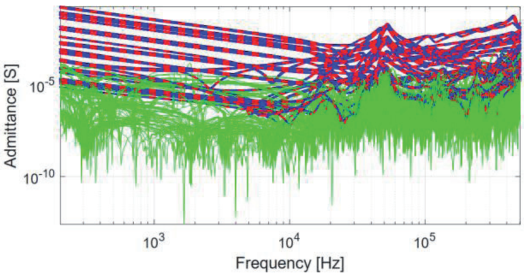
N = number of transformer terminals,

f_k = frequency at which admittance matrix elements where measured,

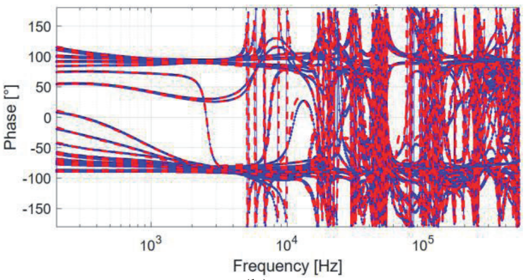
N_k = number of frequency points,

Y_{ij} = measured transformer admittance matrix coefficient,

$Y_{ij,fit}$ = mathematical description of transformer admittance matrix coefficient.



(a)



(b)

Fig. 3. Results of the rational approximation of the admittance matrix measured at nominal tap position (measured curves are marked in blue, the mathematical model in red, and the difference in green).

IV. Verification of the 300 MVA Transformer Model

This chapter presents a comparison of the results obtained by calculation of transients in the time domain and the results of the measured transferred overvoltages. The calculations are performed using EMTP, while the measurements are performed in the HV laboratory to minimize the influence of the environment and grounding as much as possible.

The measurements performed in this paper and are shown in the table 1. Standard (1.2/50 μs) lightning impulse (LI) is applied at terminal 1U in configuration 1, and at terminal 1V in configuration 2.

Transferred lightning overvoltage measurements are carried out for different combinations of *R*, *L* and *C* elements connected to the primary/secondary of the transformer, in order to verify the transformer models in the time domain and their behaviour when we consider a certain capacitance, inductance and resistance connected to the primary/secondary of the transformer, or when it is left open circuit (worst case for transferred overvoltages).

Table I.

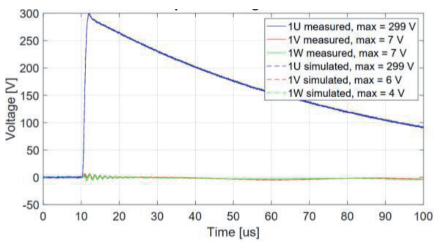
Measurement configuration for transferred overvoltages

Configuration	1U	1V	1W	N	2U	2V	2W	3U	3V	3W
1	LI	R	R	grounded	isolated	isolated	isolated	isolated	isolated	isolated
2	R	LI	R	grounded	R	R	R	C	C	C

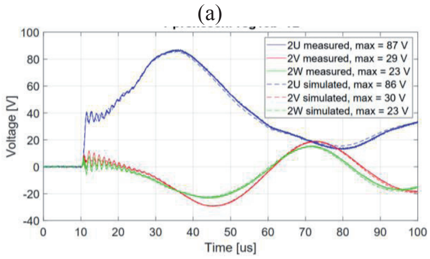
During the measurement, the voltages at all terminals of the transformer are observed. In table 1, *R* presents the characteristic impedance of the overhead transmission line (400 Ω), while C indicates the capacitance of the power cable (C ≈ 0.47 μF).

The figures below provide comparisons of the transformer model response and the measurement results.

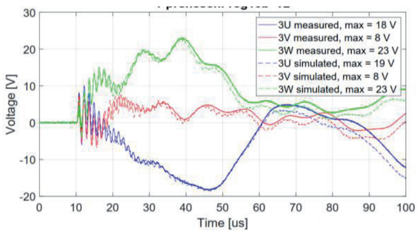
The model was also verified at the nominal frequency of 50 Hz. The voltage waveforms as well as the voltage phasor display of the model are shown in the figure below.



(a)

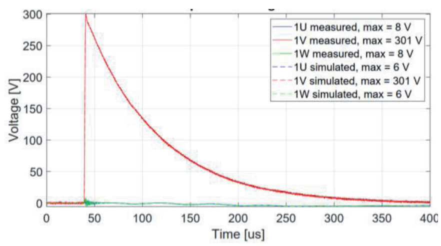


(b)

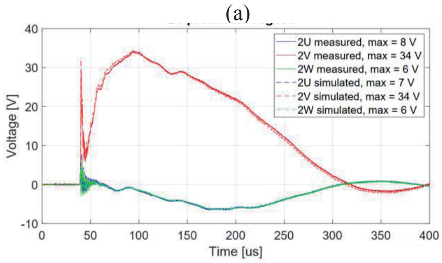


(c)

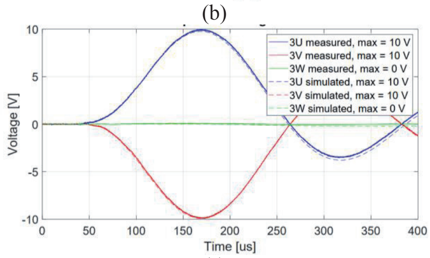
Fig. 4. Measurement results of transmitted overvoltages for configuration 1, at nominal tap position



(a)



(b)



(c)

Fig. 5. Measurement results of transmitted overvoltages for configuration 2, nominal tap position

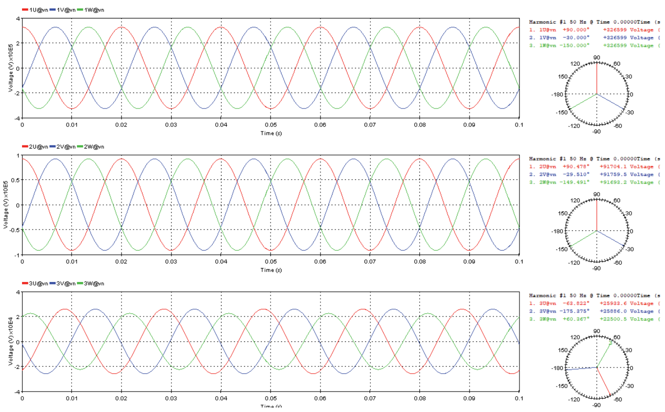


Fig. 6. Response model at 50 Hz, for nominal tap position

Values are additionally compared in table 2.

Table II.

Comparison of nominal and calculated voltages at 50 Hz for nominal tap position.

Winding	Phase	Nominal [kV]	Model [kV]	Rel. error [%]
Primary	a	220	220.0	-
	b	220	220.0	-
	c	220	220.0	-
Secondary	a	115	111.6	2.97
	b	115	111.6	2.96
	c	115	111.9	2.73
Tertiary	a	30	31.76	5.87
	b	30	31.70	5.68
	c	30	27.56	8.14

Increased relative error at tertiary side is caused by relatively low signal-to-noise ratio. Additionally, tertiary winding is delta connected and performing frequency response measurements is relatively demanding in the considered case. Even though the developed model is intended for high frequencies, relatively good results are also obtained for the operating frequency of 50 Hz.

V. Simulations of Transferred Lightning and Switching Overvoltages

Lightning overvoltages are calculated in the case of a lightning strike at 400 kV transmission line in the vicinity of an air-insulated substation where a 400/110/30 kV, 300 MVA, power transformer is installed. Detailed high-frequency models of transformer substation and connected transmission lines are developed in EMTP. Equivalent scheme of air-insulated substation considering reduced topology for calculations of transferred lightning overvoltages with indicated positions of surge arresters is shown in Fig. 7.

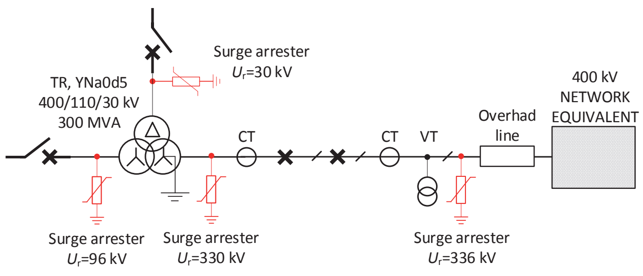


Fig. 7. Equivalent scheme of air-insulated substation considering reduced topology for calculations of transferred lightning overvoltages with indicated positions of surge arresters.

Calculations are made with previously described high-frequency model of power transformer, which is created based on the frequency-dependent admittance matrix measurements. Transferred overvoltages are calculated at secondary and tertiary side of power transformer. An analysis of the effectiveness of the overvoltage protection is carried out and the resonant overvoltage phenomena are checked. Overvoltage calculation is based on the following conservative assumptions, according to which calculated values of lightning overvoltages should be higher than the ones that may occur in the reality:

- Substation operates with reduced topology – there are only one 400 kV transmission line bay and one transformer bay in operation. In this reduced topology, the overvoltage wave propagates directly towards the transformer, while in full topology it is distributed to the neighbouring 400 kV bays. Therefore, it is expected that with all the lines connected, the overvoltage amplitudes in the transformer bay will be lower.
- An extremely rare case of a 250 kA lightning strike at the second tower of the 400 kV transmission line from the entrance to the transformer substation is assumed, with tower grounding resistance of 10 Ω. In the second case, a direct 40 kA strike to the phase conductor is simulated. This "critical" current is obtained from electro-geometric model of the overhead line, and it represents the highest amplitude of the lighting strike that can hit the phase conductor directly. Lightning strikes with higher currents cannot directly hit the phase conductors due to the protection provided by the shield wires.
- At the moment of lightning strike, a state of increased operating voltage (420 kV) is assumed, which increases the probability of a backflashover occurrence.
- At the moment of lightning strike to 400 kV transmission line, 110 kV and 30 kV sides of power transformer are unloaded (open circuit breaker from 110 kV and 30 kV side). In this case, overvoltages that are transmitted to the secondary and tertiary transformer windings, and they are reflected on open contacts of circuit breaker. Reflected overvoltages travel back towards the transformer, so increased values of overvoltage can be expected in this case. The primary, secondary and tertiary sides of the transformer are protected by surge arresters (rated voltage of the surge arresters: U_r=330 kV, U_r=96 kV, U_r=38 kV).

A lightning strike causes a flashover in phase C, making it the phase in which the highest overvoltage is reached at the 400 kV transformer winding. Surge arresters in the 400 kV transformer bay limit the overvoltage to 836.6 kV. The calculated overvoltage waveforms are shown in figures 8-12. Figure 14 shows the measurement results of the magnitude and phase angle of admittance for 30 kV winding (phase B-C) as a function of frequency. The resonant frequencies of the 30 kV windings can be observed (approximately at the frequency of 52 kHz and 1,6 MHz) which differ from the dominant frequencies of the overvoltage oscillations (6.8 kHz), therefore it can be concluded that there is no risk of resonant overvoltages in 30 kV transformer windings (Fig. 13).

Bruno Jurišić, Tomislav Župan, Mario Jurić, Božidar Filipović-Grčić, Katarina Musulin, Calculation of Lightning and Switching Overvoltages Transferred through Power Transformer, Journal of Energy, vol. 71 Number 1 (2022), 18–26
https://doi.org/10.37798/2022711376

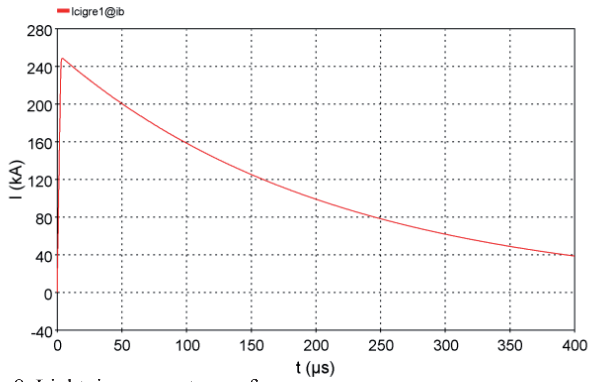


Fig. 8. Lightning current waveform.

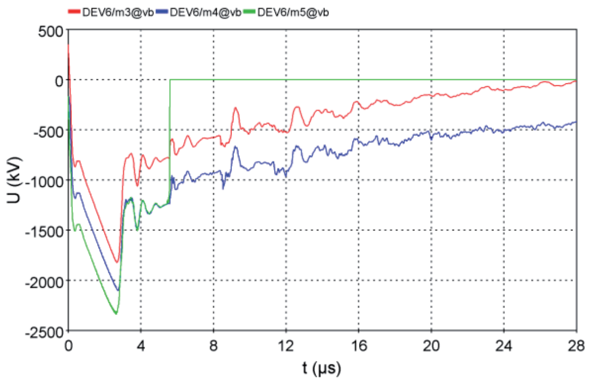


Fig. 9. Flashover in phase C across the insulator string on tower struck by lightning.

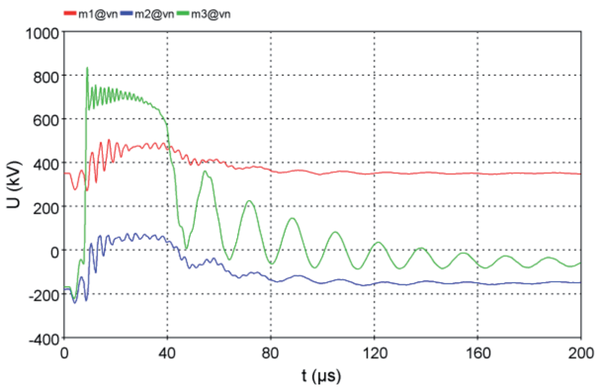


Fig. 10. Overvoltages on the 400 kV side of the transformer (U_{max}=836.6 kV).

