DISCUSSION MEETING

SUMMARY

Study Committee C5

Electricity Markets and Regulation

August 29, 2024

Chairman: **Alex Cruickshank**

Secretary: **Yannick Phulpin**

Incoming Secretary: **Anthony Giacomoni**

Special Reporters: **A. Moser (PS1), Samir C. Saxena (PS2), Anant Venkateswaran (PS3)**

1. INTRODUCTION

The 2024 discussion meeting of Study Committee C5 was held on August 29th, in room Havane at the Palais des Congrès in a morning and afternoon session.

The scope of Study Committee C5 focuses on the analysis of the impacts on the planning and operation of electric power systems of different market approaches and solutions. This includes new structures, institutions, actors and stakeholders as well as the role of competition and regulation in improving end-to-end efficiency of the electric power system.

For the 2024 CIGRE Session, a total of 57 papers were selected based on the three Preferential Subjects (PS).

2. RUNNING OF THE MEETING

The Discussion Group Meeting was chaired by the Study Committee Chairman, *Alex Cruickshank*, with *Albert Moser, Samir C. Saxena, and A. Venkateswaran* as Special Reporters and *Yannick Phulpin* as SC C5 Secretary. *Anthony Giacomoni*, the incoming SC Secretary, recorded the spontaneous contributions.

3. CONTRIBUTIONS TO PREFERENTIAL SUBJECT 1

Eight (8) papers were accepted for PS1 with one paper each from Colombia, Germany, Japan, Singapore, two from India and one international paper. Under PS1 the following sub-topics were identified:

- Responds to dynamic changes in the market environment and able to withstand external shocks.
- What markets and regulations have proven resilient so far and are still efficient and successful?
- Governance and institutional arrangements that assist resilience: who makes the decisions and takes the risks?

They cover several topics with respect to resilient markets:

- Price caps to cope with high price volatility.
- Fuel reserves to cope with threats to energy security.
- Further cross-sectoral market integration and further integration of DSM into markets to better utilize available resources.
- Incentives to encourage operational resilience.

In total there were eight (8) prepared contributions and several spontaneous questions and comments from the floor, as well as via the SparkUp tool. Overall, it was a very lively and interactive session.

The Special Report summarized each PS1 paper and poses the following six questions to invite contributions for the Group Discussion Meeting (GDM). Alongside each question, the submitted contributions are also summarized to provide a complete overview of the deliberations at the GDM.

<u>NGN Showcase presentation for Preferential Subject 1</u>

The GDM started with a presentation of an NGN Showcase on "Comparing the Co-Optimized and Market-Based Allocation of Cross-Zonal Capacity for the Exchange of Balancing Capacity", presented by Claire Lambriex, Germany.

Q1: What are the biggest challenges and lessons learnt when applying price caps on electricity in your jurisdiction to cope with high price volatility, especially following the Ukraine war?

<u>Prepared Contributions:</u>

- A. Moser, Germany

The energy crisis in Germany worsened in 2022 due to the loss of Russian gas exports, which led to a sharp rise in gas and electricity prices. Immediate measures were taken on the basis of an EU framework regulation. These market interventions included a price cap for consumers and a levy on surplus revenues from lignite-fired power plants, nuclear power plants and larger wind and solar power plants. The absorption of surplus revenues in particular failed due to its late implementation, which was only triggered by the crisis, as well as the difficulties in identifying revenues on forward markets and the exclusion of coal-fired power plants in order to avoid a fuel switch to natural gas.

- B. Harrison, Australia

The Reliability Standard establishes the critical market price settings (e.g. price caps and price thresholds) supporting the effective operation and investment in the NEM and driving contract volumes and prices. The Australian Energy Market Operator (AEMO) provides a range of information to the market to identify investment opportunities and risk hedging requirements to meet forecast demand over time ranges from 36 hours to 10 years in the future. If the market does not address forecast reliability gaps, AEMO can maintain reliability by market interventions, e.g. contracting and dispatching reliability reserves or even load shedding. The energy crisis required both, market interventions and an amendment of the critical market price settings. To address the root cause, the Australian Commonwealth Government took steps to limit price discovery for domestic fuel resources in the face of global export markets.

- Y. Kataoka, Japan

In Japan, because of the energy crisis, significant challenges arose for the weekly Japanese Replacement Reserve market, including high prices and a 56% capacity shortage. Therefore, a price cap was introduced for this weekly market. Also high-priced bids have been observed in the day-ahead reserve market for short term reserve products due to absent price caps. To address these issues, price caps were introduced for weekly trading, which helped to stabilize procurement costs despite ongoing shortages. To stabilize prices in the day-ahead reserve markets, volumes to be procured have been limited. Ongoing shortages in reserves have been addressed by the system operator through reserve utilization contracts with generation companies. In the future, it is planned to move the weekly trading of Replacement Reserve to a daily trading. It is expected that this measure will enhance market stability and mitigate risks associated with bidding behavior.

