ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

Market mechanisms and pricing rules to enhance low-carbon electricity markets efficiency

Author: Ignacio Herrero Gallego

Supervisor: Pablo Rodilla Rodríguez

Supervisor: Carlos Batlle López

Madrid

April 2018

Summary

Power systems are changing profoundly due to the necessary introduction of Renewable Energy Sources (RES), and as a result, there is an obvious need for significant upgrades in electricity markets. The ongoing transition to a low-carbon power system involves large investments in RES capacity, of which, the main contributors will be Variable Energy Resources (VER) such as solar and wind power. The characteristic variability and uncertainty of VER production creates new challenges for power systems, especially in their short-term operation.

This research based on qualitative and quantitative (model-based) analysis and a comparison of European and North American electricity markets, proposes market reforms in some key design elements of short-term electricity markets. In summary:

- The ability of bidding formats to represent the increasingly relevant operating constraints of generation units becomes critical. This calls for new and adapted bidding formats for new energy resources, such as storage and aggregators, both in the US and Europe. In European markets, bidding formats for conventional resources should also be significantly improved.
- The impact of VER on power prices is highly dependent on the pricing rules in place. Pricing rules differ in how non-convex offer components (e.g., start-up and no-load costs of thermal units) are reflected in prices. Non-linear pricing schemes use (discriminatory) uplift payments to compensate some of these costs, distorting efficient price signals. Linear pricing rules (tending to uniform pricing) provide more efficient incentives in the long-term, leading to more cost-effective investments.
- US markets should continue to explore linear pricing alternatives, but there is also a need to improve the allocation of uplift charges, in a way that does not hinder demand participation. European power markets apply a strictly linear (uniform) pricing approach that has derived in unnecessarily complex clearing algorithms. This becomes unsustainable as more complex bidding formats are introduced, making a welfare-maximizing clearing algorithm (as in US markets) preferable.
- VER introduce uncertainty in day-ahead market programs, which require corrections in the intraday timeframe. Producing intraday price signals is critical to incentivize market agents to provide updated information to market or power system operators. An alternative settlement system is proposed to achieve this objective in US markets.

Resumen

Los sistemas eléctricos están experimentando profundos cambios a raíz de la necesaria introducción de energías renovables (RES), consecuentemente, los mercados eléctricos deberían adaptarse a esta realidad. La transición a un sistema eléctrico bajo en carbono conlleva inversiones en RES que serán, en su mayoría, recursos intermitentes (VER) como la energía solar o eólica. La variabilidad e incertidumbre de los VER conlleva numerosos retos en la operación del sistema, especialmente en el corto plazo.

Esta investigación, a partir de un análisis cualitativo y cuantitativo, y una comparación de los mercados eléctricos europeos y de Norte América, propone reformas en algunos elementos críticos del diseño de los mercados eléctricos de corto plazo. En resumen:

- Es crítico que los formatos de oferta de estos mercados representen con detalle las restricciones operativas de las unidades de generación. Esto require nuevos formatos de oferta para nuevos recursos, como el almacenamiento o los agregadores, tanto en Europa como en EEUU. En los mercados Europeos, los formatos de oferta para recursos convencionales también requiren mejoras sustanciales.
- El impacto de los VER en los precios de la electricidad depende de las reglas de precio, que varían en función de cómo reflejen los parámetros de oferta no convexos (e.g., costes de arranque de unidades térmicas). Las reglas de precios no lineales usan pagos discriminatorios (*uplift*) para compensar alguno de estos costes, distorsionando las señales de precios. Las reglas lineales (tendiendo al precio uniforme) proporcionan incentivos más eficientes en el largo plazo.
- Los mercados en EEUU deben continuar explorando alternativas lineales para el cálculo de precios, aunque también se debe mejorar en la asignación de costes (del *uplift*) para no entorpecer la participación de la demanda. Los mercados europeos aplican precios estrictamente lineales, lo cual ha derivado en una excesiva complejidad en la casación del mercado. Esto resulta insostenible si se emplean cada vez más formatos de oferta complejos, y sería preferible una casación que maximize el beneficio social neto (como en los mercados americanos).
- Los VER introducen incertidumbre en el resultado del mercado diario, lo cual require correcciones intradiarias. Es crítico que existan señales de precio intradiarias para incentivas a los agentes a proporcionar información actualizada al operador del sistema o del mercado. Se propone un sistema de liquidación alternativo para lograr este objectivo en los mercados EEUU.