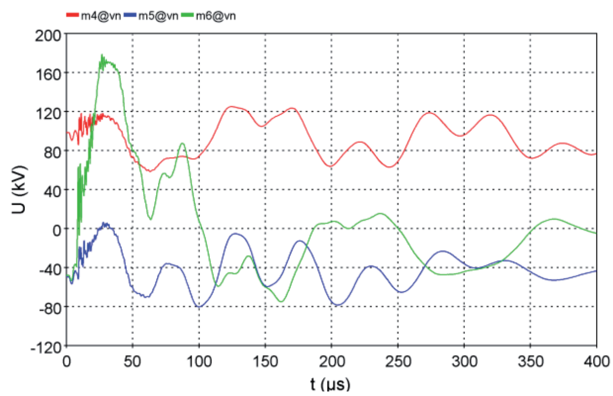


Fig. 11. Transferred overvoltages on the 110 kV side of transformer (U_{max}=178.7 kV).

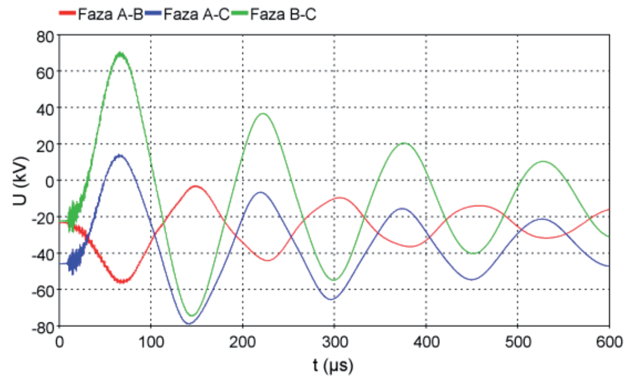


Fig. 12. Transferred line overvoltages on 30 kV side of transformer (U_{max}=79.13 kV).

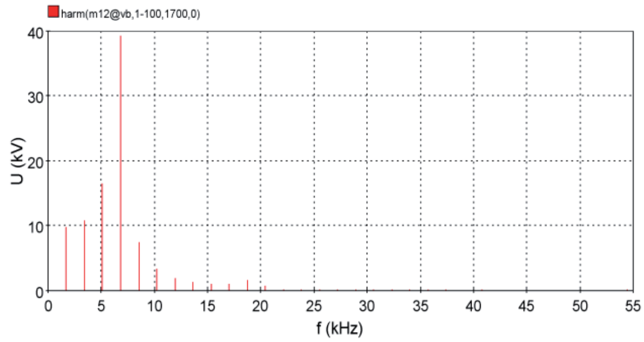


Fig. 13. Frequency spectrum of lightning overvoltage (phase B-C).

An overview of the calculation results is shown in the following table.

TABLE III.

OVERVIEW OF THE CALCULATION RESULTS OF LIGHTNING OVERVOLTAGES

	Lightning strike to the top of the tower	Lightning strike to the phase conductor
Lightning current amplitude	250 kA	40 kA
Overvoltages at the 400 kV side of the transformer	836.6 kV	838.2 kV
Transferred overvoltages on the 110 kV side of the transformer	178.7 kV	154.12 kV
Overvoltages on the open contact of the 110 kV circuit breaker	191.6 kV	196.9 kV
Transferred phase overvoltages on the 30 kV side of the transformer	48.17 kV	32.15 kV
Transferred line overvoltages on the 30 kV side of the transformer	79.13 kV	48.9 kV
Current through surge arresters in 400 kV overhead line bay	3.27 kA	13.8 kA
Surge arrester energy in 400 kV overhead line bay	18.62 kJ	9.15 kJ
Current through surge arresters in a 400 kV transformer bay	5. 05 kA	6.06 kA
Surge arrester energy in 400 kV transformer bay	69.9 kJ	6.6 kJ
Surge arrester energy in 110 kV transformer bay	96.5 J	0.87 kJ

Lightning overvoltage amplitudes for all elements of substation are within the permitted limits and they do not exceed the standard rated lightning impulse (1,2/50 μs) withstand voltages 1425 kV, 550 kV and 170 kV, which correspond to highest voltage for

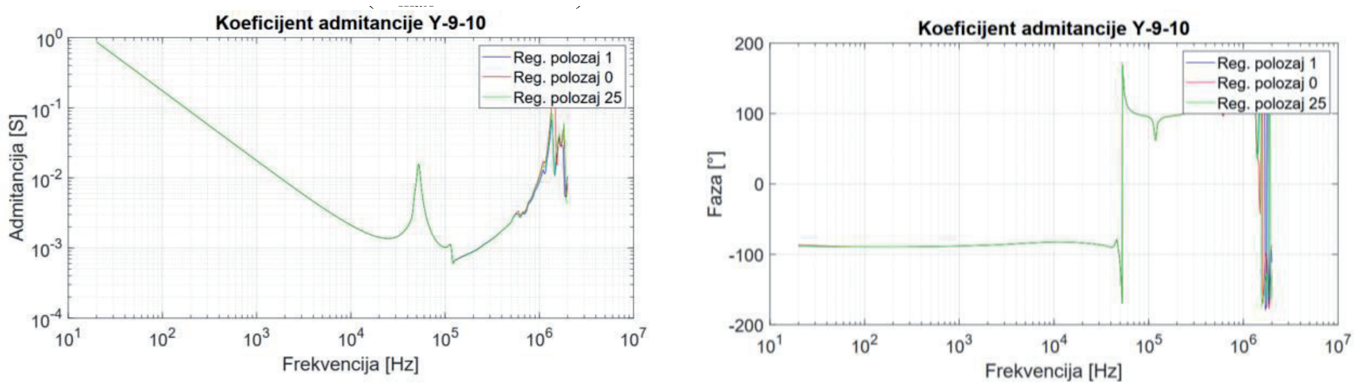


Fig. 14. Measurement results of a) amplitude and b) phase of the admittance of 30 kV winding (phase B-C).

equipment 400 kV 110 kV and 30 kV, respectively. Analysis of the frequency spectrum of the overvoltage and the frequency response of the transformer windings show that in the analysed cases there is no possibility of resonant overvoltages in the transformer winding. The energy stress of the surge arresters is within permitted limits. It is recommended to select the characteristics of the surge arresters in the line bay (U_r=336 kV) so that they correspond to the characteristics of the arresters in the transformer bay (U_r=330 kV). This would ensure better protection of equipment against overvoltages (mainly in the line bay) and the total energy stress would be distributed more evenly between surge arresters in the line bay and the transformer bay.

Transient phenomena during the switching of the vacuum circuit breakers in a 30 kV substation are analysed. Substation is connected on one side to a 400/110/30 kV power transformer via a 40 m long 30 kV cable and on the other side with a 200 m long 30 kV cable to a neighbouring 30 kV substation. In the neighbouring substation, there is a 30/0,4 kV distribution transformer with rated power of 1250 kVA. A detailed model of the 30 kV vacuum circuit breaker is developed in the EMTP for calculation of transient phenomena. Equivalent scheme of substation considering switching of vacuum circuit breaker in 30 kV network with indicated positions of surge arresters is shown in Fig. 15.

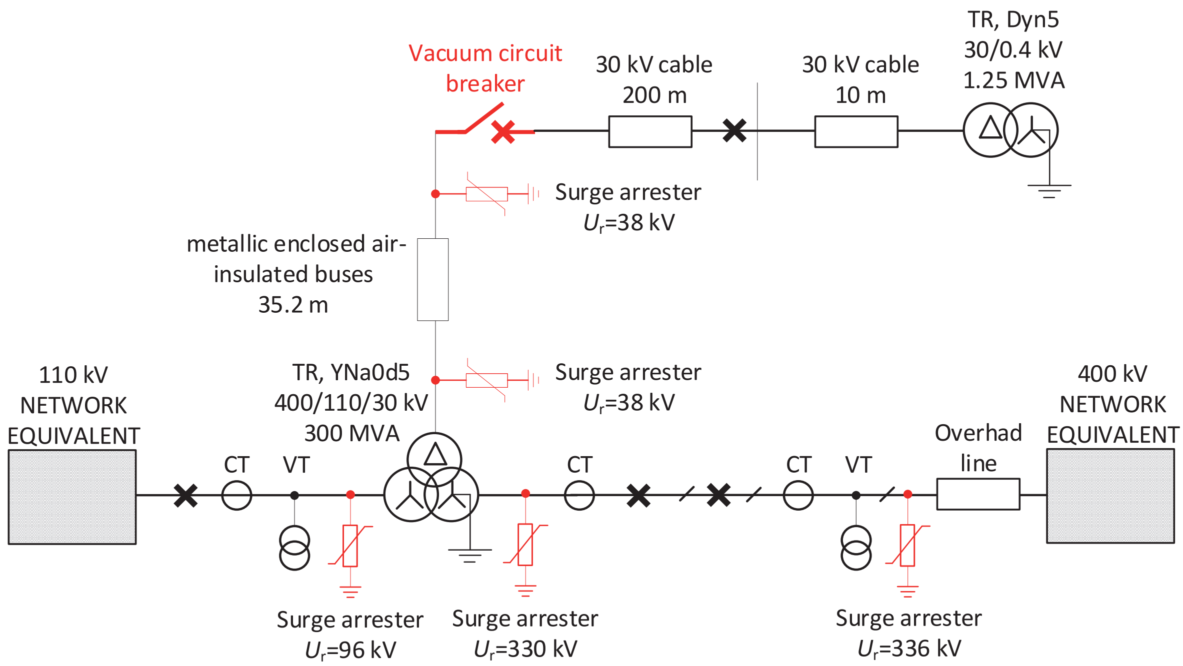


Fig. 15. Equivalent scheme of substation considering switching of vacuum circuit breaker in 30 kV network with indicated positions of surge arresters.

The model enables the simulation of restrikes that occur during the switching off a vacuum circuit breaker. Surge arresters (U_r=38 kV) are installed on the 30 kV side of the 400/110/30 kV power transformer and at the entrance of the cable to the 30 kV substation, where vacuum circuit breakers and other equipment are located. Two cases are analysed:

- Case A): switching off 200 m long cable to the neighbouring 30 kV substation and an additional 10 m cable to 30/0,4 kV distribution transformer that is loaded with the nominal load.
- Case B): energization of the 200 m cable to the neighbouring 30 kV substation.

Table IV.

Overview of the calculation results – switching off the vacuum circuit breaker (case A)

Chopping current	Overvoltages at the end of a 200 m long 30 kV cable and at the distribution transformer	Transient recovery voltage on the vacuum circuit breaker	Frequency analysis of overvoltage on the transformer tertiary winding
15 A	U_{maxA}=77.85 kV U_{maxB}=50.64 kV U_{maxC}=88.75 kV	U_{maxA}=61.53 kV U_{maxB}=50.63 kV U_{maxC}=50.38 kV	HF spectrum of overvoltage: dominant frequency 566 kHz; LF overvoltage spectrum: dominant frequency 6.2 kHz

Figures 16-21 show the waveforms of the calculated overvoltages for case A. From the results it can be concluded that there is no risk of resonant overvoltages on the tertiary winding of the transformer due to the switching of vacuum circuit breaker.

Table V.

Overview of the calculation results – switching on the vacuum circuit breaker (case B)

Inrush currents amplitudes	Switching overvoltages at the beginning and at the end of a 200 m long 30 kV cable	Frequency analysis of overvoltage on the transformer tertiary winding
I_{maxA}=581.4 A I_{maxB}=646.3 A I_{maxC}=582.9 A	Beginning: U_{maxA}=28.2 kV, U_{maxB}=28.7 kV, U_{maxC}=25.5 kV; End: U_{maxA}=46.8 kV, U_{maxB}=51.5 kV, U_{maxC}=46.3 kV	HF spectrum of overvoltage: dominant frequencies 784 kHz, 513 kHz and 1.145 MHz; LF overvoltage spectrum: dominant frequency 6 kHz

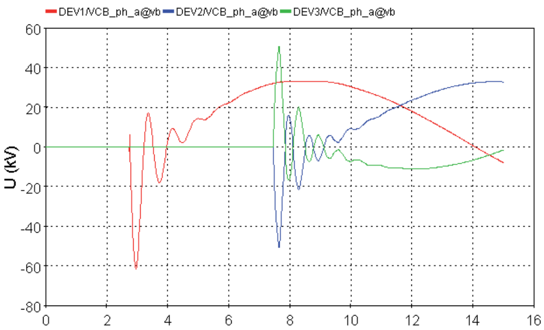


Fig. 16. Transient recovery voltage on the vacuum circuit breaker.

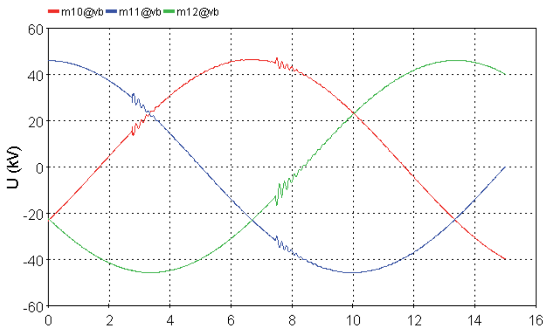


Fig. 17. Line voltages on the power transformer tertiary.