<u>Spontaneous Contributions:</u>

A lot of day-ahead market transactions are backed up by contract for difference. Only those generators and customers not having a contract for difference would be exposed to the price volatility and the need for price caps. Many smaller consumers are only hedged for one year so the prices would show up after one year. The application of price caps points to the inevitability of intervention during scarcity periods and supports the need for more orderly approaches to the recovery of investment costs such as capacity markets. Therefore, Germany is going to implement a capacity market because of the energy crisis. There seems to be issues with price caps when they do not reflect prevailing costs (fuel costs, procurement costs, etc.). As the system continues to decarbonize, price caps may be too low for long duration storage. In Ireland, there is a capacity market based on reliability options that protects consumers against high prices and puts the risks back on generators.

History has shown that prolonged periods of very high prices, regardless of whether they are efficient competitive prices or not, are politically unacceptable and that interventions in the form of price caps are inevitable. There has been a theoretical debate on the relative merits of energy only markets vs. those with capacity markets; however, practically speaking, the inevitability of intervention points to the need for more orderly mechanisms to promote investment in new capacity such as capacity markets.

Q2: Have strategic fuel reserves, e.g. natural gas, been required in your markets to ensure energy security? What are the experiences with such fuel reserves?

<u>Prepared Contribution:</u>

- V. Wise, Australia

Singapore is particularly susceptible to gas issues, as up to 95% of the power generation in Singapore is fueled by natural gas. During the energy crisis, existing provisions have been enhanced by a Strategic LNG Facility to further ensure energy security. Gas from strategic LNG facility can be used by generation companies, in case they are forced to produce electricity upon request by the regulator (Direct Supply Scheme) or in case, they voluntary provide capacity reserve (Standby Capacity Scheme). Because of the Strategic LNG facility, no load shedding has been observed during the crisis. Due to their success, Strategic LNG Facility and Direct Supply Scheme have been institutionalized.

- A. Maekawa, Japan

Japan is poor in energy resources and relies on imports from overseas for much of its fuel. Also, because it is an island country, there are limited means of energy transport. Therefore, oil and LNG reserves have been required to ensure a stable energy supply in case fuel supplies are disrupted or prices spikes are observed. Especially the Strategic Surplus LNG have recently been introduced following the energy crisis. Within this Strategic Surplus LNG, the government supports the strategic securing of surplus inventory by utilizing the procurement capabilities of generation companies. A fund provided by the government balances profits and losses of private business operators when using natural gas from Strategic Surplus LNG.

<u>Spontaneous Contributions:</u>

None

Q3: To what extent can better integration of different market segments, e.g. ancillary services and trading of scheduled energy, provide not only higher efficiency, but also higher resilience to markets?

Prepared Contributions:

- G. Doorman, Norway

European TSOs procure balancing capacity on national markets before market clearing of the European day-ahead market. However, exchange of balancing capacity between countries reduces costs, and moreover, co-optimization with the energy market provides further options for cost reductions and increase of social welfare. The European regulation allows for co-optimization and a sequential market-based approach when allocating transmission capacity for the exchange of balancing capacity. Modelling the two options to analyze the social welfare is a challenging task. This observation can be drawn from diverging results from different studies. In addition, co-optimization is a challenging project, which requires more issues than social welfare to be considered for decision making.

Spontaneous Contributions:

None – Note that the contributions echoed the introductory presentation by Claire Lambriex, Germany.

Q4: To what extent are regulatory incentives in your markets expected to better integrate industrial Demand-Side-Management? What is the role of industrial DSM in your country? Does this additional flexibility effectively contribute to market resilience?

Prepared Contribution:

- A. Giacomoni, USA

Currently, PJM, an ISO in USA, has 2,745 MW that participate in its Economic Demand Response Program and 7,216 MW that participate in its Load Management Program. Across the two programs together, there were 8,464 MW in total as some MW participated in both programs. The Economic Demand Response Program considers curtailment of loads within real time and day-ahead markets based on energy supply bids. The Load Management Program provides capacity reserves to the ISO through curtailment of load. In return, participating loads receive payments from the capacity market. Load management events are triggered by shortages of primary reserves. Control room does not precisely know, at what node within the nodal market system loads are curtailed, and does not fully trust in the performance of curtailments when triggered. Because Load Management Program provides steady revenues, it is the preferred market for curtailable load.

- V. Wise, Australia

The Singapore energy market provides two products for loads: Demand Response based on bids in the energy market and Interruptible Load based on bids in the reserve market. There is a price floor for Demand Response bids. The Demand Response contributed significantly to the market stability. While Interruptible Load can participate in the Primary Reserve market (9 seconds to 10 minutes), all Interruptible Load capacity thus far has been in the Contingency Reserves market (10 minutes to 40 minutes). The participation of loads in Demand Response and Interruptible Load has increased over the last years. To encourage further demand-side participation, the regulator introduced a Demand-Side Management Sandbox for 2023-2024. The Demand Side Management Sandbox relaxes compliance thresholds for Demand Response, and the penalty regime for both Demand Response and Interruptible Loads.