Acknowledgements

xxx

CONTENTS

LIST OF TABLES

List of Figures

List of Abbreviations and Acronyms

4M MC	Four Markets Market Coupling (Europe)
ACER	Agency for the Cooperation of Energy Regulators (Europe)
APX	Amsterdam Power Exchange (now merged into EPEX SPOT)
CAISO	California Independent Market Operator
CCGT	Combined Cycle Gas Turbine
CEER	Council of European Energy Regulators
CH	Convex Hull
CT	Combustion Turbine
DAM	Day-Ahead Market
ELMP	Extended Locational Marginal Pricing
EOH	Equivalent Operating Hours
EPEX SPOT	European Power Exchange
ERCOT	Electric Reliability Council of Texas
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FERC	Federal Energy Regulatory Commission (United States)
FMM	Fifteen-Minute Market (in the CAISO)
GME	*Gestore dei Mercati Energitici* (Italian NEMO)
ICP	Intraday Commitment Process
IEA	International Energy Agency
IR	Integer Relaxation
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LTSA	Long-Term Service Agreement
MIF	Maintenance Interval Function
MISO	Midcontinent Independent System Operator

MPP	Market Parties Platform (Europe)
MRC	Multi-Regional Coupling (Europe)
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
NSE	Non-Served Energy
NYISO	New York Independent Market Operator
OCGT	Open Cycle Gas Turbine
OMIE	*Operador del Mercado Ibérico de Energía* (Iberian NEMO)
PAB	Paradoxically Accepted Bid/Block
PCR	Price Coupling of Regions
PJM	Pennsylvania-New Jersey-Maryland (Interconnection)
PRB	Paradoxically Rejected Bid/Block
PV	Photovoltaic
PX	Power Exchange
RES	Renewable Energy Sources
RTM	Real-Time Market
RTO	Regional Transmission Organization
RUC	Reliability/Residual Unit Commitment
SCED/UC	Security Constrained Economic Dispatch/Unit Commitment
SEMO	Single Electricity Market Operator (Ireland and Northern Ireland)
SO	System Operator
SPP	Southwest Power Pool
SC	Screening Curves
TSO	Transmission System Operator
UC	Unit Commitment
US	United States (of America)
VER	Variable Energy Resources

1 Introduction

One of the key objectives for power system restructuring was the introduction of competition through the establishment of wholesale markets, starting from the generation level, whereby various generating companies could compete to meet a share of electricity demand. This transformation implied replacing centralized decision-making processes, creating multiple markets with different time scales.

Power market designs have been refined since their initial implementations, but they have not faced major changes in the needs of power systems until now. Currently, power systems are changing profoundly due to the necessary introduction of Renewable Energy Sources (RES), and as a result, there is an obvious need for significant market upgrades. The ongoing transition to a low-carbon power system involves large investments in RES capacity, of which, the main contributors will be Variable Energy Resources (VER) such as solar and wind power. The characteristic variability and uncertainty of VER production creates new challenges for the operation of power systems, and consequently, for power markets. For instance, the set of operational decisions (which should be aided by the market) required by VER are completely different to those of conventional resources.

Markets need to adapt, not only to facilitate VER participation, but also to enable the new energy resources that will accompany renewable sources in the energy transition, such as battery storage or aggregators (Ela et al., 2017). Furthermore, the needs of conventional resources will also change in a context with high shares of VER. The necessary market reforms will be broad and involve the complete market sequence, from long-term markets that are cleared years in advance, to very short-term balancing markets (namely in the European context) and so-called real-time markets in the United States.

In this complex puzzle, however, short-term markets represent the foundational piece on which other markets rely. Therefore, this document focuses on day-ahead and intraday markets. These are also the most critical markets for VER operational decisions, greatly impacted by VER production forecast uncertainty.

1.1 Context

Electricity short-term market design faces the difficult challenge of trying to combine the goal of creating competition tools, able to send sound economic signals to market participants, while at the same time guaranteeing the optimality and feasibility of the resulting dispatch, accounting for the technical complexities inherent to electric power systems' operation. This approach calls for a proper integration of the physical constraints in the market clearing processes, so the definition of roles and competencies of the System Operator (SO) is at the core of any short-term market design. In other words, the challenge is to define which decisions (and when) can be left to the market, and at which stage and how the SO should intervene on market results.

In certain jurisdictions, the role of the SO is clearly less predominant than in others, under the argument that the SO function should be limited to maximize the range of the market. This discussion of the separation of responsibilities between the market and the system operator has been central since the outset of market restructuring, see for instance Hogan (1995).

In this respect, the model implemented in US markets and the one in force in the majority of EU Member States[1] represent two different views on what the separation of responsibilities between the Market and the System Operators should be. Therefore, this document analyzes both of these contexts.

1.1.1 Markets in the United States

In the US, the integration of the physical constraints in the clearing process and the involvement of the Independent System Operator[2] (ISO) in the markets is probably the highest possible: the ISO gathers both activities, market and system operation, not only from the institutional perspective, but also from the operative standpoint, as energy trades are cleared jointly with security procedures. This is considered as necessary not only to reliably operate the system but also to guide market agents towards the optimal dispatch (taking into account technical and reliability constraints). This model is based

[1] With some exceptions, as for example Ireland until very recently or Poland.

[2] This document ignores the difference between ISO and RTO (Regional transmission organization). See FERC Orders 888 (FERC, 1996) and 2000 (FERC, 1999) for a rigorous definition.

on the concept of the bid-based, security-constrained economic dispatch (SCED)[3], where the requirements set by the ISO (e.g., different sorts of reserves) can even be co-optimized and priced along with energy.