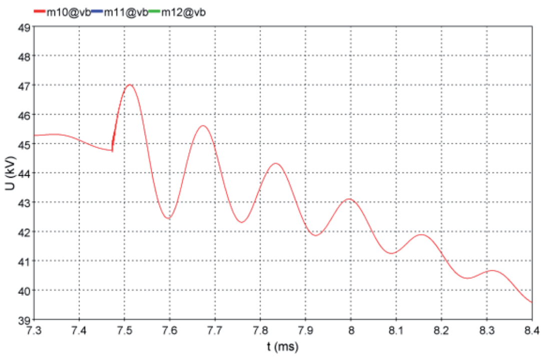


Fig. 18. Detail of overvoltage on the tertiary winding - dominant frequency after current breaking is approximately 6,2 kHz.

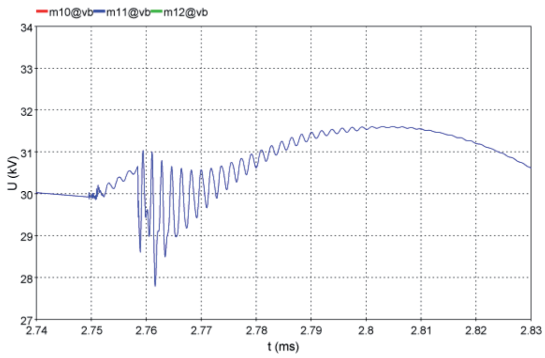


Fig. 19. Detail of overvoltage on the tertiary winding - dominant frequency before current breaking during the transient recovery voltage is 566 kHz

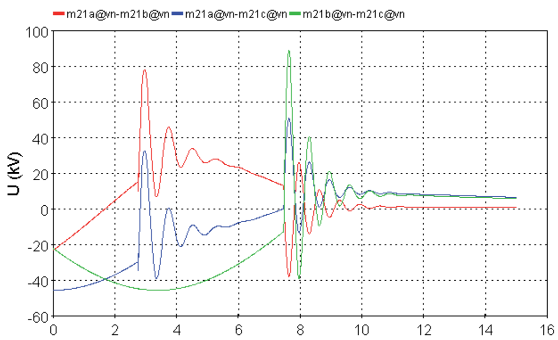


Fig. 20. Line overvoltages on the HV side of the distribution transformer.

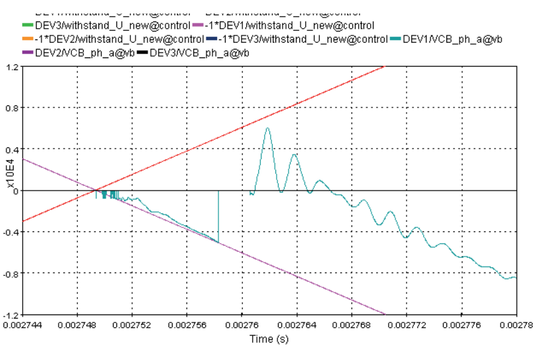


Fig. 21. Detailed view of the restrike on the circuit breaker terminals at the initial moment of the transient recovery voltage in phase A.

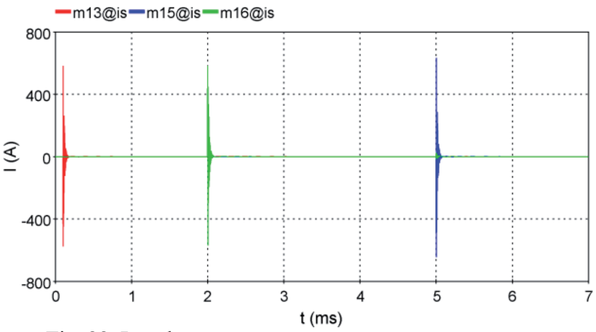


Fig. 22. Inrush currents

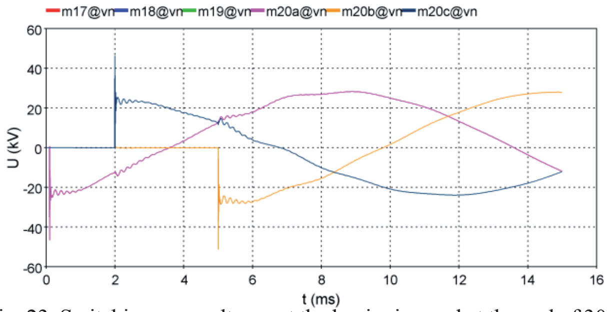


Fig. 23. Switching overvoltages at the beginning and at the end of 30 kV cable

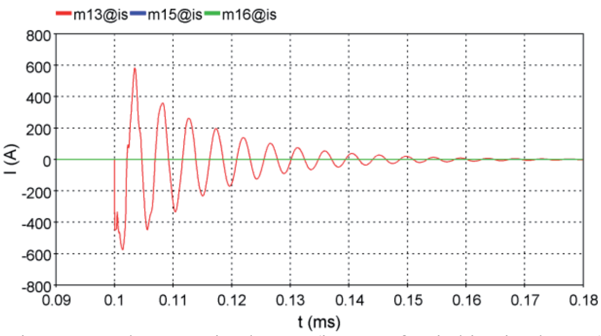


Fig. 24. Inrush current in phase A (instant of switching in phase A)

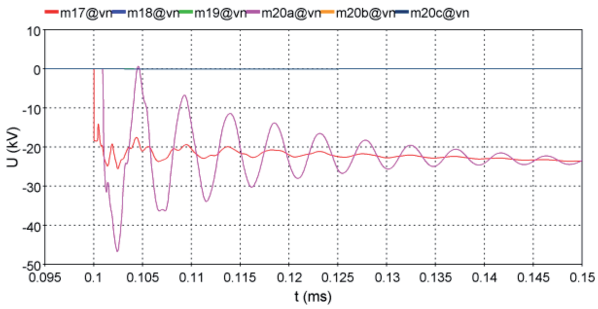


Fig. 25. Switching overvoltages at the beginning (curve m17) and at the end (curve m20a) of 30 kV cable (instant of switching in phase A)

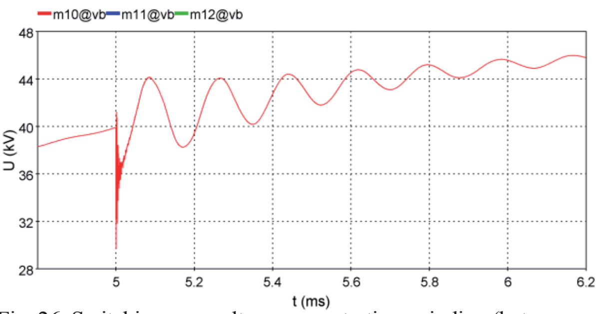


Fig. 26. Switching overvoltage across tertiary winding (between phases A-B) - instant of switching in phase B

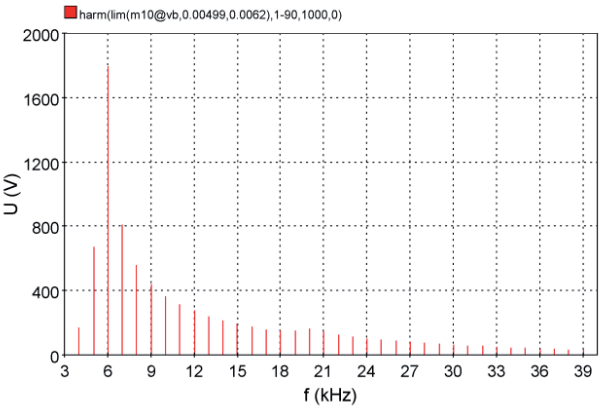


Fig. 27. LF overvoltage spectrum from Fig. 24: dominant frequency 6 kHz

Figures 22-27 show the waveforms of the calculated overvoltages and inrush currents for case B. From the results it can be concluded that there is no risk of resonant overvoltages on the tertiary winding of the transformer due to the switching of vacuum circuit breaker.

VI. Conclusion

During operation, power transformers are subjected to overvoltages that can cause failures. Therefore, it is necessary to check the amplitudes and the waveforms of overvoltages that can appear on the transformer terminals. For the analysis of fast transient phenomena, detailed models of transformers and other substation equipment (instrument transformers, surge arresters, circuit breakers etc.) are necessary.

The paper describes a high-frequency model of 400/110/30 kV power transformer with a rated power of 300 MVA, based on admittance matrix measurements. The model is verified using measurement results in the time domain. A detailed substation model is developed and an analysis of a lightning strike to a 400 kV transmission line is considered near an air-insulated substation where the observed transformer is located. The transferred lightning overvoltages between the transformer primary and secondary, as well as on the tertiary winding are calculated. The paper presents an analysis of the effectiveness of overvoltage protection using surge arresters and a verification of resonant overvoltages on transformer windings. The lightning overvoltage amplitudes on all elements of the substation are within allowed limits. The overvoltage frequency spectrum and transformer winding frequency response show that no possibility of resonant overvoltages in the transformer windings exists in the analysed cases. Energy stress on the surge arresters is within allowed limits. Analysed transients include switching of a vacuum circuit breaker in a 30 kV substation connected on one side with a 400/110/30 kV power transformer via a 40 m long cable, and on the other with a neighbouring 30 kV substation via a 200 m long cable. From the results presented, it can be concluded that there is no risk of resonant overvoltages occurring on the tertiary winding of the transformer during the switching of a vacuum circuit breaker.

The transformer model described in this paper is suitable for the precise calculation of overvoltages in the grid and for the analysis of transferred overvoltages. This can be of particular interest in the case of a transformer which has a large transformation ratio, such as larger transformers in power plants, if it needs to be determined whether the low voltage side, on which e.g. a generator can be connected, should also be protected with surge arresters. Measurements of the frequency-dependent matrix of the power transformer, from which the model is constructed, can be made relatively quickly in the factory during the production of the transformer or in the field (existing transformers that are in operation). In the case of field measurements, it is necessary to disconnect the transformer from the network. Through detailed simulations and modelling of all other components in the transformer station, it is possible to check the magnitude of the overvoltage, the effectiveness of the overvoltage protection (surge arresters) and the possibility of resonance occurring at different switching and operating conditions in the network. In this way, the occurrence of faults can be prevented, and the model enables accurate analysis of various operating events (e.g. post-mortem fault analysis, simulation of critical switching manipulations in the network, calculation of overvoltages and comparison with overvoltages recorded during operation, calculation of lightning overvoltages based on data from the lightning detection system, etc.). Simulation model presented in this paper could be used to check the potential for resonant overvoltages in the substation design stage, to check if a transformer may enter in resonance with the surrounding network (depending on different influential parameters such as cable length, transformer characteristics, etc.). In this way, appropriate measures could be implemented to avoid failures of HV equipment (for example improvement of transformer design, installation of RC snubbers, avoiding some "critical" switching operations leading to resonance, etc.).

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Prioritizing Diverse Observations or Issues from Safety Reviews at Nuclear Power Plants According to Possible Safety Impacts

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***Abstract*— Being a facility with potential for radioactive release, any nuclear power plant (NPP) is, over its operating life time, permanently subject to numerous safety reviews with different scopes and objectives. The reviews may be initiated and implemented by various stakeholders, including regulators, utilities or industry. Some of them are, by their nature, general and extensive in terms of different safety areas or safety attributes which are covered. An example of such a review is a Periodic Safety Review (PSR) which is promoted by the International Atomic Energy Agency (IAEA) and a number of national safety authorities in Europe and worldwide. The others may, depending on the objective, be targeted at particular safety area (e.g., ageing management or equipment qualification or safety analyses). Both of the mentioned cases (single general review or multiple targeted reviews over a time period) can generate an inventory of observations ("findings") or "issues" which need to be addressed but may be very different in their nature and implications, as well as in benefits or resources associated with their resolutions. For some issues a resolution may be straightforward. For others, it may require a feasibility study and identification of options for possible resolution. Also, in some cases the resolution is simply a "must" (e.g., discrepancy from licensing basis) while in some other cases it may be a matter of balance (e.g., effectiveness of maintenance program). Furthermore, while some of the issues may be directly related to operational safety (e.g., non-compliance with single failure criterion or aging-related degradation of safety features), for some others the link to operational safety may not be explicit (e.g., comparison of safety bases against the newly emerging methodologies or issues observed with regard to so called "soft factors"). The paper discusses types of different observations or issues which may come from general or targeted safety reviews and outlines some basic principles for their comparison and prioritizing with regard to possible safety impacts, which is many times needed for the purpose of developing an action plan for safety improvements.**

***Keywords* — operating NPP, safety review, safety issues, prioritization, ranking.**

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I. Introduction

ANY operating nuclear power plant (NPP), as a facility with potential for radioactive release, is subject to numerous safety reviews with different purposes and objectives. Some of the safety reviews are, by their nature, general and extensive in terms of different safety factors or safety attributes which are covered. An example of such a review is a Periodic Safety Review (PSR) which is promoted by the International Atomic Energy Agency (IAEA) and a number of national safety authorities, [1], [6], [14], [15] and [16]. PSR is many times used as a means for verifying whether a plant which has been operated in long term (e.g., over decades) is still as safe as originally intended and particularly in the context of new safety standards which have come into place after the time of plant's initial operation. The other reviews may, depending on the objective, be targeted at particular safety factor (e.g., ageing management or equipment qualification or safety analyses). The reviews may be initiated and implemented by various stakeholders, including utilities, industry and regulators. Both of the mentioned cases (single general review or multiple targeted reviews over a time period) can generate an inventory of safety issues which need to be addressed but may be very different in their nature and implications, as well as in benefits or resources associated with their resolutions.

Safety issue generated by a review can usually be characterized in terms of the three general attributes:

- Directly connected to nuclear safety (for considered issue, a direct link to nuclear safety can be established; for example, an observed deviation from the requirements relevant for nuclear safety); the category will here be referred to as "DS";
- Re-evaluation of nuclear safety basis (e.g., adequacy with regard to safety assessment standards or methods); the category will here be referred to as "RS";
- Related to "soft factors" (e.g., human factors engineering, organization for safety, safety culture and similar) or non-nuclear safety issue (e.g., industrial hazard); the category will here be referred to as "SF".