Spontaneous Contributions:

There can be an incentive issue if load is settled at the zonal level and participates in economic demand response at a nodal level.

Q5: What incentive schemes, e.g. financial incentives, or prestigious awards, are available in your country to improve operational performance? How much does this contribute to resilience of markets?

Prepared Contributions:

None

Spontaneous Contributions:

By incentivizing initiatives such as renewable energy investments, flexibility and participation in ancillary services like AGC, it has been observed that the transition to a more sustainable and resilient energy market is supported. With regard to improving operational performance, and also to concerns raised in respect of the importance of retaining some element of causer pays, capacity markets based on reliability options are a means of protecting end users from very high prices while at the same time retaining generators exposure to imbalance risks in the balancing market.

Q6: What regulatory measures are taken in your country to cope with non-technical losses? What are the experiences with these measures? Do they lead to higher market resilience?

Prepared Contributions:

None

Spontaneous Contributions:

None

4. CONTRIBUTIONS TO PREFERENTIAL SUBJECT 2

The Preferential Subject 2 on "Preparing for the future with moving targets" covers the following themes:

- Innovative approaches to markets and regulation to achieve climate and energy policy targets.
- The design and structure of electricity markets to support capital-intensive, climate neutral investments.
- Market and regulatory arrangements for supply, demand and storage that function across transmission, distribution and behind the meter resources.

A total of thirty-three (33) papers were selected from twenty (20) countries under the Preferential Subject PS2. The papers discuss the following broad areas:

- Electricity markets in conjunction with carbon markets.
- Electricity market simulations.
- Market coupling, transmission capacity allocation methodologies in the market.
- Distributed energy resources (DERs) and grid services.
- Grid connection (firm and non-firm), permitting.
- TSO-DSO interactions.
- Reserves, Ancillary Services (frequency control).
- Flexibility, balancing, guidelines and regulatory framework.
- Demand side participation in markets.
- Resource adequacy, Capacity markets, use of de-rating factors in capacity markets.
- Renewable integration including offshore wind integration.
- Virtual power purchase agreements, dedicated market segments for green energy.
- Energy storage systems and integration into markets.
- Artificial intelligence, data repository, data lake, forecasting techniques.

Nine questions were proposed for discussion in the Special Report:

1. Do electricity market designs need to be modified to accommodate a carbon price? If so, what changes are needed?
2. How do the Coordinated Net Transmission Capacity (CNTC) and Flow Based (FB) methodologies compare? especially in highly meshed networks?
3. What are the key differences in approaches for TSO-DSO coordination to facilitate effective participation by DERs in electricity markets? Does any approach facilitate inclusion of essential grid services / reliability services by DER? How can markets/regulation value the flexibility needed to face: i) uncertainty on transmission/distribution constraints, or ii) sudden frequency excursions?
4. With increasing penetration of renewables, the frequency excursions are increasing. Exposing loads to real-time prices makes zero marginal prices an opportunity rather than a problem to be solved. Can frequency linked real time pricing including imbalance handling pricing help provide signals to demand for flexible consumption? Further, can such linkage of the price signal also reduce balancing costs?
5. How can reliable data from market participants be ensured for fair calculation of costs?
6. How can interconnections, storage duration and flexibility be considered in capacity markets?
7. What are the key regulatory, technical and implementation challenges in using non-firm grid interconnections in different jurisdictions across the world, and how do they apply to facilities with energy storage systems?
8. How intraday markets and rescheduling are developed to cope with massive integration of renewables and demand-side management? How dynamic reserve procurement facilitate management of network congestion on account increasing RE penetration.

9. Should the growing number of large price sensitive loads (Such as Data Centres, Electrolysers, Industrial loads, crypto mining, etc.) be obliged to offer flexibility? How should price-responsive loads be modelled in the resource adequacy framework?

In response to the questions, twelve (12) prepared contributions were received and these are summarized below.

NGN Showcase presentation for Preferential Subject 2

The discussion started with a presentation of an NGN Showcase on "Research on Market Mechanism in Electricity-Carbon Coupling System: The Practice of CSG", presented by Nan Shang, China.

Question 1 dealt with market design modifications to accommodate carbon pricing.

Prepared Contributions:

- J. Bridge, Australia

Australia's history is of having an economy-wide carbon price for a short period. This has provided a perspective that when the carbon price was in effect, it facilitated changes to operations and investments consistent with decarbonisation without market change. However, a carbon price, on its own, is not sufficient and markets need to evolve to cover new missing markets that emerge with the new resource mix. He covered the perspective by looking at the past, present and future in the contribution.

- R. Yanzhe

The integration of the carbon price into electricity market designs is essential for driving the transition to a low-carbon energy system. However, this integration requires substantial modifications to existing market frameworks. By incorporating the carbon cost into the market clearing process, adjusting unit commitment and optimal dispatch algorithms, providing clear long-term investment signals, and ensuring supportive policy and regulatory frameworks, electricity markets can effectively accommodate carbon pricing. Ultimately, these changes will facilitate a more sustainable and efficient electricity market that supports global climate goals.