Not all states implement electricity markets, although most of the US territory, and part of Canada (see Figure 1), follow the structure described, where an ISO is in charge of both power system operation and organized power markets. All ISOs in the US fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), with the exception of the Electric Reliability Council of Texas (ERCOT), which has resulted in a mostly uniform design for short-term markets across all ISOs. However, some design elements are still different from one ISO to another, so this document focuses on the features that are common to all of them, noting some punctual differences when necessary.

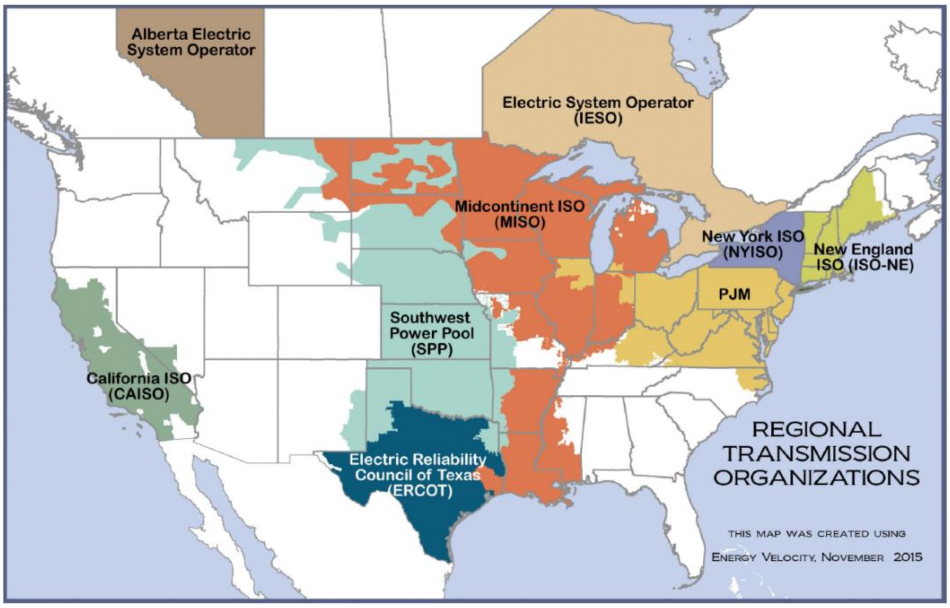


Figure 1. US regions with competitive electricity markets[4]

[3] The SCED is an optimization modeling tool that considers the physical constraints of generators (e.g. minimum and maximum output, ramp constraints), the transmission system configuration and constraints (with an explicit representation of grid losses and capacity), multi-part offers submitted by generators (e.g. start-up cost, no-load cost and variable cost) and demand bids. The output of this clearing algorithm is the optimal dispatch of each generator for each period of the following day, and a set of locational marginal prices (LMPs) resulting from the balance of supply and demand.

[4] Source: ferc.gov

1.1.2 Markets in the European Union

The model currently used in most European Member States, which we can call the EU Power Exchange (PX) approach, originally aimed at a simpler consideration of the physical reality, along with a major decoupling between the system operator responsibilities and the spot market functioning. The tasks of system operation are carried out by Transmission System Operators (TSO), while day-ahead and intraday markets are organized by Nominated Electricity Market Operators (NEMOs). The decoupling between markets and the physical system operation in the EU is such that in principle multiple NEMOs can operate in the same Member State, allowing competition between power exchanges. However (for obvious reasons), system operation responsibilities are well defined within each territory, without overlap of different TSOs.

This structure is quite consistent across Europe because the implementation of electricity markets has developed in parallel with European energy policies. Since the first electricity directive issued by the European Parliament and Council in 1996, the design of electricity markets has been coordinated across Member States, with the ultimate goal of implementing a common electricity market. The integration of EU markets is still incomplete, although relevant progress has been made on intraday markets, and especially, on day-ahead markets.

The integration of day-ahead markets aims at optimizing the use of cross-border capacity with a joint clearing algorithm developed under the Price Coupling of Regions (PCR) initiative. The algorithm is named EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm), and it is already in use to couple day-ahead markets in the core of Europe (see map in Figure 2), through the MRC (Multi-Regional Coupling) project. In parallel, the Four Markets Market Coupling (4M MC) project uses the same algorithm to couple the Czech, Slovak, Hungarian and Romanian markets, in preparation to ultimately join the MRC area. During 2018, Greece (which has direct current links to Italy) and Ireland (currently undergoing a market reform) are expected to join the MRC. At the same time, the latest European legislative package on energy (European Commission, 2016) showed an increased focus on improving energy market design.