Each issue can usually be related to at least one of these three general attributes. Some issues may relate to more than one.

When assessing and prioritizing (ranking), a separate evaluation path would, in principle, need to be applied with regard to each of the three general attributes. The key is that ranking with respect to particular general attribute results with a certain (numerical) score, and that the scores for the three general attributes are directly comparable to each other, on the same scale. The score can be assigned by passing the issue of concern through multiple layers of ranking evaluation, with respect to predefined criteria. In the case that more than one ranking evaluation path (general attribute) applies, a rule can be set to take the highest score as a final issue rank.

One possible approach is generally discussed below.

II. Outlines of a General Approach

So-called 'defense in depth' (DID) is a basic concept in nuclear safety. It was defined as a philosophy to ensure that successive measures are incorporated into the design and operating practices for nuclear plants to compensate for potential failures in protection and safety measures, [2],[3], [4] and [5]. All safety activities, whether organizational, behavioral or equipment related, are subject to layers of overlapping provisions, so that if a failure should occur it would be compensated for or corrected without causing harm to individuals or the public at large. This idea of multiple levels of protection is the central feature of DID.

It then comes as natural to establish the approach for ranking of diverse safety issues in a way that it is based on assessing potential impact on DID. In its essence, the approach would consist of "measuring" or assessing the depth of remaining defense or remaining mitigation capability, provided that considered safety issue remains unaddressed. The approach would map the issue of concern into the DID structure (e.g., by failing or reducing the affected barrier capability) or into the accident sequences (e.g., by failing or reducing the affected mitigation function capability). In principle, both deterministic and probabilistic methods can be used for the purpose. Particular attention is to be paid to robustness of individual levels of defense and to mutual independence of levels of defense as important properties of DID.

The principles and elements of such approaches were, to various extents and levels of detail, used worldwide. For example, the approaches where remaining defense depth is estimated by counting of levels of defense were used to assess the safety of existing nuclear power plants and their elements are described in the IAEA publications such as [7], [8] and [9]. Similarly, the approaches where remaining mitigation capability is estimated (qualitatively, in terms of orders of magnitude) by mapping of the issue of concern into the relevant accident sequences are used in the US NRC Significance Determination Process (SDP), as originally described in references [10], [11] and [12]. Also, a similar approach is used in the industry risk informed applications (recognized also by the regulators). An example is risk informed in-service inspection where such approach is used to determine the remaining mitigation capability (or conditional risk) following an assumed failure or degradation of a pipe segment, [13].

In the case of a larger number of issues to be addressed (ranked) it can be expected that the process would be, for practical purposes, divided into two major steps, which can here be referred to as:

1. Broad ranking evaluation; and
2. Detailed ranking evaluation.

Broad ranking evaluation can be used for grouping of similar issues as well as for reviewing any particular issue in the light of other issues (from different areas of concern, such as PSR safety factors) which may be co-related. Sometimes, this may provide a different perspective on issue importance. By broad ranking, all issues from the inventory would be typically classified into several general categories of importance such as, for example: high (H), medium (M) and low (L).

The results of the broad ranking can also be used for initial prescreening done in order to identify the issues which can be directly sent to a corrective action program (CAP) normally existing in any NPP. Pre-screened issues which can be a direct input to a CAP (without further ranking evaluation) usually are of the two types:

- Issues requiring immediate attention and short-term resolution such as those representing Technical Specification violation or violation of current licensing basis; in principle, such issues, if any, would usually be broadly ranked with high (H) importance; for such issues no ranking is needed as their implementation is a "must"; this group of issues will here be referred to as "IRR" (immediate resolution requirement);
- Issues desirable to be resolved, which can be resolved at minimum effort and in a short time frame. Although these can come from any importance category, it is expected that most of them would come from low significance (L) category, relating to matters such as changes to procedures in non-safety domain, corrections to plant drawings or documents and similar. This group of issues will here be referred to as "LSE" (low significance and effort).

All the remaining issues (i.e., those surviving pre-screening) would be subject to a detailed ranking. Some of them would be later input into a CAP, based on the rank and used criteria. General flow chart is illustrated by Fig. 1.

Detailed ranking would, in principle, be based on assessing each issue against the three general attributes discussed above, "DS", "RS" and "SF" and corresponding predefined ranking criteria. In the process, particular issue would be initially related to one of these three general attributes (usually, most of the issues) or to more than one (usually, limited number of issues). It can be assumed that for each of those issues which are related to multiple general attributes the dominant general attribute can be identified, i.e., the one which would result with the highest score with regard to nuclear safety. Certain regrouping / subsuming of the issues may be done with regard to this. The effect would be that each issue in its finally defined form would be, before entering the detailed ranking evaluation, related to a single general attribute, "DS", "RS" or "SF". Thus, the issues would be effectively divided into three groups (as related to the three general attributes) and for each attribute a separate ranking evaluation path would apply. Passing through the respective evaluation path would result with a certain score assigned to the issue considered. A range of significance (a range of numerical values for the score achieved) would be defined for each of the three paths / general attributes in a way that the same scale would apply for all three paths. (For example, numerical value "3" for a score would represent the same safety significance regardless of whether the path was "DS", "RS" or "SF".)

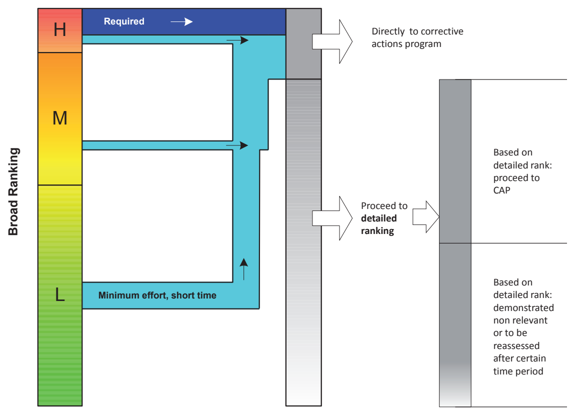

Fig. 1. General Flow Chart for Issue Ranking

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For resolution of any issue which would, as a result of the detailed ranking process, be input into a CAP, an appropriate corrective measure would need to be foreseen. Thus, in principle, each particular issue which will be, in the context of Fig. 1, forwarded to CAP, can be associated with particular corrective measure. Thus, the issue ranking and corrective measures prioritization become single process. In this process the issue achieves its numerical score through the evaluation path defined by the general attribute which was assigned to the issue, "DS", "RS" or "SF". Whichever the general attribute, this numerical score (final rank) would be achieved by passing the issue through several layers of ranking evaluation.

Having in mind the discussion at the beginning of this section, the first-layer evaluation in each path would be related to DID impact. The first two general attributes, "DS" and "RS", relate to DID either directly ("DS") or through the adequacy of DID assessment ("RS").

Therefore, the "DS" and "RS" evaluation paths can be associated with DID impact in a rather straightforward manner: by deterministically considering the status of "lines of defense" (LOD) (e.g., evaluation of safety margins) or by risk assessment (as assessed risk reflects the status of the LODs), whichever is considered more appropriate. Either evaluation would assess the significance of an issue on "depth of defense" (DOD) and it can be done qualitatively or quantitatively, depending on the issue addressed.

For the "SF" evaluation path, the relation to DID may not always be straightforward. However, it can usually be established through an assessment of issue's impact on potentially affected plant's "operational safety features" (OSF) which would in turn reflect on DID.

All these terms are further characterized in the sections below. But, in order to summarize the first-layer evaluation which relates to DID, it can be said:

- In the "DS" or "RS" path the significance of an issue is evaluated with respect to its DOD / risk impact;
- In the "SF" path the significance of an issue is evaluated with respect to its OSF impact.

The above mentioned first-layer evaluation provides means for primary ranking of safety issues. Finer sub-ranking can be achieved through the second-layer evaluation. As an example, the basis for the second-layer evaluation may be:

- Evidence from operating experience.

This kind of basis can be applied to all three paths.

Yet finer sub-ranking may be done by the evaluation of resources needed to resolve the issue of concern (i.e., budget for the respective corrective measure). This can be done assuming that all the "must-be-resolved" issues were input directly into CAP as the "IRR-type" issues discussed above. Thus, a third-layer evaluation of an issue can be foreseen on the basis of:

- Cost category.

For the purpose of issue ranking / corrective measures prioritization process this kind of evaluation would apply to all three paths and may be done as a simple qualitative cost category estimate.

Altogether, the process would result with a final score or priority for each issue / corrective measure. It is illustrated with generalized flow chart shown in Fig. 2 and Fig. 3.

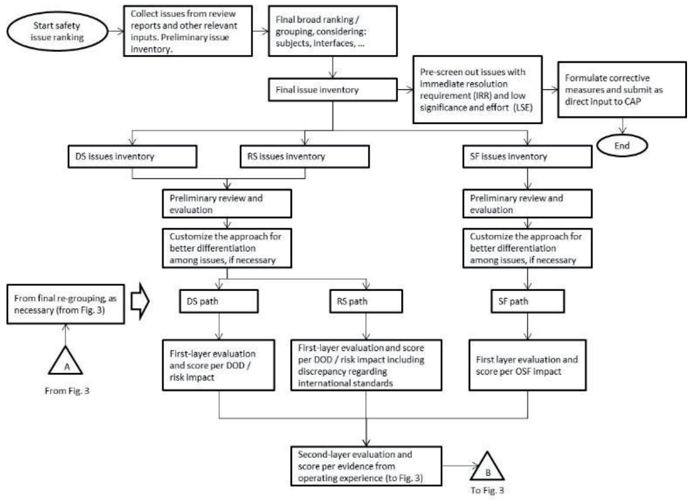

Fig. 2. General Flow Chart for Detailed Issue Ranking (1/2)

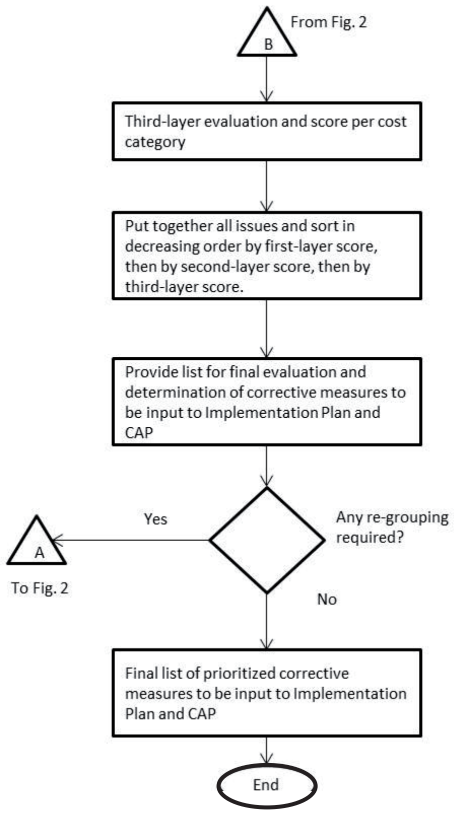

Fig. 3. General Flow Chart for Detailed Issue Ranking (2/2)

Broad ranking evaluation as well as three-layer evaluation for detailed ranking (as outlined above) are further illustrated and discussed in the sections below.

III. Broad Ranking Evaluation

During the broad ranking process, particular safety issue from any review area (e.g., safety factor in [1]) needs to be viewed in the light of other issues (from the same or from different review areas / safety factors) which may be co-related. This can be done through the process of grouping of issues from different review areas / safety factors, with correlated subjects (considering, also, associated possible corrective measures). The process would, usually, involve expert engineering judgment to certain extent, which would be facilitated if a ranking analysts' team includes members with expertise and experience related to all review areas / safety factors. Fig. 4 shows an example of a general flow chart for the interface impact assessment for this purpose.

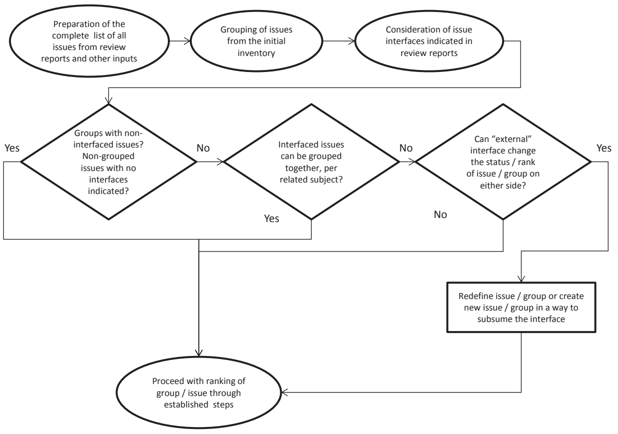

Fig. 4. Example Flow Chart for Interface Impact Assessment

As important part of the broad ranking evaluation, the issues would be grouped according to the three general attributes, i.e., for each issue it would be defined which detailed ranking evaluation path ("DS", "RS" or "SF") will apply. As shown in Table I below, different assessment and criteria at broad ranking would be applied for general attributes "DS" / "RS" as compared to "SF". The same table outlines high-level criteria for assigning low (L), medium (M) or high (H) safety significance to issues considered.