Spontaneous Contributions:

It may not be necessary to make any changes if the costs are reflected in the offers as a legitimate cost. In Ireland, generators are required to reflect the carbon price in their offers.

Carbon prices below $10 per tCO_2e have little effect on electricity prices, and much higher prices are needed to foster renewable energy development. However, such increases could face political resistance. Allocating carbon tax revenue to support renewables directly could help support renewable energy development.

In Morocco, they don't have a carbon price so imports into Europe need to be accounted for. In Europe you have to buy certificates to reflect your carbon content in generation. In Morocco, they do not have a carbon price. However, there is a European legislation under development, called "Carbon Adjustment at the Borders", which will apply to different sectors, including the electricity sector, which will require imports from Morocco to pay an equivalent amount on money to that paid by producers that emit CO_2 in the European Union system. The difficulty will be in knowing what emissions correspond to imports from Morocco, given that the energy exported can be from a multitude of energy sources, thermal power stations, photovoltaic plants, combined cycle plants, etc.

Question 2 dealt with Coordinated Net Transmission Capacity (CNTC) and Flow Based (FB) methodologies for congestion management.

Prepared Contributions:

- Mark Needham, Ireland

The background and need for flow-based methodologies was presented along with the need to comply with the Network Codes and add the SEM-FR Bidding Zone Border into a Capacity Calculation Region. Fundamental principles of both methodologies were described and the following comparison was also presented.

Criteria	Comparison
Economic -	In the case of the Celtic Interconnector there were no major differences in the capacity utilization.
Technical	Under CNTC bilateral exchanges may be limited by the predefined CNTC value. Note that it will be less than the available technical capacity. Under Flow Based the impact of bilateral exchanges are dynamically considered in market auction algorithms e.g. EUPHEMIA via PTDF factors. In the case of the Celtic Interconnector there were no major differences in the capacity utilization.
Implementation	As processes and procedures are already in place and well understood the existing Flow Based procedures are easier to implement.
Future extensibility	Flow Based techniques are the most advanced approached used across most technologically advanced grids in Europe.

Spontaneous Contributions:

The Iberian Peninsula does not apply flow based as their system is radially connected to the CORE system, and it yields no additional benefits. Why is this different for Ireland (given the UK is not part of the market)? In the context of SEM/France it made sense to do flow based. You have to look at the context for each project to determine what makes sense.

Question 3 dealt with approaches for TSO-DSO Coordination.

Prepared Contributions:

- N. Rachjarit, Thailand

In the context of Thailand, various approaches facilitate the inclusion of essential grid services and reliability services by Distributed Energy Resources (DERs). These approaches are critical for enhancing grid stability, reliability, and efficiency, particularly with the increasing penetration of renewable energy sources. The Renewable Energy (RE) Forecast Center plays a pivotal role in this integration process. The key approaches covered Data Exchange and Real-Time Monitoring, Advanced Grid Management Systems, Market Mechanisms and Financial Incentives, Infrastructure Enhancements, Policy and Regulatory Support. Regarding the valuing flexibility for transmission/distribution constraints and frequency excursions, various approaches in Thailand were mentioned covering capacity markets, LMP, dynamic tariff structures, flexibility services markets, ancillary services markets, fast frequency response (FFR) and performance-based incentives.

- N. Nair, New Zealand

Starting December 21, 2021, New Zealand Electricity Market transitioned to a 4-block Automatic Under Frequency Load Shedding (AUFLS) regime from their previous existing 2-block AUFLS for North Island Network (NZ has 2 AC islands namely North Island and South Island interconnected with a HVDC interconnection). This is an example of TSO-DSO coordination required for grid security. One of the outcomes of this change to AUFLS Code was to drop of the following items that related to flexibility i.e. extended reserve, extended reserve manager, extended reserve procurement notice, extended reserve procurement schedule, extended reserve provider, extended reserve selection methodology, extended reserve schedule, extended reserve technical requirements report, extended reserve technical requirements schedule and statement of extended reserve obligation.

Spontaneous Contributions:

None

Question 4 dealt with the increasing penetration of renewables and frequency excursions.

Prepared Contributions:

None

Spontaneous Contributions:

None

Question 5 dealt with reliable data from market participants be ensured for fair calculation of costs

Prepared Contributions:

- M. Hajibashi, Ireland

Data from market participants crucially shapes the market clearing optimisation and influences the overall cost by i) affecting the optimisation constraints, and ii) submitting the offers. Offers directly impact the objective function, while constraints by dictating the feasible solution space. Consequently, strategies to influence market prices are not limited to submitting non-cost-reflective offers. They can also strategically impact the feasible solution space by imposing unrealistic constraints. In uniform price markets, participants should offer their marginal costs. By limiting the use of technical offer data to influence market prices, market monitoring units can obtain more reliable commercial offer data over time. Cost benchmarking is an ongoing process, not a one-time activity. Gathering reliable data consistently is crucial to establishing a benchmark for the cost of different technologies.