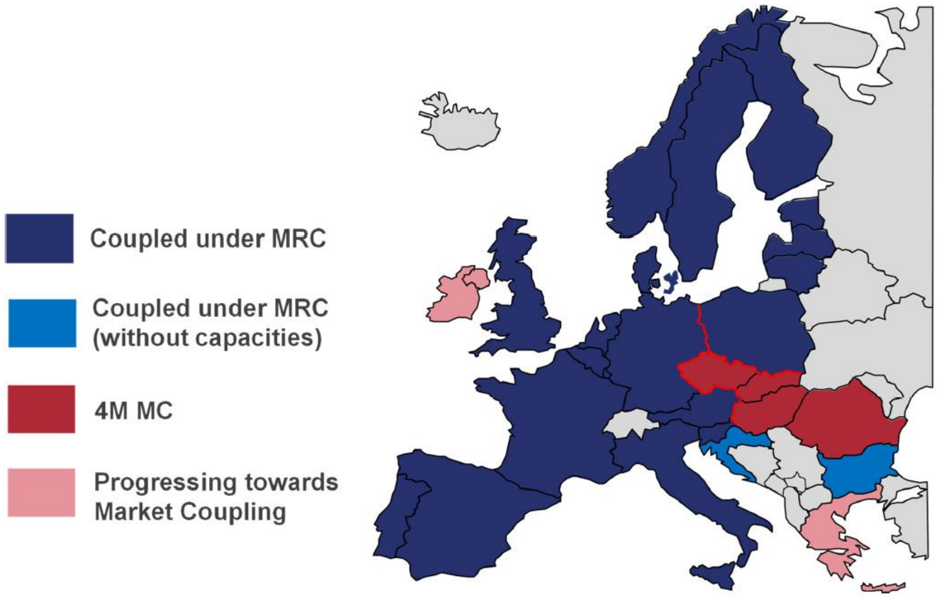


Figure 2. Status of European day-ahead markets coupling[5]

1.2 Short-term markets design elements

As pointed out above, electricity market design follows different approaches in the two contexts of interest. Therefore, a common framework for discussion is established around some general design elements. This analysis does not include all the elements that comprise short-term electricity market design. Instead, the selection of topics is based on which design elements are most relevant for VER integration (simultaneously in the US and EU context), and which are the issues where research gaps have been identified. This selection relies on previous research work and collaboration with other researchers[6].

The design elements analyzed are:

- Clearing and pricing rules: How organized markets schedule buying and selling transactions for market agents, and at what price. These transactions are the basis of the power system operation, and efficient pricing is critical to support dispatch decisions and drive future investment.
- Bidding formats: How market agents express their operational constraints and their willingness to engage in market transactions. This design element is influenced by the needs of different market agents, and the limitations of clearing algorithms.

[5] Source: ENTSO-E (2017)

[6] See Pérez-Arriaga et al. (2016) and Pérez-Arriaga et al. (2017)

- Intraday price signals: How agents are incentivized to participate efficiently in intraday scheduling decisions. In this timeframe, VER production forecasts are more accurate than in day-ahead markets, making it an increasingly relevant step in the operation of the system.

1.3 Research questions

As already introduced, the main objective of this research is to provide –based on a detailed analysis of a set of relevant design elements– design recommendations to improve electricity markets. The improvements proposed are motivated by the multiple challenges arising from the transition to low-carbon power systems, and focus on the US and EU context. This general objective translates into the following research questions:

- What factors should be taken into account in the design of clearing and pricing rules? What are the tradeoffs between the desired properties of different approaches, and how are they influenced by practical limitations?
- How does the penetration of VER influence the pricing rule discussion? What additional considerations does VER introduce in the design of pricing rules?
- How relevant are pricing rules in investment decisions? What pricing rules are more efficient, taking into account their long-term impact in investment decisions?
- What are the limitations of current bidding formats in a context where the operation of the power system becomes increasingly complex? How can bidding formats be improved?
- What is the role of intraday price signals in mitigating the impacts of VER production forecast uncertainty? How can intraday price signals be improved?

1.4 Document structure

This document is structured around the research questions presented above, where each chapter corresponds to one of the questions. Although each question refers to a single design element, when exploring these questions in detail it becomes evident that all the design elements are closely related. Therefore, although discussions are presented separately, initial chapters introduce some concepts before they are fully analyzed in a following chapter, and the latest chapters combine the knowledge built in the first parts of the document.

Chapter 2 analyzes pricing and clearing rules in the detail, while also providing the necessary background for the next chapters. Chapters 3 and 4 present different case examples to explore the questions of how VER influences the pricing rule discussion, and how this affects the long-term efficiency of power markets. Chapter 5 explores bidding formats, drawing from the previous analysis on clearing and pricing rule, which is an intimately related discussion. Chapter 6 extends the previous analysis, which focuses on day-ahead markets, to the intraday timeframe; and introduces the additional challenges of VER forecast uncertainty between day-ahead and intraday markets. Chapter 7 concludes, summarizes the market design recommendations, and proposes directions of future research[7].

References

Ela, E., Wang, C., Moorty, S., Ragsdale, K., O'Sullivan, J., Rothleder, M., Hobbs, B., Ela, B.E., Wang, C., Moorty, S., Ragsdale, K., Sullivan, J.O., 2017. Electricity Markets and Renewables. IEEE Power Energy Mag. 15, 70–82. doi:10.1109/MPE.2017.2730827

ENTSO-E, 2017. 3rd Report on the progress and potential problems with the implementation of Single Day-ahead and Intraday Coupling. August 2017. Available at: www.entsoe.eu

European Commission, 2016. Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity. November 2016. Available at http://ec.europa.eu/

FERC, 1996. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Order No. 888, FERC Stats. & Regs. 31,036, 24 April.