Table I

Example of High-Level Criteria for Broad Ranking

General Attribute (for Detailed)	Description of assessment criteria	Score		
		Low (L)	Medium (M)	High (H)
DS or RS	Impact on plant risk of a new PIE or of increased frequency of a PIE	Small	Significant	Major
	Impact of issue on a physical barrier to the release of radioactivity	Affected	Degraded	Seriously degraded
	Impact of issue on one or more levels of defense	Affected	Significantly affected	Lost
SF	Level of staff training, operational performance and plant procedures	Warrants improvement	Inadequate	Unacceptable
	Level of safety culture or organizational safety or associated subjects	Warrants improvement	Inadequate	Unacceptable

It is expected that broad ranking would involve subject matter experts for particular review area (e.g., safety factor in [1]).

IV. Detailed Ranking Evaluation – First Layer

IV. I General Attributes (Ranking Evaluation Paths) "DS" and "RS"

As mentioned above, for "DS" and "RS" path the first-layer evaluation represents an assessment of significance of an issue with regard to its DOD / risk impact. As an example, for DOD impact assessment a limited set of qualitatively defined end-states (pre-defined outcomes of an assessment) can be defined such as:

- "D1", Non-Relevant or Awareness Needed;
- "D2", Tolerable Long Term;
- "D3", Tolerable Short Term
- "D4", Not Tolerable.

The assessment (and respective criteria) for DOD impact evaluation can be based on the approaches such as counting LODs, e.g. [7] or [8]. In this context an LOD is defined as a system, barrier or human action (or combination of those) needed for providing protection against an initiating event. In principle, LODs exist at any or several of the levels of defense in depth. Considered issue is imposed upon the existing LODs and the remaining LODs (accounting for the issue impact) are then identified and counted. The result of an evaluation is then expressed as one of the above end-states.

If risk impact assessment is used instead, it can be based on the approaches such as Significance Determination Process, [10], [11] and [12], or on industry approaches such as the lookup tables in [13]. Same or similar set of predefined end-states can be used as above.

Fig. 5 below is an illustrative example of a set of criteria for assigning the end-states in the DOD impact assessment, inspired by [7]. ("S" refers to a "strong" LOD while "W" refers to a "weak" LOD.) It is noted that the figure is illustrative and without pretension to establish the actual criteria or definitions of "strong" and "weak".

In the case that risk impact assessment is used instead, a set of criteria can be derived from the mentioned US NRC SDP or directly based on Regulatory Guide 1.174, [17].

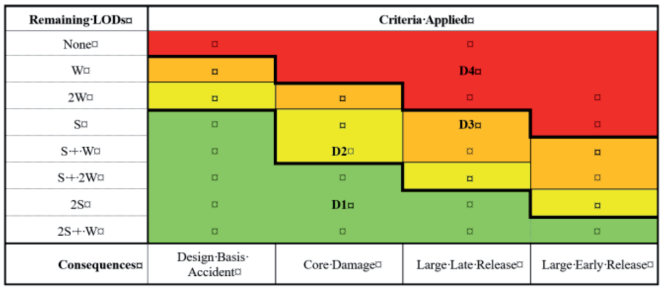

Fig. 5. Illustration of Criteria for DOD Impact Assessment

A concept for counting of LODs is illustrated by Fig. 6. There are six specific points in the accident progression, from an initiator to a consequence, "through" the LODs, which are indicated in Fig. 6:

- Point 1: Occurrence of an initiator. For some initiators (most of them, actually), one or more LODs already need to be broken for an initiator to occur.
- Point 2: Condition where, following an initiator, all but one design basis (DB) LODs have failed.
- Point 3: Condition where, following an initiator, all the DB LODs have failed. This still does not mean that reactor core damage would necessarily occur. For some initiators / accident sequences usually there are provisions in the Emergency Operating Procedures (EOP) which, although not part of the DB described in Safety Analysis Report, represent valid additional LODs.
- Point 4: Condition where, following an initiator, all the DB LODs and all additional LODs have failed. This condition leads to reactor core damage.
- Points 5 and 6: Condition where reactor core damage has developed into an event with early or late radioactivity release, respectively. These two conditions are considered mutually exclusive, what is, also, indicated in Fig. 6: if early release has occurred, then any late release is not relevant anymore; if, on the other hand, the release is late, then early release has not occurred, by definition.

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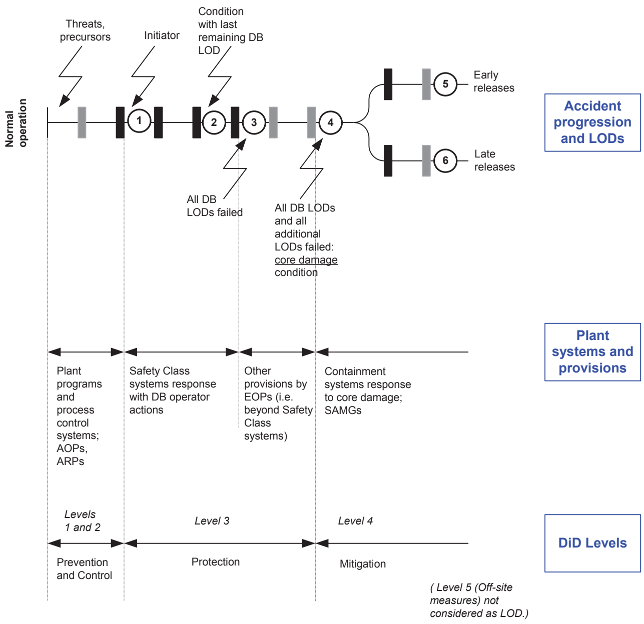

Fig. 6. Concept for Counting LODs

Once the DOD end-state (e.g., D2) is determined for particular issue, it would be translated to numerical score, as indicated by Fig. 7. (The analogous would be done in the case that risk impact states were used, instead.) Here, it is noted that in the case of D1 (green color in Fig. 5) additional sub-ranking criteria are provided since, based on the past experience, it is expected that considerable portion of the issues would be assigned this end-state. It is important to point out here that for the same end-state a numerical score on the "RS" path would, in principle, be lower than on the "DS" path. For example, for the state D2 a numerical score on "RS" path would be lower than on "DS" path. This is because in the case of "DS" an issue relates to the actual status of DOD (e.g., aging issue or environmental qualification issue) while in the case of "RS" an issue relates to potential or indicated status of DOD (which may or may not be confirmed when actual re-evaluation of safety basis is done).

DOD State	Functionality Impact	Score
D4	-	xx
D3	-	xx
D2	-	xx
D1	D1.3 Affects safety system or feature involved in DB accident sequence	xx
	D1.2 Affects system or feature involved in BDB accident sequence	xx
	D1.1 Impact limited to non-safety system not involved in BDB accident sequence	xx

Decreasing

Fig. 7. DOD States versus Numerical Score (Rank) for Path "DS" or "RS"

IV. II *General Attribute (Ranking Evaluation Path) "SF"*

As mentioned above, for the "SF" path the first-layer evaluation represents assessment of issue's significance with regard to operational safety features (OSF) impact. For this purpose, many times the OSFs can be divided into a limited set of categories such as:

- Operating Organization;
- Normal Operating and Administrative Procedures;
- Safety Management Systems;
- Radiological Protection and Other Occupational Hazards.

For assessment of an issue against each of the categories there are a number of techniques which can be used, such as those based on the gap analysis, check lists, and others. Once the assessment of particular issue is done, the issue of concern would be assigned a numerical score. An example of high-level criteria for OSF is given in Fig. 8. The range of the numerical score values needs to be calibrated against the numerical score values for "DS" and "RS" paths (shown in Fig. 7).

OSF Impact	Score
Significant shortfall identified or major element missing	xx
Gaps or areas not fully addressed	xx
Minor areas to be improved in order to bring in line with best international practice	xx
Minor issue which does not influence safety-related SSC, plant security or workers safety	xx
Impact limited to operational excellence, external confidence or public image of the plant	xx

Decreasing

Fig. 8. OSF States versus Numerical Score (Rank), Path "SF"

Thus, upon the completion of the first-layer evaluation the issue is given a first-layer score taken from the numerical values "xx" from Fig. 7 or Fig. 8 depending on the general attribute ("DS", "RS" or "SF") which was the basis for the evaluation. Since the scoring range is calibrated, scores of all different issues can be directly compared and, hence, prioritized.

V. Detailed Ranking Evaluation – Second Layer

For all issues input into the detailed ranking evaluation and being given a first-layer score finer sub-ranking can be achieved through the second-layer evaluation. As discussed above, a basis for the second-layer evaluation may be:

- Evidence from operating experience.

The evaluation of evidence would consider problems encountered with respect to a particular safety issue identified in plant-specific experience, plants of similar design (e.g., vendor owner's group), or generic industry-wide sources.

Table II shows an example of the criteria and significance scale for the evidence from operating experience. The significance criteria / scale can be applied to issues from all ranking paths (i.e., "DS", "RS" and "SF").

TABLE II

Illustration for Significance Scale for Evidence from Operating Experience

Evidence·from·Operating·Experience¤	Score¤
Issue·identified·as·plant·specific·problem¤	3¤
Issue· identified· as· vendor's· group· generic· problem·(no·plant·specific·identification)¤	2¤
Issued· identified· as· generic· industry-wide· problem·exclusively¤	1¤

Expert judgment and consultation with plant subject matter experts (SME) can be utilized to determine the plant specific, vendor-specific, and generic industry-wide information sources for a given safety issue. This evaluation would provide a second-layer numerical score for the issue, which may be used for sub ranking of the issues with the same first-level score.

VI. Detailed Ranking Evaluation – Third Layer

The issues with the same first-layer score and second layer score may further be sub-ranked. As already mentioned above, this can be done by considering the resources needed for resolution of particular issues (i.e., budget for the respective corrective measure). Thus, a third-layer evaluation can be performed which would be based on:

- Cost category.

Like in the case of evidence from operating experience under the second layer, this kind of evaluation can be applied under all three paths ("DS", "RS" and "SF"). It may be done as a simplified qualitative cost category estimate. An illustration is provided by Table III. (It should be noted that, from the cost perspective, favorable are those measures which are cheaper.)

Consideration of cost only at third layer reflects the fact that safety concerns (as well as problems from the past operating experience) are given higher priority over the budgetary concerns. Issues are always ranked by safety importance first.

TABLE III

Illustration for Significance Scale for Qualitative Cost Evaluation

Qualitative Cost Evaluation	Score
Less than X1 (EUR)	4
Between X1 (EUR) and X2 (EUR)	3
Between X2 (EUR) and X3 (EUR)	2
Greater than X3 (EUR)	1

VII. Concluding Remarks

The above outlined process would result with each issue / corrective measure being assigned significance in the form "f.s.t" where:

- "f": numerical score with regard to a first-layer attribute, DOD / OSF;
- "s": numerical score with regard to a second-layer attribute, past experience;
- "t": numerical score with regard to a third-layer attribute, cost of resolution.

Each of the three numerical scores is positive integer (e.g., 1, 2, 3…).

All the issues can then be sorted in descending order: first by "f", then for a given "f" by "s", and then for given "f.s" by "t". The process would result with a list of safety issues which would be sorted according to their significance. The significance sub-rank at second and third layer can be very important in the case of larger total number of safety issues: in those cases the numbers of issues with same primary rank can also be considerable and second and third rank would then provide for their sorting in decreasing order.

Very important part of the process is defining the ranges of numerical scores for the three paths, "DS", RS" and "SF" in a calibrated manner, because the final order of the list may considerably depend on this. This may involve an iteration or two in the process. Consistency checks may also help (e.g.: issue A is listed as more significant than issue B, and issue B as more significant than issue C; is issue A demonstrably much more significant than issue C?). This and some other parts would inevitably involve some expert judgement and discussions among the reviewers and subject matter experts.

It is very important to recognize that the ranking process as discussed in this paper is relative, i.e., the final result is a list of safety issues which are sorted by predefined significance. The results can be used to obtain an answer to the question: is issue X more than significant than issue Y or Z? However, no attempt was made in this paper to discuss the absolute importance, such as for example, at which place (item) can the sorted list be "cut off". The answer to this particular question is not simple and it would ask for some kind of "global assessment" (e.g. [1]) which would consider joint impact (synergy) of issues on lower side of "cut off" and implementation of the corrective measures for the issues on the upper side, as well as their time schedule (i.e., corrective actions implementation plan). This can be based on principles of risk assessment and / or deterministic principles such as those related to adequacy of safety margins and fault tolerance. Additionally, PSR [1] requires global assessment to provide safety justification for proposed long term operation [2] by evaluating the cumulative effects of both ageing and obsolescence on the safety and reflecting the combined effects of all safety factors (findings and proposed improvements).

In practice, a process like this was used, rather successfully, for the initial inventories with several hundreds of diverse safety issues resulting from periodic safety reviews of nuclear power plants.

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RELAP5/mod 3.3 Analysis of Natural Circulation Cooldown with One Inactive Loop for Nuclear Power Plant Krško (NEK)

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***Abstract* — The paper presents the RELAP5/mod3.3 analysis of natural circulation cooldown with one inactive loop for Nuclear Power Plant Krško (NEK). The aim of the analysis is to determine the limiting cooldown rates during operator recovery actions to minimize the effect of flow stagnation in inactive loop. Since this is typical asymmetrical transient, the RELAP5/mod3.3 NEK model with split reactor vessel model was developed (models of the reactor vessel and core were axially divided in two parts) and used for this analysis. The several transients of cooldown, with one inactive loop, for different time after shutdown (different decay heat) were performed. The extreme conservative assumptions were applied for the analyses, i.e. the complete loss of feedwater (FW) and auxiliary feedwater (AF), including turbine driven (TD) AF pump, and the cooldown has started after the SG is completely dry (inactive). The analyses show that the cooldown rate shall be significantly reduced, and, based on the results the procedure ES-0.2 "Natural Circulation Cooldown" was modified.**

***Keywords* — natural circulation, inactive loop, cooldown rate, RELAP5/mod3.3, Nuclear Power Plant Krško (NEK)**

I. Introduction

If the Reactor Coolant Pumps (RCPs) in a pressurized water nuclear power plant are stopped then a loss of forced reactor coolant flow will occur and the decay heat from the core to reactor coolant and from reactor coolant to the steam generators (SG) will be removed by natural circulation. Natural circulation is a heat removal process where reactor coolant system (RCS) flow is driven by density differences in the RCS fluid between the core and steam generators. If it is not possible to restart the RCPs, then it is required to cooldown and depressurize the system to bring it to injection point of RHR system.