Spontaneous Contributions:

None

Question 6 dealt with methods to consider interconnections, storage duration and flexibility in capacity markets

Prepared Contributions:

- T. Fuyuki, Japan

Japanese capacity market adopts a centralized capacity market. The market operator, OCCTO, calculates the required supply capacity for four years ahead based on future demand forecasts and secures the nationwide supply capacity through auctions. Prices are determined using a single-price method (pay as cleared), and the contract period is uniformly set to one year. The costs of securing supply capacity are borne by retail electricity companies and general transmission and distribution companies. To fairly evaluate the expected capacity value technology by technology, de-rating factors are set for pumped storage, storage batteries, and variable power sources, and the expected supply capacity of these power sources is determined by applying a certain reduction rate (de-rating factor) to the installed capacity.

Spontaneous Contributions:

None

Question 7 dealt with key regulatory, technical and implementation challenges in using non-firm grid interconnections

Prepared Contributions:

- Y. Tsukamoto, Japan

Since intermittent RES are not always at full output, some grid operators in various countries are introducing non-firm connection agreements. These agreements allow for earlier and lower-cost interconnection than system reinforcement by curtailing RES output or charging power of storage facilities under certain conditions. Non-firm connections might be applied either as an interim solution to defer grid reinforcement or under certain specific conditions as a long-term solution. Curtailment control methods based on non-firm connection contracts can be classified into three typical methods namely, “Static timed curtailment” or “Timed connection”, scheduled control method based on estimated grid condition and “Flexible Connection”, or “Active Network Management”.

- A. Papakonstantinou, Greece

Experience in Greece was shared. In Greece, non-firm connection agreements have already been introduced primarily as “static limitations”, where the power output of RES and storage stations is delimited to levels lower than installed capacity. In brief, the maximum power output per technology has been set according to pre-defined values. In some congested areas, the system operator offers connection agreements including terms allowing for congestion-related RES curtailments, until the planned network upgrade in the region is complete. A framework for adaptive limitations, calculated based on expected grid congestion (e.g. the following day), has not yet been established. Both methods namely, static and adaptive limitations have their own set of challenges which were presented.

Spontaneous Contributions:

We can see such variability in how different countries facilitate generator connection. In Australia, it appears that non-firm contracts are the default. This is different to other jurisdictions in the EU where firm connections is the default. Is there an objectively optimum way?

The positive side of non-firm is you get signals for storage as well. In addition, non-firm access can provide an important implicit locational signal for long term investment. However, there is concern on the bankability of such projects. Non-firm can be temporary or permanent. If it is permanent, it is a business decision. There are always two options and there is a need to balance curtailments versus paying for the upgrades and possibly having to wait for years to generate revenue.

The good thing about static limitations is they are known in advance. They may not be efficient, but they do not introduce additional investment risks.

If you don’t have nodal pricing then the value of congestion is not reflected in the price. You pay for what is firm and for non-firm you get it for free.

Given load growth over the next few decades, we need to keep investing in infrastructure. Non-firm connections will be helpful but we need to keep investing, which takes time.

Non-firm capacity agreements compete for grid access. An important aspect to consider is fairness. It also puts a lot of pressure on the system operators to have transparent dispatching processes.

The question is how you ensure you allocate grid access when the resource may never be used. If one generator connects they can use all of the capability. If an additional generator connects their capability is reduced.

Question 8 dealt with role of intra-day markets and dynamic reserve management.

Prepared Contributions:

- M. Kosakada, Japan

This contribution provides information that contributes to the study of the intraday market and rescheduling, based on the evaluation of the results of transactions to multiple markets (multi-use) using storage batteries located at the renewable energy generation site and the status of the improving the accuracy of renewable energy generation forecasts. A case study was presented. The results showed that multi-use of storage batteries in combination with the wholesale market (spot market) and the balancing market (Replacement Reserve for FIT (RR-FIT)) would lead to significant improvements. The case study also addressed the improvement of the renewable energy generation forecasting technology.

- G. Thorpe, Australia

Integrating non-firm resources into dispatch process. Many markets that are based on dispatch schedules and balancing arrangements to accommodate variations from schedule are moving to add intra-day markets to their existing day ahead regimes. These day-ahead arrangements are reducing gate-closure times like NEM of Australia which already has a short gate closure. At the same time, it is being recognised that greater certainty is needed to manage storage charge/discharge timing. Although it is noted shorter-gate closure can raise market power concerns, but shorter dispatch duration reduces the impact of it.