FERC, 1999. Regional Transmission Organizations. Order No. 2000, 89 FERC 61,285, 20 December.

Herrero, I., Rodilla, P., Batlle, C., 2014. Impact of day-ahead market pricing rules on generation capacity expansion. In Energy & the Economy, 37th IAEE International Conference, New York, USA, June 15-18, 2014. International Association for Energy Economics.

Herrero, I., Rodilla, P., Batlle, C., 2015. Electricity market-clearing prices and investment incentives: The role of pricing rules. Energy Economics 47, 42–51. doi:10.1016/j.eneco.2014.10.024

Herrero, I., Rodilla, P., Batlle, C., 2016. The Need for Intra-day Settlements in US Electricity Markets. In Energy: Expectations and Uncertainty, 39th IAEE International Conference, Bergen, Norway, Jun 19-22, 2016. International Association for Energy Economics.

Herrero, I., Rodilla, P., Batlle, C., 2018. Enhancing Intraday Price Signals in U.S. ISO Markets for a Better Integration of Variable Energy Resources. Energy Journal 39, No 3. doi:10.5547/01956574.39.3.iher

[7] During the development of this research, part of the work has been published in academic journals (Herrero et al., 2015; Veiga et al., 2015; Usera et al., 2017; Herrero et al., 2018) and conference proceedings (Herrero et al., 2014; Herrero et al., 2016), cited here for conciseness.

Hogan, W., 1995. A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy. The Electricity Journal, December 1995, pp. 26-37.

Pérez-Arriaga, I.J., Gómez, T., Batlle, C., Rodilla, P., Cossent, R., Herrero, I., Usera, I., Matropietro, P., Vinci, S., 2017. Adapting market design to high shares of variable renewable energy. International Renewable Energy Agency, Abu Dhabi. ISBN: 978-92-9260-025-9

Pérez-Arriaga, I.J., Knittel, C., Miller, R., Tabors, R., Bharaktumar, A., Birk, M., Burger, S., Chaves, J.P., Dueñas-Martínez., P., Herrero, I., Huntington, S., Jenkins, J., Luke, M., Rodilla, P., Tapia-Ahumada, K., Vergara, C., Xu, N., 2016. Utility of the Future. An MIT Energy Initiative response to an Industry in transition. ISBN: 978-0-692-80824-5. Available at www.energy.mit.edu/uof

Usera, I., Rodilla, P., Burger, S., Herrero, I., Batlle, C., 2017. The Regulatory Debate About Energy Storage Systems: State of the Art and Open Issues. IEEE Power Energy Mag. 15, 42–50. doi:10.1109/MPE.2017.2708859

Veiga, A., Rodilla, P., Herrero, I., Batlle, C., 2015. Intermittent RES-E, cycling and spot prices: The role of pricing rules. Electr. Power Syst. Res. 121, 134–144. doi:10.1016/j.epsr.2014.11.030

2 CLEARING AND PRICING RULES

Marginal pricing principles are well stablished in competitive power markets, however, the definition of marginal prices becomes challenging in the presence of non-convexities (as those derived from complex bidding formats). Therefore, the definition of market clearing rules and price computation methods is open to debate, as evidenced by the significant differences between market designs in Europe and the United States.
This chapter analyzes clearing and pricing rules from a both practical and academic point of view; it identifies advantages and disadvantages of different approaches, and extracts the desirable features of these alternatives. Based on said features, but also considering the different challenges found in both the EU and US context, this chapter provides recommendations to improve price formation in electricity markets. Following chapters extend these conclusions after a closer examination of other market design elements.

2.1 Introduction

Short-term auctions are at the very core of the wholesale electricity market. In these auctions market agents' bids and offers are matched with the "text-book" objective of determining not just who sells and who buys, but especially the market clearing prices for each time interval in the auction scope. These short-term electricity prices are instrumental, since they represent the reference for the longer-term power markets, i.e., for the system expansion.

The key economic theory principle at the basis of electricity market designs is marginal pricing. Under this principle, at each point in time, the market is cleared in a way that maximizes market welfare, and electricity is valued at the marginal cost of producing (or not consuming) an additional unit of energy. This setting ideally has two interesting properties:

- First, the marginal price supports the welfare maximizing solution, meaning accepted bids are sufficiently compensated and rejected bids are not profitable at the marginal price.
- Second, settling all transactions at the same price (uniform pricing) provides market agents with an efficient signal for bidding true opportunity costs and for optimal investment in the long-term (the main argument in favor of the energy-only market approach to ensure resource adequacy).

Roughly speaking, these good properties of marginal pricing only hold under the assumption that there are no lumpy decisions (Hogan & Ring, 2003), that is, they hold if there are no "lumpy costs" (e.g. start-up cost) or "lumpy constraints" (e.g. all-or-nothing commitment or minimum output constraints)[8]. Unfortunately, electricity markets present multiple and unavoidable lumpy decisions that condition clearing and pricing rules.