Ideally, all of the reactor coolant system (RCS) loops will be active and participate in the natural circulation cooling process. However, if certain failures occur, one loop may become inactive and that SG would not be available for cooling the RCS. If a natural circulation cooldown is initiated at too high rate using the active SG, the transfer of heat to the inactive loop SG will lag the conditions in the remainder of the RCS, such that the density driving head from the downcomer/core region portion is negated. As the RCS flow in the inactive loop slows down, it can eventually stop or stagnate as a result of this excessive cooldown.

The inactive loop flow stagnation during a natural circulation cooldown can delay or prevent cooldown of the inactive loop(s), and extend the time to reach Residual Heat Removal (RHR) System cut-in and cold shutdown conditions. Also, the amount of condensate inventory used (Auxiliary Feedwater – AFW) will increase due to the time delay

Westinghouse document WCAP-16632 [1] provides the results of the analyses performed to determine the limiting cooldown rates and operator recovery actions that should be considered to minimize the impact of flow stagnation in the inactive loops. The results are given for typical Westinghouse plant configuration (4, 3 and 2-loops) with typical Westinghouse steam generators. Direct Work Request DW-04-001 [2] determines and describes the required changes of the EOP procedure ES-0.2 "Natural Circulation Cooldown" [3], which are necessary to prevent stagnant loop flow during natural circulation cooldown.

The purpose of this analysis is to perform specific NEK analysis in order to define the maximum RCS cooldown rates that can be achieved without RCS loop flow stagnation occurring in the inactive loop. The endpoint is to develop specific NEK Figure ES02-1 for ES-0.2 "Natural Circulation Cooldown" [3], with limiting cooldown rates vs. loop ΔT.

The Westinghouse method [1] for determining limiting cooldown rate cannot be applied to NEK with adequate confidence, so the specific analysis is needed. The analysis was performed using RELAP5/mod3.3 computer code [4]. The first step of the analysis is the development of NEK RELAP5/mod3.3 model with split reactor vessel because the natural circulation cooldown with one inactive loop is an asymmetrical transient. The split vessel model is not limited to the mentioned transient, but, with or without simple modifications, it can be used for the variety of asymmetrical transients.

The split reactor vessel model development required remodeling of the reactor downcomer, lower plenum, core, core bypass, Rod Control Cluster Assembly (RCCA) guide tubes and part of the upper plenum as well as the corresponding heat structures and control variables [5], [6]. The guidelines for mixing in lower and upper plenum is taken from SSR-NEK-AADB "Krško Accident Analysis Database" [7]. Accordingly, the ratio of mixing in lower plenum is 0,7:0,3. It was assumed that there is no mixing in upper plenum in order to elevate the temperature difference in hot legs

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and possibility of flow stagnation in the inactive loop (this is specific for natural circulation analysis with one inactive loop).

First, the steady state calculation was done and the results were compared to the case with standard vessel nodalization in order to confirm the correctness of model. Next, the analysis of natural circulation cooldown with one inactive loop was performed and, finally, Figure ES02-1 for ES-0.2 [3], with limiting cooldown rates vs. loop ΔT was developed.

II. Analysis and Results

2.1. Evaluation of Applicability of WCAP-16632 [1] to NEK

The results for the analyses of natural circulation with inactive SG are given for typical Westinghouse plant configuration (4, 3 and 2-loops) with typical Westinghouse steam generators. Specifically, this WCAP discusses the sensitivity analyses that were performed to identify the following important factors in determining a limiting cooldown rate to prevent flow stagnation:

1) number of RCS loops

2) active loop ΔT at the start of the cooldown

3) elevation of the top of the steam generator U-tubes with respect to the hot leg centerline

The maximum cooldown rate is dependent on the decay heat level of the core (based on time after trip) and the elevation from the bottom of the SG plenum to the top of the U-tube bend. The maximum allowable cooldown rate decreases as the SG elevation increases. Similarly, the maximum cooldown rate decreases as the decay heat level decreases.

For NEK this process would be straightforward if NEK SGs are those of the standard Westinghouse type. But, since NEK SGs are quite different, this method cannot be used with confidence since the method is based on similarity. NEK SG is rather high (distance from the HL centerline to the top of U-tubes is 14.77 m) and, in addition, ΔT vs. decay heat is different than in presented Westinghouse plants what can be seen from Table 1(ΔT depends on decay heat level and flow rate, i.e., flow resistances in the loops).

Table I

Active loop ΔT vs. Decay Heat (Comparison of typical Westinghouse 2-loop and NEK (RELAP5 calculation), values are approximate

Decay Heat	Westinghouse 2-loop	NEK (RELAP5 calculation)
Q (MW)	DT (°C)	DT (°C)
20	23	16,4
15	-	14,1
10	9,4	11,0
5	5,6	-

Accordingly, it can be concluded that the proposed Westinghouse method for determining limiting cooldown rate cannot be applied to NEK with adequate confidence, therefore the specific analysis is needed. The analysis is performed using RELAP5/mod3.3 computer code and it is presented below

2.2 Development of RELAP5/mod3.3 Split Reactor Vessel Model for NEK

The basis for the split reactor vessel model development is already existing NEK RELAP5/mod3.3 model, used for safety analyses and NEK Full Scope Simulator verification, and described in the NEK RELAP5/mod3.3 Nodalization Notebook [5] and Steady State Qualification Report [6].

The task required remodelling of the reactor downcomer, lower plenum, core, core bypass, RCCA guide tubes and part of the upper plenum as well as the corresponding heat structures and control variables. This is done by vertically dividing the existing RELAP5 control volumes of reactor pressure vessel in two equal parts. The junctions are also modified in the same way with additional adjustment of flow loss coefficients to match exact bypass flow values. Also, the corresponding heat structures are equally divided. The control variables that calculate mass, level and heat losses in the vessel and power in the core are modified. The model of the reactor kinetics was adjusted to the split vessel model in order to correctly analyse the transients for which the neutron kinetics behaviour is essential. The rest of the model, including control and protection system, remained the same as described [5] and [6].

The modelling approach without horizontal cross-flow connections between separated volumes inside reactor vessel was chosen to maximize the effect of asymmetrical transients. The guidelines for mixing in lower and upper plenum is taken from SSR-NEK-AADB "Krško Accident Analysis Database" [7]. Accordingly, the ratio of mixing in lower plenum is 0,7:0,3. Specifically, for analysis of natural circulation with one inactive loop, it was assumed that there is no mixing in upper plenum in order to elevate the temperature difference in hot legs and possibility of flow stagnation in the inactive loop.

The differences between standard vessel nodalization and split vessel nodalization are shown on Figure 1.

2.3 Evaluation of the Steady State Calculation

The steady state calculation was performed with NEK RELAP model with split Reactor Pressure Vessel (RPV) using the same assumptions and steady state criteria from [6] and the results show almost no differences compared to the case with standard vessel nodalization. The correctness of the steady state can be seen in Table 2 where comparison between NEK reference data and the calculated values for standard and split RPV model are shown.

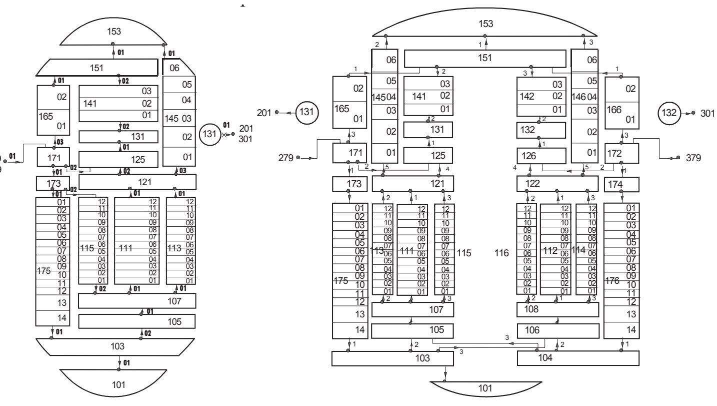

Fig. 1: RELAP5 Nodalization of NEK reactor vessel – standard and split vessel model

Table II

Comparison Between NEK Reference Data and Results of the Steady State Calculation for Standard and Split RPV Model

		NEK	RELAP5	
Parameter	**Unit**	**reference**	**Standard RPV model**	**Split RPV model**
1. Pressure	MPa			
Pressurizer		15.513	15.513	15.513
Steam generator		6.281	6.45/6.43	6.45/6.42
2. Fluid Temperature	K			
cold leg		558.75	559.65/559.46	559.45/559.44
Hot leg		597.55	596.92/596.92	596.94/596.90
3. Mass Flow	kg/s			
Core		8966.9	9034.3	4515.0/4515.1 (9030.1)
cold legs		4694.7	4718.0/4716.4	4717.8/4716.6
main steam lines		544.5	541.4/544.5	541.7/544.4
DC-UP bypass (2%)		187.8	184.8	93.8/93.8 (187.6)
DC-UH bypass (0.3%)		28.2	29.0	14.1/14.1 (28.2)
Buffle-barrel flow (1.25%)		117.4	116.8	58.1/58.1 (116.2)
RCCA guide tubes (2%)		187.8	186.3	94.2/94.2 (188.4)
4. Liquid level	%			
Pressurizer		55.7	55.8	55.8
Steam generator narrow range		69.3	69.3/69.3	69.3/69.3
5. Fluid Mass	t			
Primary system		-	131.2	131.3
Steam generator (secondary)		47.0	49.1/49.0	49.1/49.0
6. Pressure Drop	kPa			
reactor		290.0	297.1	297.3
core		171.0	174.4	174.5
Steam generator (primary)		234.0	211.0	210.6
RCS piping		39.4	38.6	38.5
7. Power	MW			
Core		1994.0	1994.0	1994.0
Steam generator		1000.0	996.6/1002.5	997.2/1002.3

2.4 RELAP5/mod3.3 Analysis of Natural Circulation Cooldown with One Inactive Loop

Since it is assumed that the heat transfer to one steam generator is not possible, this transient can be classified as the typical asymmetric transient. The detection of the flow stagnation in the inactive loop is based on the difference between hot leg temperature decrease rate. For that reason, this transient was analysed using modified NEK RELAP5 model with split vessel, as discussed in the chapters above. It was assumed that there is no mixing in upper plenum in order to elevate the temperature difference in hot legs and possibility of flow stagnation in the inactive loop. Based on the evaluation of the WCAP-16632 [1] it is supposed that the inactive SG will become completely dry, which is the most restrictive assumption.

The analysed transient assumed complete loss of feedwater and the unavailability of auxiliary feedwater in SG1, and, after a certain period the entire SG1 inventory is lost meaning that the SG1 is inactive. The following figures (Figure 2 to Figure 4) present the decay heat, the temperatures of the hot and cold legs and the mass flow rates in the loops for the analysis where the cooldown is not started. The analysis was done with control of pressure and level on primary and secondary side in order to stabilize the transient behaviour. On the contrary, the cycling of the SG PORVs/ Steam Dump would result in oscillation of the parameters (pressure, temperature) around the value presented herein. The differences of hot leg temperatures and loops mass flow rates clearly indicate the effect of the inactive SG. Table 3 summarizes the results for distinct decay heat values.