Spontaneous Contributions:

In India, dynamic reserves are procured and dispatched. Intraday markets provide flexibility by allowing trading closer to delivery time, which is crucial for managing the variability of renewable energy (RE) sources like wind and solar. India's electricity market has implemented strategic measures to address the challenges posed by the massive integration of RE and the growing role of demand-side management by introducing a real-time energy market in 2020 and a real-time ancillary services market in 2023. Rescheduling through Security Constrained Unit Commitment (SCUC), Security Constrained Economic Dispatch (SCED), and bilateral contracts further enhance grid resilience by allowing generation schedules to be adjusted within the day to better align with actual RE output, minimizing renewable curtailment and maximizing the use of RE. Dynamic reserve procurement and dispatch plays a critical role in managing network congestion, particularly in regions with high RE penetration. This is also a cost-effective solution to handle imbalances and localized congestion. For example, in India's Market-Based Tertiary Reserve Ancillary Services (TRAS), introduced in June 2023, the reserves are dynamically dispatched every 15 minutes, with provisions for excluding the generators from the areas of export congestion caused by RE integration. To get these reserves, the requirement of reserves is reviewed periodically on an annual, weekly, day-ahead and real-time basis.

Question 9 dealt with need for modeling of large loads (data centers, electrolyzers, etc.) in RA studies and the provision of flexibility from such loads.

Prepared Contributions:

- D. Lew, USA

Appropriate market participation models can provide a win-win situation for both large loads and the grid, by allowing large price-sensitive loads to save money by responding to wholesale market prices and not adding to load during grid stress events, and by providing flexibility to grid operators to balance the system and by reducing the need for new firm generation capacity resources. There are two types of price-response: in open-loop response, a load voluntarily responds to wholesale price signals. It may choose to not respond to high prices and pay more during high priced intervals. In closed-loop response, a load receives security-constrained economic dispatch instructions from the system operator. If the load does not comply, it can be penalized, and it also must settle the deviation at the real-time market price for that interval. Closed-loop response is superior to open-loop response for economic efficiency of the system but also for the large load itself. By actively participating in the market and submitting bids that reflect its willingness-to-pay, the large load optimizes its economic outcome. Whether large price-sensitive loads should be required to provide closed-loop response, and be dispatched. Requirements may be difficult because many loads are unable to accurately meet 5-minute set points. The threat of penalty is a downside risk. There needs to be adequate upside benefit to make this worthwhile for the load. A logical upside benefit would be for the load to not incur a capacity obligation.

- G. Thorpe, Australia

System Operators need knowledge of the net demand, irrespective of whether it is price sensitive or not. The question is how that knowledge is acquired? It is hard to see why large price sensitive loads should not be required to declare their likely demand at material times and conditions. What defines 'large' would need further consideration. Alternative approaches might be linked to two-sided market arrangements and to network access/connection capacities where applicable. The net impact of smaller price responsive demands is also important but impractical to advise, although distribution networks are likely to be best placed to assist on this point.

<u>Spontaneous Contributions:</u>

It is not as simple as just looking at spot prices but you have to look at how all the players interact with the spot market. Whether price responsive load are considered in resource adequacy depends on whether they are considered as a resource on the supply side.

5. CONTRIBUTIONS TO PREFERENTIAL SUBJECT 3

The Preferential Subject 3 on “Emerging markets and forms of markets” covers the following themes:

- Markets and regulations addressing the attributes of electricity that customers are seeking from the industry.
- Market based approaches to integrate community and distributed resources.
- New market approaches to overcome the barriers and limitations on current market designs.

Seventeen (17) papers were accepted for PS3 from twelve (12) countries.

The following questions were proposed for discussion in the Special Report:

1. What regulatory evolution is taking place in your country/region to support emerging and new types of markets? Please highlight the drivers and barriers and the incentive structures being provided in your region to help overcome the barriers and drive adoption.
2. In the context of energy transition where renewable penetration and electrification with sector cross-coupling increase; how do we design future electricity markets to ensure reliable operations and drive ongoing investments (Context - Marginal cost of renewables is not same as fossil resources)?
3. How are interactions between the new emerging markets and the existing systems/markets in place managed? What service requests from the market operator, TSO, DSO or a third party are handled by this new system/ market? For example, active or reactive power, maximum power limit, ramp rate, voltage or frequency regulation etc.
4. What types of operational information should TSOs, market operators, and market participants be required to provide in real or near-real time to other parts of the electricity supply chain, regulators or the government? How are AI applications used to exploit this information?

In response to the questions, nine (9) prepared contributions were received and these are summarized below.

Q1: What regulatory evolution is taking place in your country/region to support emerging and new types of markets? Please highlight the drivers and barriers and the incentive structures being provided in your region to help overcome the barriers and drive adoption.

<u>Prepared Contributions:</u>

- J. Bridge, Australia

There is a wide range of regulatory and market evolution occurring in the Australian National Electricity Market (NEM). Some proposed changes have succeeded while others have not. When thinking about what has succeeded, it is helpful to categories them in terms of the procurement mechanism and the degree to which there are centralised arrangements or are different in the different state jurisdiction. Stepping back, a pattern emerges. The initiatives that have been successful nationally have tended to be more technical in nature – less contentious, less stakeholders with conflicting views. As money becomes a greater aspect, and as changes impact a wider range of stakeholders, it’s apparent that it becomes harder to identify a “one size fits all” or even “one size fits most” solution, and so it degenerates into more fragmented overall solutions. And perhaps this is unsurprising. Reforms that have higher financial stakes make it harder for stakeholders to set aside their individual needs for the benefit of the overall system, and the wider the range of stakeholders affected the greater diversity in their situations and the harder it is to develop proposals that benefit everyone.