In the US ISO model, multi-part offers contain both lumpy costs and lumpy constraints, i.e., market agents express their start-up costs, and other non-convexities in their cost functions. In the EU Power Exchange context block bids and other complex conditions allow for an approximated representation of these costs and constraints. In this realistic and thus non-ideal context, it is mathematically impossible to find uniform prices that support the welfare maximizing solution (Scarf, 1994).

Furthermore, the discussion of price formation in non-convex electricity markets has gained increasing relevance in recent times, motivated by the ongoing transition to low-carbon power markets. As described in detail in Chapter 3, renewable energy sources increase the cycling operation of thermal generation resources, in other words, they increase the relevance of start-up costs and other inflexibilities in power markets. In addition, low-carbon market will require novel energy resources, which, as discussed in Chapter 5, will lead to increased use of complex bidding formats. Overall, the transition of the market calls for sophisticated clearing rules and precise price signals.

[8] More precisely, the problem is the presence of non-convexities in the optimization problem, i.e., the maximization of market welfare.

This challenge is analyzed in detail in the following sections. Section 2.2 identifies two primary clearing methods (uniform-price-based and optimal-dispatch-based) and illustrates the main differences using a simple example. Sections 2.3 and 2.4 discuss different pricing alternatives and analyzes their advantages and disadvantages. Section 2.5 provides a general classification of clearing and pricing rules and section 0 summarizes the main conclusions.

2.2 Clearing methods: Illustrative example

Practical implementations of marginal pricing include modifications aimed at trading-off between the abovementioned desirable properties (supporting the maximum welfare solution and uniform pricing). Not only different pricing rules are possible, the problem starts with the different ways in which the bid selection can be made (i.e., what bids to accept and reject). This section describes clearing methods based on two basic models:

- Optimal-dispatch-based clearing: The volumes accepted in the market are those of the welfare maximizing solution (optimal dispatch). Prices are usually based on the marginal cost, but in general the market cannot be cleared with an uniform price; that is, some agents may have to pay/receive an additional lump sum (uplift). This approach sacrifices uniform prices for short-term welfare maximization.
- Uniform price-based clearing: A uniform pricing rule constraint is imposed, that is, all transactions in a given period (e.g. an hour) are settled at the same price. This price constraint requires in general that the market solution deviates from the most efficient (welfare maximizing) dispatch.

Next, a simple example illustrates the fundamental characteristics in which these two general clearing rules differ, leaving other more profound implications for the following sections. Figure 3 sets a basic market-clearing problem; the green line represents a single demand bid, while each of the steps on the orange line represents a separate generation offer. Between the generation offers, there is an indivisible bid (dashed line); this bid can only be fully accepted or rejected. In the US context, this situation arises when a unit expresses a minimum output constraint equal to the capacity of the power plant. These units are known as block-loaded resources, and are usually fast-start gas turbines that only operate economically at full load. In the EU context, this type of bid corresponds to a block order with a minimum acceptance ratio equal to one (see Chapter 5 for additional details on bidding formats).

Due to this inflexibility, the market cannot clear at the intersection of the demand and supply curves. Furthermore, the indivisible bid can never be marginal (for it cannot marginally supply an additional MW of demand because of its inflexible nature). Note this is only an example of a non-convexity in the clearing problem, but many other possibilities exist.

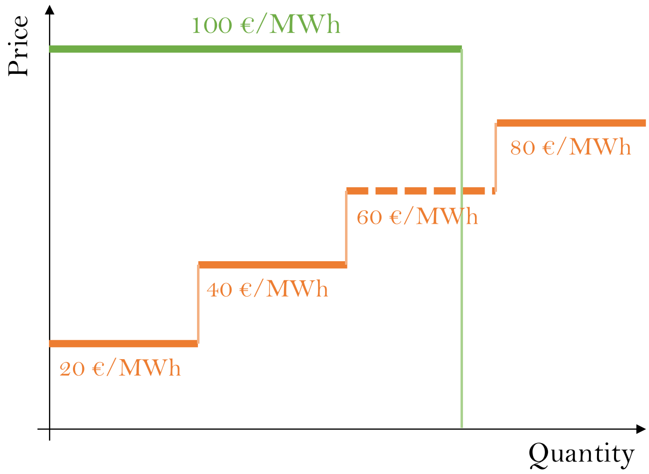


Figure 3. Market clearing problem with an indivisible bid

Using the dispatch-based clearing approach, the indivisible bid is accepted or rejected based on what solution maximizes market welfare (the area between supply and demand curves). In this case, the indivisible bid would be accepted, as shown on Figure 4. This reduces the production of a cheaper flexible plant, to make room for the indivisible bid.