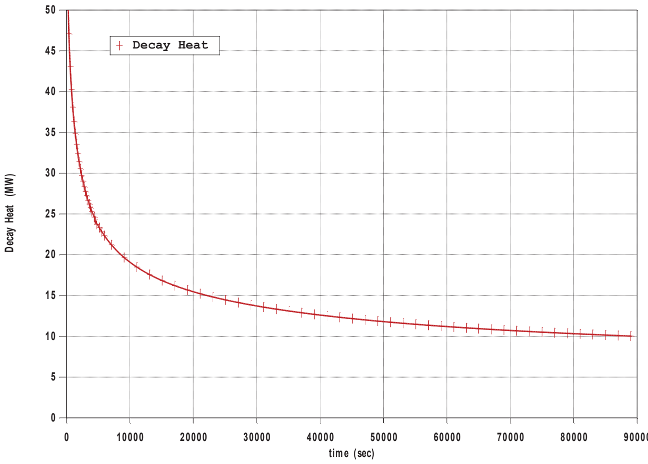

Fig. 2: Decay heat

Table III

Active loop DT vs. Decay Heat (RELAP5 calculation)

Q (MW)	DT (°C)	Time (seconds)	Time(hours)
20	16,4	8500	2,4
17,6	15,6	13000	3,6
15	14,1	22200	6,2
10	11,0	89000	24,7

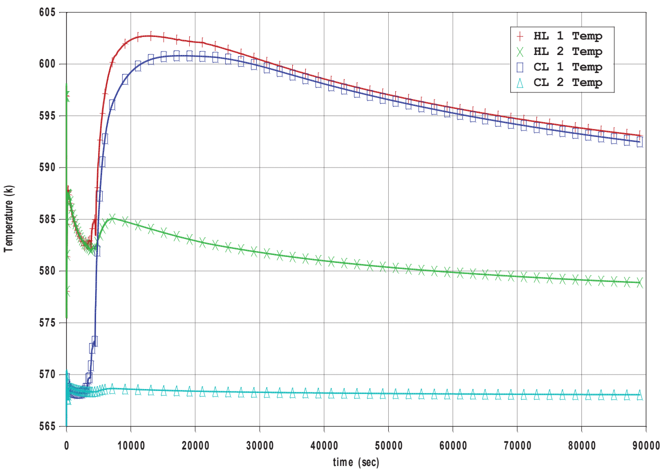

Fig. 3: Hot and cold leg temperatures (cooldown not started)

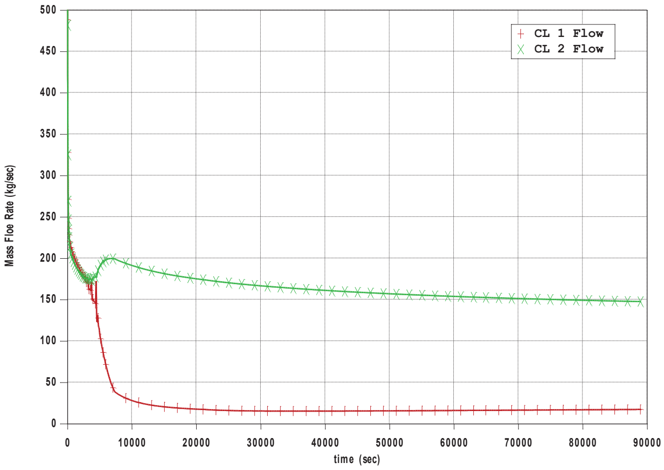

Fig. 4: Cold legs mass flow rates (cooldown not started)

The analysis of cooldown is presented in Figure 5 to Figure 10. It was assumed that the cooldown starts after initial phase of the transient (complete loss of FW and AFW in SG1), when the inactive SG becomes "dry". At time when decay heat is 20 MW the inactive SG is not completely dry, so cooldown is not started at this point. Therefore, the ***cooldown has started at times corresponding to 17.6, 15 and 10 MW decay heat*** (Table 3). The presented results are for limiting cooldown rates when indication of flow stagnation occurs, i.e. when it is determined that the inactive loop T_{hot} is decreasing at the slower rate than the active loop T_{hot}. It shall be noted that the analysis of cooldown is limited to the STEP 6 (beginning from STEP 6) and STEP 7 from the revised ES-0.2 procedure [3], because the STEP 7 is guidance for recovering from stagnant loop by providing the means of heat transfer from inactive loop. During these steps the operator is required to decrease core exit temperature (Figure ES02-1 [3]) to less than 287 °C prior to depressurization. It is questionable if the core exit temperature can be used for determining RCS temperature if there is an inactive loop. Additionally, hot leg temperatures in the loops differs a lot and, since there is almost no flow through inactive loop and cold and hot leg temperatures are almost equal, the inactive loop temperatures are not relevant for RCS temperature determination. According to EOP background documentation [8], the temperature of the active loop can be used when determining RCS temperature. Therefore, it is assumed that the cooldown for these steps ends when the active loop hot leg temperature reaches the temperature of 287 °C (560 K). After the depressurization to 137 kp/cm² the cooldown can be continued during STEPS 12 and 13 and it is limited according to the Figure ES02-1 at the same manner as in the STEP7.

The results shows rather restrictive cooldown rates (Figure 5, Figure 7 and Figure 9) what is caused by the extreme conservative assumptions (complete loss of FW and AFW including TD AF pump) and, to some extent, by the physical characteristics of NEK steam generator. The results are summarized in Table 4, from which the required figure ES02-1 is developed (Figure 11). It shall be noted that the ***limiting cooldown rate is determined when apparent difference exists between active and inactive HL temperature decrease rate***. On the contrary, i.e., when resulting temperature decrease rates do not differ a lot, the cooldown rate is very low what was considered to be over restrictive. This can be supported by the fact that the flow stagnation/reversal (in the inactive loop) did not occur for the extended period applying the constant cooldown rate (Figure 6, Figure 8 and Figure 10. It can be seen (Table 4 and Figure 11) that the limiting cooldown rates are, more or less, linearly proportional to ΔT. That can be expected because the limiting cooldown rates decreases exponentially with time, analogous to decay heat, and ΔT follows the same trend. It can also be judged that above ΔT =16,4°C (corresponding to 20 MW decay heat) the cooldown rate can be limited to 14°C/hr because, before that point, the SG1 would not become completely dry (inactive). Anyhow, this relaxation was not drawn on the developed figure ES02-1 (Figure 11: Maximum allowable cooldown rate - Figure ES02-1 for EOP ES-0.2).

Table IV

Limiting Cooldown Rates vs. Active Loop ΔT (RELAP5 Calculation)

Time after shutdown (hours)	Q (MW)	DT (°C)	Cooldown rate (°C/hr)
3,6	17,6	15,6	10,8
6,2	15	14,1	8,8
24,7	10	11,0	4,9

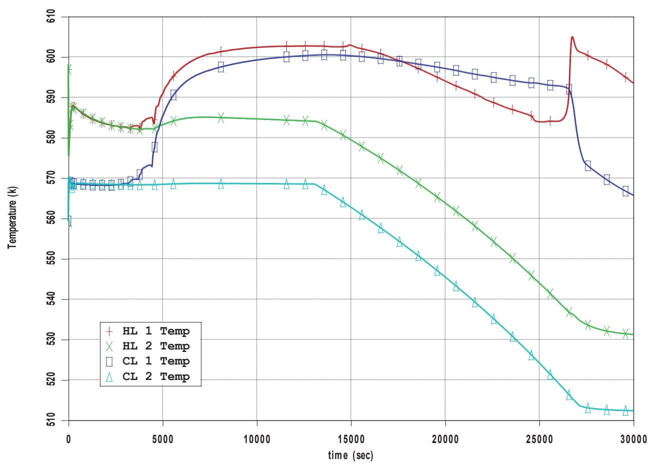

Fig. 5: Hot and cold temperatures - cooldown to 287 °C (560 K) ***from ΔT =15,6 °C***

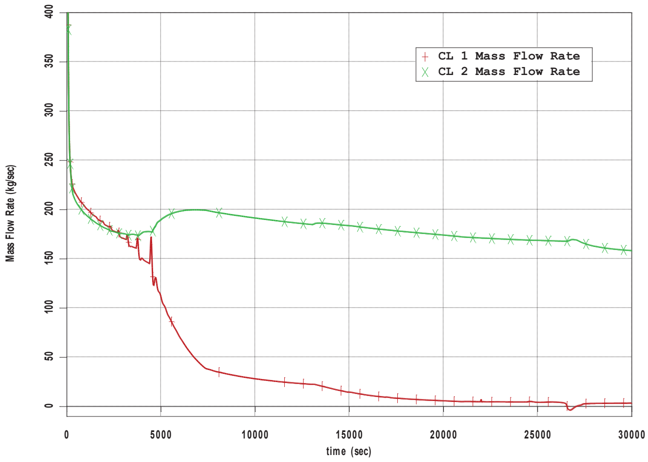

Fig. 6: Cold legs mass flow rates - cooldown to 287 °C (560 K) ***from ΔT=15,6 °C***

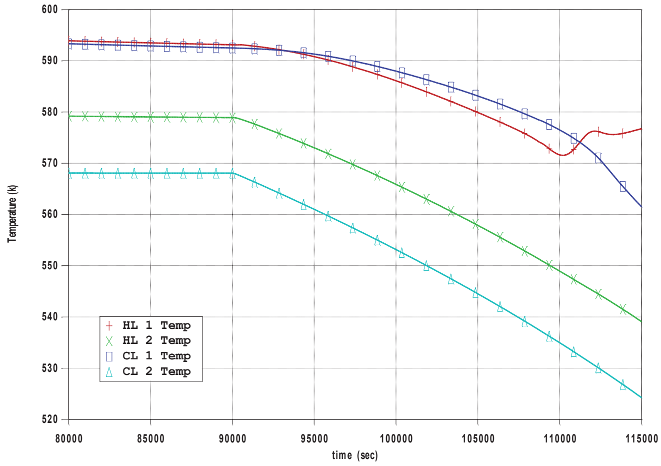

Fig. 9: Hot and cold leg temperatures - cooldown to 287 °C (560 K) ***fromΔT=11,0 °C***

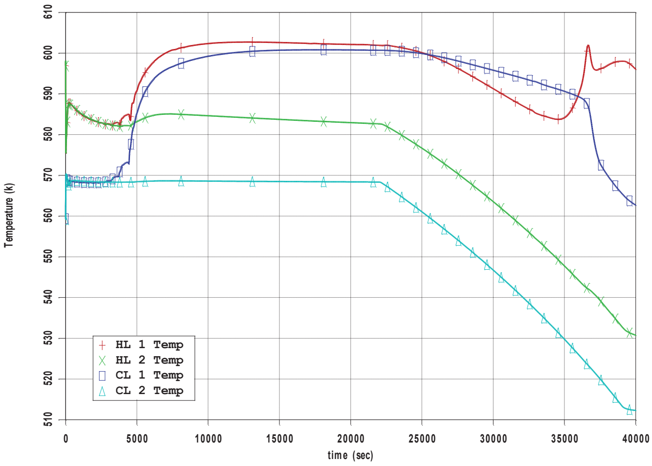

Fig. 7: Hot and cold leg temperatures - cooldown to 287 °C (560 K) ***from ΔT=14,1 °C***

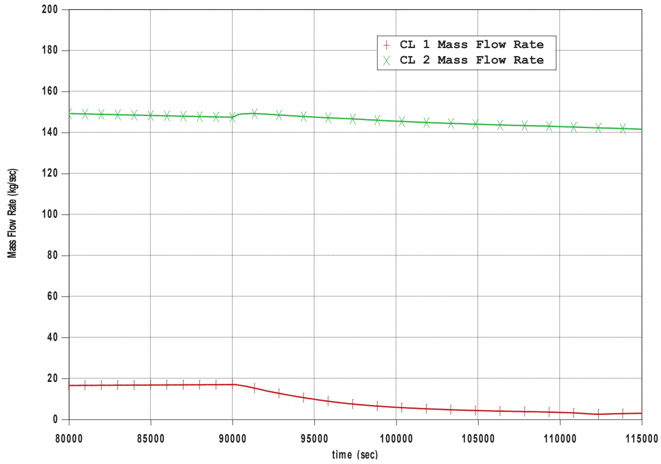

Fig. 10: Cold legs mass flow rates - cooldown to 287 °C (560 K) ***from ΔT=11,0 °C***

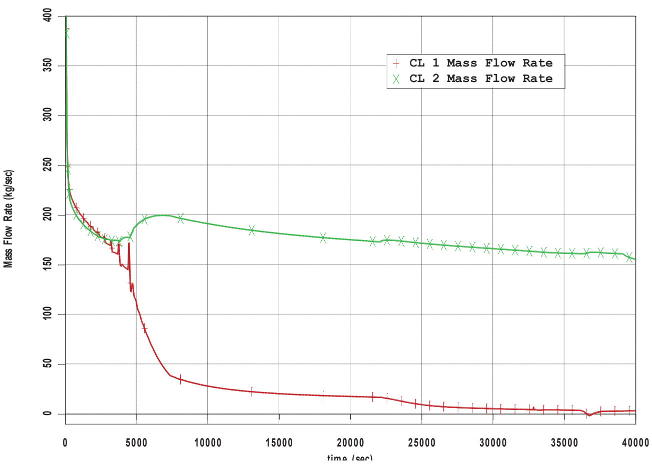

Fig. 8: Cold legs mass flow rates - cooldown to 287 °C (560 K) ***from ΔT=14,1 °C***

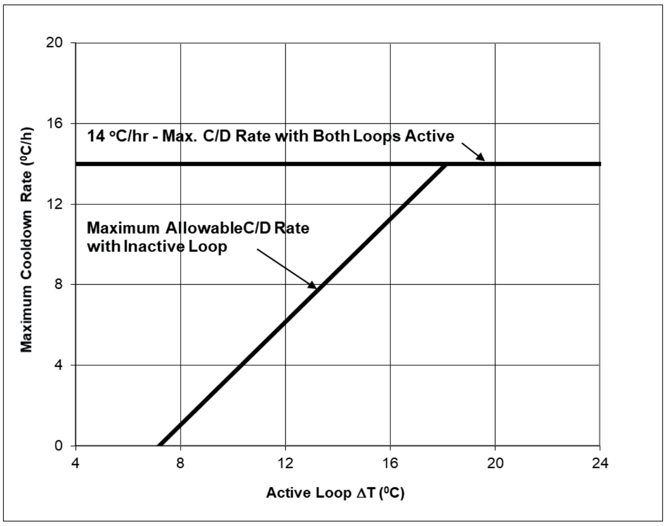

Fig. 11: Maximum allowable cooldown rate - Fig. ES02-1 for EOP ES-0.2 [3]

Conclusion

Determination of the maximum allowable cooldown rate with one inactive loop for NEK could not be done in straightforward way based on the instructions given in Westinghouse documents ([1] and [2]). The reason is rather different steam generators compared to standard Westinghouse SG types. NEK SG is rather high and, in addition, ΔT vs. decay heat is different than in presented Westinghouse plants. Taking this into account, the specific analysis was needed for NEK in order to determine maximum allowable cooldown rate. The analysis was performed using RELAP5/mod3.3 computer program. Since this problem is asymmetric the existing NEK RELAP model was changed, i.e., models of the reactor vessel and core were axially divided in two parts. After that the several transients of cooldown, with one inactive loop, were performed according to the guidelines from [1]. It shall be noted that the extreme conservative assumptions was applied for the analyses, i.e. the complete loss of FW and AFW (including loss of TD AF pump) and the cooldown has started after the SG is completely dry (inactive). The results show that the cooldown rate shall be significantly reduced (Figure 11), what was expected according to the analysis assumptions and, also, to a certain extent, due to the physical characteristics of NEK steam generators.