- N. Delaney, Ireland

Ireland and Northern Ireland is a weakly-interconnected island system with a high penetration of nonsynchronous generation, primarily wind. In 2017, a set of commercial regulated tariff arrangements were introduced to incentivise the provision of new ancillary or ‘system’ services to address the technical scarcities arising from the displacement of synchronous generation. At that time, the target was to be able to securely operate the island's power systems with levels of up to 75% system non-synchronous penetration (SNSP) by 2020, to meet the then target of 40% renewable energy in the electricity sector. Operating a small power system with high levels of SNSP introduces many technical challenges and operational risks, including rate-of-change-of-frequency (RoCoF), ramping capability, reactive power control, rotor-angle stability, voltage dip induced frequency event (VDIF), power quality and power oscillations. In Ireland and Northern Ireland, these technical challenges have been addressed through appropriate investment in performance capability, operational policy and the development of new tools. This has facilitated the progressive integration of higher levels of wind generation.

- M. Dolmatova, Russia

The regulatory evolution revolves around optimizing demand response (DR) mechanism in Russian electricity market that utilize Locational Marginal Pricing (LMP). This evolution is driven by

- the need to balance supply and demand efficiently,
- the need to enable consumers to play a more active role in the electricity market,
- allowing them to adjust their consumption in response to price signals, which can lead to cost savings,
- the need to provide System Operator and Market Operator with more flexibility in managing loads.
- Demand response mechanism is used to replace inefficient expensive generation (long term).

The growing presence of renewable energy sources, which are often intermittent and unpredictable, and the demand growth rate create a need for more responsive and flexible grid management both in terms of grid stability and containment or prevention of price spikes. DR mechanisms can help balance the fluctuations in electricity supply and demand.

- S. Wongpattanasiri, Thailand

Thailand is implementing several regulatory changes to support emerging and new markets. Key areas of focus include electric vehicles, operational resilience in financial services, digital transformation, and sustainability and environmental initiatives. Drivers include environmental sustainability, energy security, economic advantages, regulatory and policy support, technological innovations and consumer demand and participation. Barriers include regulatory and policy challenges, infrastructure limitations, technical and operation challenges and financial constraints.

<u>Spontaneous Contributions:</u>

Regulatory evolution is taking place in India. In Australia, rules in some states give certainty about when retirements of certain generators will take place. In other states where it is not possible, there are other models. The current market rules are not adequate to lead a transformation in the industry. States are sovereign in Australia and have the right to fragment if they wish. The issue is more the pace of change not the fragmentation of markets. In the United States, the Federal Energy Regulatory Commission (FERC) likes to keep the six markets it regulates somewhat consistent but allows for regional differences. ERCOT (Texas) is not under FERC jurisdiction as infrastructure does not cross state lines.

Q2: In the context of energy transition where renewable penetration and electrification with sector cross-coupling increase; how do we design future electricity markets to ensure reliable operations and drive ongoing investments (Context - Marginal cost of renewables is not same as fossil resources)?

<u>Prepared Contributions:</u>

- C. Dornellas, Brazil

Currently, Brazil has more than 1,200 wind and solar power plants. Due to operational issues unrelated to their management, these plants may experience "generation cuts", preventing them from fully exploiting all the installed capacity. Law No. 10,848/2004 and Decree No. 5,163/2004 have ensured compensation payments to generators impacted by these generation cuts for almost twenty years. Additionally, it was issued Normative Resolution No. 1,030/2022, with a new version in Normative Resolution No. 1,073/2023. The regulation also created an hour allowance, within which, even if the reason for the constrained off is external unavailability (the only one capable of compensation), the generation cut is borne by the generator. The situation nowadays is quite serious. For wind power, for example, which has a longer history, only 7.6% of cuts were compensated in 2022. In 2023, 0% of cuts were compensated. In the first half of 2024, again 0%. Some companies have already had their credit ratings downgraded by rating agencies, while others are at risk of covenant breaks. Due to generation cuts, project cash flows have not been sufficient to meet financial and contractual obligations.

- G. Hesse, Australia

The two major real-time electricity markets operating in Australia are the National Electricity Market (NEM) which connects the eastern states of New South Wales, Queensland, South Australia, Tasmania and Victoria; and the Wholesale Electricity Market (WEM) in Western Australia, which is electrically isolated from the NEM. Under normal operating conditions the NEM has no explicit value for capacity. There is also no explicit obligation for generators to make capacity available. The use of financial contracts around the spot energy price provides financial incentives for generators to make their capacity available and be dispatched into the market. Active trading in futures contracts provides visibility and forward price discovery. Since the early 2000's Australia's Renewable Energy Target (RET) has encouraged increasing production from new renewable generation sources, including domestic rooftop PV.