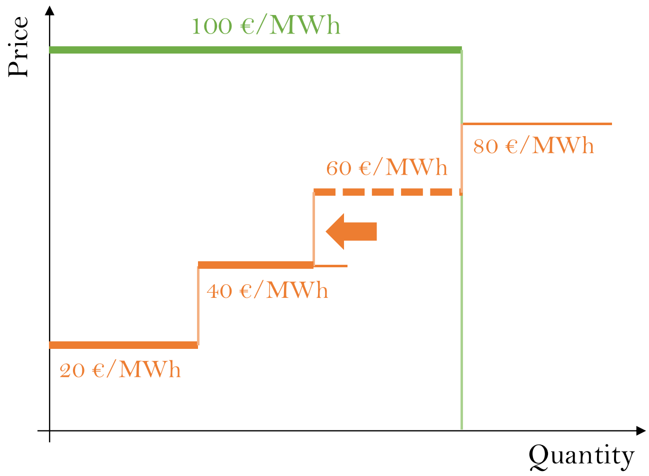


Figure 4. Optimal dispatch-based clearing solution

Note this approach decouples market clearing from pricing: the market welfare maximizing solution is independent from the market price, it only relates to accepted quantities. Given the market welfare maximizing solution, different pricing options are possible, imposing different allocations of the welfare. However, the most usual pricing approach is marginal cost pricing, which would set the price at 40 €/MWh. Indeed, the

40 €/MWh unit is the marginal unit, even if there is a more expensive unit dispatched, because the next marginal increment of load would be supplied by the 40 €/MWh unit. This price supports the dispatch solution for the units bidding 20 and 40 €/MWh, but the 60 €/MWh unit will not recover its productions costs. This is why the marginal cost pricing approach necessarily implies the use of uplift payments. The indivisible bid must receive an uplift payment, which is usually charged to demand. The allocation of the uplift charge is further discussed in the following sections, along with other pricing approaches.

The uniform price-based clearing approach also seeks to maximize market welfare, but under the condition that the price must be uniform, that is, all units receive the same income per unit of production, and no discriminatory uplift payments may exist. Given these constraints, the resulting dispatch is shown on Figure 5. With this clearing rule, accepting the indivisible bid would require setting the price at 60 €/MWh, but this is incompatible with the 40 €/MWh unit being marginal[9]. Therefore, the solution adopted in this case is to reject the indivisible bid completely, and accept the more expensive, but flexible, 80 €/MWh offer. In this case, the price is set at 80 €/MWh, which still follows marginal pricing principles, and allows for a uniform price, at the expense of short-term operational efficiency.

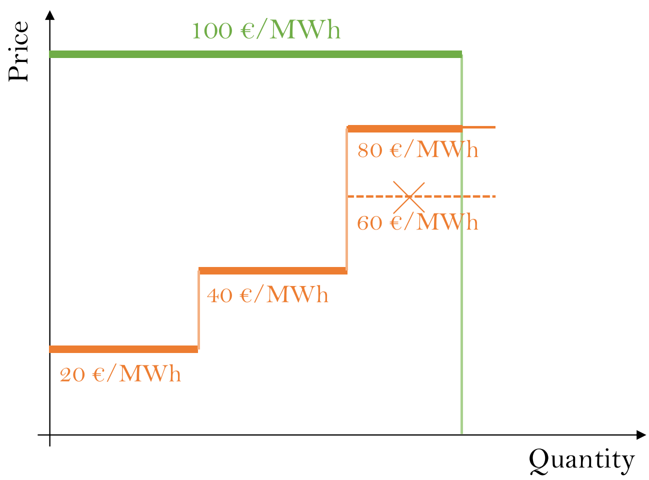


Figure 5: Uniform price-based clearing solution

[9] This is clarified later, when describing the criteria used in European power markets.

2.3 Clearing and pricing: Current practice

2.3.1 Markets in the United States

Electricity markets in the US follow the dispatch-based pricing approach; the ISO first calculates the optimal dispatch and then computes prices based on the marginal cost of the system, and uplifts to compensate generators incurring costs above the revenue earned through market prices. Uplift payments are also referred to as side-payments or make-whole payments.

As illustrated in the previous example, uplifts are unavoidable elements of the optimal dispatch-based pricing system required to support the welfare maximizing dispatch. The underlying problem with uplift payments is that they create a discriminatory pricing regime, where not all agents face the same prices, potentially creating misaligned incentives. This means price signals do not fully reflect operational costs, which can also have an effect in long-term investment decisions (Herrero et al., 2015).

Pricing in US markets, especially in the recent years, has deviated from pure marginal cost pricing in an attempt to reduce the weight of uplift, and to internalize as much as possible all operational cost into market prices. A notable example is the “hybrid pricing” approach first implemented by NYISO in 2001 (NYISO, 2001), and reviewed in 2017. The NYISO pricing approach allows block-loaded units (as the one in the previous example) to artificially become marginal in an ex-post run of the dispatch problem, where the inflexible bid is treated as flexible (as if it could be dispatched at any level between zero and its maximum power output). This way, block-loaded units can set prices, although NYISO only applies this method for a subset of fast-start units.