Based on this analysis and conclusion the procedure ES-0.2 “Natural Circulation Cooldown” [3] was changed as required by DW-04-001 [2].

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Improvement Possibilities for Nuclear Power Plants Inspections by Adding Deep Learning-based Assistance Algorithms Into a Classic Ultrasound NDE Acquisition and Analysis Software

Hrvoje Pavlović, Marko Budimir, Fran Milković, Luka Posilović, Duje Medak, Marko Subašić, Sven Lončarić

***Abstract* — The safety of nuclear power plants has always been one of the most important security issues in the industry in general. Numerous standards, techniques, and tools have been developed to deal specifically with the safety of nuclear power plants – one has specialised probes, robotized systems, electronics, and software. Although seen as a mature (or slowly evolving) industry, this notion about nuclear safety is a bit misleading – the area is developing in many promising new directions. Some recent global events will speed up this development even more. On the other hand, the industry is currently going through digital transformation, which brings networking of devices, equipment, computers, and humans. This fourth industrial revolution promises speed, reliability, and efficiencies not possible up until now. In the NDE sector, new production techniques and traditional manufacturing lines are getting to be lights-out operations (near-total automation). The same is most probably going to happen with the safety inspections and quality insurance. Robotics and automation are improving worker safety and reducing human error. The well-being of inspectors working in a hazardous environment is being taken care of. Most experts agree that the digitalization of NDE offers unprecedented opportunities to the world of inspection for infrastructure safety, inspector well-being, and even product design improvements. While the community tends to agree on the value proposition of digital transformation of NDE, it also recognizes the challenges associated with such a major shift in a well-established and regulated sector. The work presented in this paper shows a part of the project that aims to develop a modular ultrasound diagnostic NDE system (consisting of exchangeable transducers, electronics, and acquisition/analysis software algorithms), for applications in hazardous environments within nuclear power plants. The paper will show how the software part of this system can reach near-total automation by implementing various deep learning algorithms as its features and, then, testing those algorithms on laboratory samples, showing encouraging results and promises of online monitoring applications. Furthermore, future general prospects of this technology are discussed, and how this technology can affect the well-being of nuclear power plant inspectors and contribute to overall plant safety.**

***Keywords* — ultrasound, nuclear, safety, deep-learning, industry 4.0**

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I. Introduction

Detecting a defect, e.g. a crack in the material such as a metal or a composite using an automated deep learning-based procedure, is still an underdeveloped problem. Specifically, in ultrasonic non-destructive evaluation, autonomous defect detection methods are not widely used. Most inspections are still highly dependent on human experts and their experience in analysing certain types of data. Therefore, inspections are not yet automated, are slow, and are prone to human errors.

Analysis of ultrasonic inspection data has captured a lot of researchers' attention recently. In [1] authors proposed two popular deep-learning convolutional neural networks YOLO and SSD and adapted them for the ultrasonic anomaly detection task. In [2] the same authors showed that the EfficientDet-D0 model successfully detected all defects in the material. The biggest setback in the development of deep-learning models is the data needed for training such big neural networks. Although in a single inspection a lot of data is captured, this data is often protected by different NDA agreements and cannot be used after the inspection. Furthermore, in real inspections, flaws are rather scarce. On the other hand, metal blocks with synthetically implemented flaws are expensive and difficult to produce. In [3] authors extracted a few defects and pasted them on ultrasonic scans without visible defects. This way they managed to produce a large dataset and train a classifier that successfully detected all defects. In [4] a generative adversarial network (GAN) was used to generate a large amount of novel synthetic scans. Synthetic data was then used to improve the defect detector's performance. In [5] the same synthetic data generated by a GAN was shown to be of such high quality that human experts could not distinguish them from the real ultrasonic data. In [6] authors developed a novel convolutional neural network that outperforms all current models on ultrasonic defect detection. In [7, 8] authors managed to develop a deep learning approach that utilizes only non-anomalous data for training the defect, or anomaly, detector network. In [8] they show that the proposed network successfully detects all defects and outperforms standard classification approaches when a small number of anomalous data is present.

Developing a state-of-the-art defect detector on a limited dataset of ultrasonic data is one thing, putting the developed algorithms into real-world production is another. The developed algorithms are dataset specific and should be retrained if desired to be used on a challenge other than the one they were trained on while developed. Every inspection, used probe, and manipulator leaves its own mark on the data. A slight difference in the data could ruin the performance and reliability of the algorithm. Furthermore, for each inspection challenge, a novel module should be developed.

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For example, separate modules and algorithms should be used for detecting defects in metal blocks and in bolts. Since there are still no official qualification protocols for deep-learning algorithms in non-destructive evaluation, developed algorithms can only be used as an assisted analysis module. These algorithms can filter out the data that the inspectors need to look at, thus making the analysis much faster and more reliable.

Reliable and functional NDE systems that can compete as solutions for the Industry NDE 4.0 cannot only rely on the software support based on the deep learning and smart defects detection algorithms. An important part of the technology is, as well, the design and creation of hardware solutions that are both compatible and functional with the software backup and with the NDE inspection environment and conditions, no matter if those conditions are significantly elevated working temperatures, humidity, presence of ionizing radiation, high pressures, mechanical tension, etc. Within this project we work on a completely modular hardware-software solution, although in this work we will mostly focus on the software component, as we consider it the most important to discuss.

II. Data Acquisition

The ultrasound data acquisition for this work (and for such kind of research) is done by classic INETEC commercial multielement piezoelectric effect based phased array ultrasound transducers and an INETEC commercial pulser-receiver electronics device, instrument, used for excitation of the transducers and the data acquisition. The instrument, and the whole process, has been controlled and optimized by using a commercial INETEC acquisition and analysis software package. The smart part added to this software are the assisted analysis algorithms based on deep learning.

Fig. 1: A typical instrument for excitation of ultrasound transducers and data acquisition in ultrasound NDE inspections and experiments.

During the data acquisition process, the ultrasound phased array transducer sends a multitude of ultrasound acoustic radiation beams. In the moment of the data acquisition all the ultrasound beams are fired through the material. After the acoustic wave is reflected, the results are collected using the same transducers that did the acoustic beams firing. Based on the focal laws defined for the transducer by the user and additional signal processing, the final ultrasound scans, ready for data analysis, are obtained. The data is encoded by the encoder position. This provides the analyst the information about the obtained data Cartesian coordinates in the x-y plane, while the depth of the data position (for example, when we look for defects and their depths) is calculated by using the sound velocity in the material. The data prepared in such a manner is served from the ultrasound instrument and cannot be modified further.

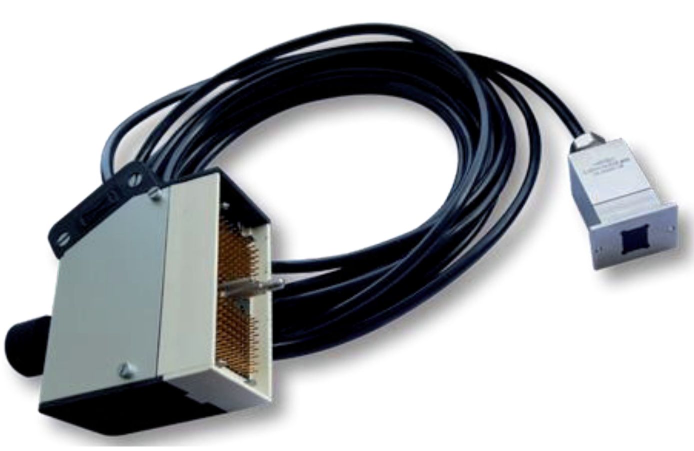

Fig. 2: A typical phased array ultrasound transducer for data acquisition in ultrasound NDE inspections and experiments. A phased array transducer consists of many small piezoelectric acoustically active elements that are independently excited both in the process of firing ultrasound beams and in the process of collecting the ultrasound waves reflected within the tester materials and configurations.

All the software modifications and editing of the scans later are of visual nature and do not affect nor influences on the obtained acquired data. Shortly, the data acquisition and its display is relatively straightforward and mature technology.

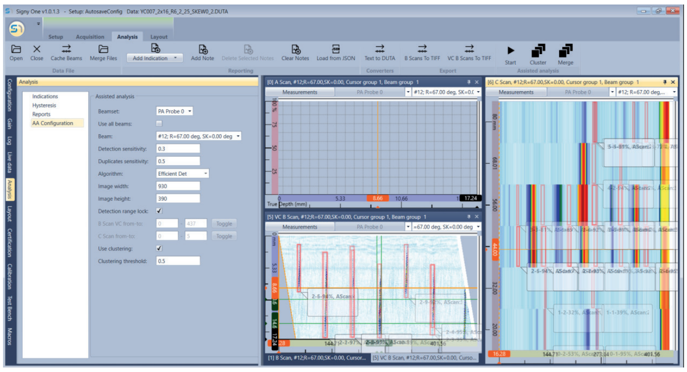

Fig. 3: Typical GUI image of an ultrasound acquisition and analysis software with the addition of the implemented deep learning modules which, when applied, mark, frame and store the defects coordinates on different scans. One can notice framed and labelled defects on the scans - this is the work of the deep learning assistant analysis algorithms.

III. Data Analysis

The main part of the assisted analysis are the data processing algorithms. Since human experts inspect the data by looking at different data visualisations such as A-scans, B-scans and C-scans, we choose the computer vision approach to defect detection. While some inspections require localization and sizing of the defects, some may require only classification. Depending on the task at hand, we develop different approaches and convolutional neural networks. We developed a generative neural network for augmenting the available dataset for training the defect detection algorithms in [5]. We also developed a self-supervised anomaly detection method in [7], and a supervised learning defect detection method on B-scans in [6] and on C-scans in [9].

IV. Modular NDE System

Assisted analysis of ultrasonic data is a combination of inspectors' expert knowledge, data acquisition and analysis software, and various algorithms for the detection of defects. Human experts in ultrasonic data analysis usually have to pass some education and qualification prior to analysis of the non-destructive testing data. The same procedure implies to the data analysis algorithms. Each developed algorithm has to be tested on data similar to the one we expect to see in the inspection on-site. Each type of inspection is unique and significantly differs according to the ultrasonic probes being used, the material being inspected, and the geometry of the inspected component. This is why we chose the modular approach to the development of assisted analysis software. For each type of inspection, we developed a specialised algorithm that performs the best for the situation.

The performance of the developed algorithms highly depends on the quality of the data being used. Furthermore, neural network architecture and training procedure also differs according to certain inspection. The best-case scenario would be training the neural networks before each inspection on the ultrasonic data taken from the same power plant. To date, there are no certification protocols for deep-learning algorithms. Usage of the developed algorithms should always be taken with good interpretability of their internal work. In the end, even after thoroughly evaluating the performance of the developed algorithms, the final decision on the state of the inspected material should be done by a human expert.

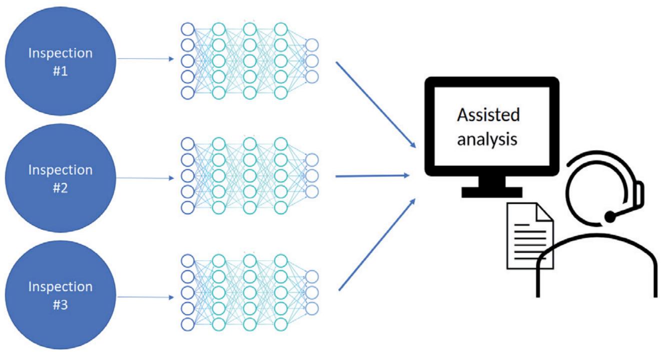

Fig. 4: A modular approach to the Assisted analysis

V. Future Technology Prospects

Considering the future prospects of this technology, as a subset of the NDE 4.0 industry, the first significant goal is the digital connectivity: on the one hand, digital connectivity between the different elements of the NDE inspection system and, on the other, digital connectivity of the input/output of the inspection system with the outside world. Therefore, in the first place, it is necessary to know the characteristics of the specific NDE inspection system, analyse them, and, thus, propose where to go and how to move forward. There are several types of NDE inspections: in-line inspection (of manufactured pieces), maintenance at the workshop inspection, and maintenance in-service inspection. Each of them has a series of characteristics that determine the steps to be taken and to reach digital connectivity. In any of the inspections the information involved is the same: inspection requirements and input information, inspection procedure (including essential variables, scan plan, and calibration settings), and inspection data (data from NDE sensors and their position). The content, quantity, and complexity of the information will depend on the requirements and characteristics of the components examined. In principle, any type of inspection system can lead the way toward NDE 4.0, but first it is necessary to analyse its characteristics, the investments to be made, and the benefits to be achieved. The final balance, positive or negative, will tell us the way to go.

VI. Conclusion

According to the recent breakthroughs in developing automated defect detection algorithms, we can be sure that the automation of non-destructive inspection is a trend you cannot avoid. Industry 4.0 will bring a lot of innovations that will revolutionize the safety inspections of nuclear power plants, oil and gas pipelines, and many more. More and more research papers show that successfully and more importantly, reliably detecting all defects in the inspected material is possible while speeding up the analysis many-fold. Therefore, the industry should prepare and start adapting the protocols toward assisted and even completely automated inspections. Implementation of such algorithms will contribute to the healthy state of the inspected power plants and reduce the downtime of such systems. Inspectors' tasks will become less tedious, and total automation will completely reduce human exposure to harsh conditions such as radiation, high temperature, and high humidity.

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