Spontaneous Contributions:

Capacity market designs must be designed carefully to not impact investment incentives in the energy market. Contribution in relation to the emergence in Australia of a variety of state level mechanisms to promote investment. It is remarkable that the NEM has continued to operate successfully under the same design for over twenty years. Nonetheless, arising from concerns that it is not providing sufficient timely investment signals, it would appear that a number of ad-hoc mechanisms are being put in place at a state level. Overlaying long term investment mechanisms on top of the physical spot markets risks dampening or potentially removing performance incentives in the balancing market necessary to promote dispatch efficiency. This is a significant risk and an absence of care in the design process (which takes time) can have very serious long term implications. A similar pattern emerged in recent years in Europe, where security of supply is a member state competency and various countries sought to put in place capacity mechanisms. These risks are mitigated to an extent in Europe by the State Aid process which requires member states to put in place the necessary energy market reforms prior to putting in place explicit capacity mechanisms. These reforms include: removing all constraints on the free price formation in the balancing market (including the removal of price caps), ensuring system service arrangements to secure sufficient reserves and other services are in place, ensuring demand side response is provided and developing efficient levels of interconnections with neighbouring systems. Where these reforms are in place or at advanced stages of implementation, only then can capacity mechanisms be considered and the design of these arrangements should be such that they result in the least distortion of the energy market. Having a regional power above the state level ensures that state interests do not prevail at the expense of other neighbouring states.

Q3: How are interactions between the new emerging markets and the existing systems/markets in place managed? What service requests from the market operator, TSO, DSO or a third party are handled by this new system/ market? For example, active or reactive power, maximum power limit, ramp rate, voltage or frequency regulation etc.

Prepared Contributions:

- M. Hajibashi, Ireland

Balancing capacity markets (BCM) interact with ex-ante energy markets and balancing energy markets

(BEM), depending on their design. In the Single Electricity Market (SEM), the current proposal is to schedule the BCM after the day-ahead energy market (DAM). Knowing the results of DAM, balancing capacity (BC) providers can determine their bidding strategy in BCM, while they have the opportunity to adjust their energy market position in intraday markets. As mandated by the Energy Balancing Guideline (EBGL), BCM winners are obligated to participate in the BEM based on their BC winning orders. This ensures sufficient capacity is available for EU TSOs in the BEM to manage real-time active power imbalances. Considering the interactions between BCM and BEM, it becomes evident that BCM winners may be better positioned to offer more competitive prices in the BEM, as they have already recovered some of their associated costs through the BCM. Specifically, due to the proposed time sequence in SEM for BCM and BEM, participants have no reason to account for their startup costs or the opportunity costs of not selling energy in DAM when making their BCM offers.

- B. Harrison, Australia

Australian National Electricity Market major existing security frameworks include:

- TNSP (TSO) obligations (S5.1) and Generator Performance Standards (S5.2)
- Frequency control ancillary services (FCAS)
- Network Support and Control Ancillary Services (NSCAS) – Australian Energy Market Operator (AEMO) is procurer of last resort for non-market ancillary services
- Market Directions – AEMO may require any act or thing to maintain or re-establish a secure or reliable operating state

Australian National Electricity Market is improving security frameworks for the energy transition with the following:

- Inertia Services Provider – TNSP led procurement – Operational 1 July 2018
- System Strength Service Provider – TNSP led procurement – enforceable by 2 Dec 2025
- Expanding existing FCAS with a 1 second market – operational October 2023.
- New transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition and to trial new sources of security services – transitional services guideline from AEMO due December 2024.

Spontaneous Contributions:

Hydro is one renewable source that can provide a very fast ramping service. DR and flow batteries are other sources that can provide fast ramping service. The energy transition is about power electronics and there is a strong interest now about microgrids. However, inverters can create instability. The other main issue is standards for inverter based resources. The standards are not consistent with what is good for the system as a whole. For local inertia service, Ireland has a fixed contract for six years.

Q4: What types of operational information should TSOs, market operators, and market participants be required to provide in real or near-real time to other parts of the electricity supply chain, regulators or the government? How are AI applications used to exploit this information?

Prepared Contributions:

- G. Hesse, Australia

The NEM and the WEM are both comparatively transparent markets. While the specifics differ, both markets allow participants to access large quantities of market data. For the NEM much of the available data is updated every five minutes; for the WEM similar data is updated every 5 minutes for real-time dispatch and every 30 minutes for the 2-day ahead horizon forecast. These align with the frequency of dispatch calculation in each market. The richness of these datasets make the use of analytical tools, including those developed using machine learning and/or AI, very advantageous. Given the size of the available data sets and frequency with which they are updated, tools for data management and visualisation are a necessity. Traders who can make sense of the data in an efficient manner are able to make timely and effective trading decisions.

Spontaneous Contributions:

None