The more general term used for this practice is Integer Relaxation (IR) since it involves relaxing binary constraints in an ex-post pricing run of the dispatch problem, although the exact method is more nuanced and varies from one ISO to another. Indeed, most ISOs apply some type of IR, but they differ in which units can set prices, and whether they consider start-up and no-load cost in the pricing problem. In some cases (for instance, in the original NYISO hybrid pricing), only the minimum output constraint is relaxed in the pricing run, so only variable costs can impact prices; this practice is frequently called “EcoMin relaxation”.

In addition, “fast-start pricing” is also a common term in practice, because the relaxation often involves only fast-start units. Furthermore, some ISOs only apply IR in real-time markets, since block-loaded fast-start commitments are often made only in real time. As

Pope (2014) states, *"pricing approaches for fast-start block-loaded units are varied and incomplete within ISO-NE, PJM and the CAISO"*. Allowing fast-start units to set marginal prices can have positive effects, such as sending efficient signals to price-responsive load (Hogan, 2014), or incentives to fast-start units to improve their performance or bid their true cost (Harvey, 2014).

Fast-start block-loaded resources are certainly a very relevant part of the uplift problem, but this is not the only non-convexity causing price distortions. Start-up and no-load costs of all units can potentially cause uplift, both in the real-time and day-ahead markets. A more inclusive approach is applied in MISO (based on a simplified version of Convex-Hull pricing, see section 2.4.3); called approximated ELMP (extended locational marginal pricing). This approach is essentially an IR, but it is more comprehensive than NYISO's hybrid pricing. MISO includes start-up and no-load costs in pricing, and applies ELMP to all fast-start resources (not only to block-loaded ones). Indeed, MISO broadened the definition of fast-start resources to allow more peaking units to set prices (Potomac Economics, 2017).

Given the variety of pricing rules found in practice, this Thesis will refer to the general practice of relaxing some or all integer constraints, for some or all resources as Integer Relaxation. In any case, all the reviewed alternatives attempt to approach as much as possible a uniform pricing scheme. This represents the increasing importance of short-term market signals needed for efficient generation investment and the development of demand-side resources (Hogan, 2014).

2.3.2 Markets in Europe

European power exchanges share a single clearing algorithm for the day-ahead markets, while the integration of intraday markets is still incomplete. Therefore, the discussion of clearing and pricing rules presented here is focused on day-ahead markets, and the subject of intraday markets is discussed later in Chapter 6.

The clearing algorithm for day-ahead European electricity power exchanges is EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm), which uses the uniform price-based clearing approach.

As described in the previous example, the clearing logic is to maximize market welfare, with the following additional constraints:

- Uniform price: This entails that uniform market prices (without uplifts) must suffice to compensate all accepted bids.

- Preferential treatment of simple bids with respect to complex and block bids: simple bids cannot be paradoxically rejected. That is to say, if the market price is above the simple bid price, the bid has to be fully accepted.

In the European terminology, paradoxically rejected bids (PRB) are those rejected bids that would apparently be profitable if accepted. The European clearing rules allow the existence of PRBs, except for simple bids, which as described, have a preferential treatment. The uniform pricing principle is often rephrased as a restriction that does not allow the existence of paradoxically accepted bids (PAB). The concept of PABs can be likened to units that require uplift payments in the US context. Since PABs are not allowed in European markets, uplifts are consequently not allowed either.

As argued before, this approach leads to a sub-optimal market welfare, this is a matter of trade-offs and uniform pricing is considered in the European context as an objective worth the loss in short-term efficiency. Among the advantages of uniform pricing is that demand and generation interact in the market in equal terms, and it is not necessary to define rules to allocate uplift that would inevitably send inefficient signals.

Brief note: The case of Ireland

In the All Island Market of Ireland and Northern Ireland, the market operator (SEMO, or Single Electricity Market Operator), does not apply the European clearing and pricing algorithm. Since 2015, the SEMO has been working to integrate its markets with Europe, and in particular, to adopt the EUPHEMIA algorithm. As of 2018, SEMO and market participants are in a trial phase, although the final implementation date is still unclear.

The approach used in Ireland (so far) corresponds to the optimal-dispatch-clearing method, although the ex-post pricing algorithm is rather unique. Chapter 3 provides a complete description, but the dispatch determination is very similar to US markets, and the pricing is based on the marginal cost of the system, except that a uniform uplift is added. That is, instead of providing uplift payments only to some generation units, a price-adder (in essence, a uniform uplift) is computed so no generation unit needs any additional payment.

2.4 Discussion

Both clearing methods present advantages and disadvantages, however, the severity of the shortcomings depends on the actual characteristics of the market where the pricing rule is implemented. For instance, both clearing approaches would provide perfect and identical incentives without non-convexities. In practice, real markets present numerous non-convexities, and the discussion on how to improve clearing rules is increasingly active in both the US and EU context. This section reviews the discussions to date, including a review of academic contributions to the topic.

2.4.1 Discussion in the US context

The main concern in US markets with respect to pricing rules is an excessive amount of uplift payments. Uplifts can occur for many reasons, but the three primary ones in ISOs markets are (FERC, 2014b):

- Some operating costs (start-up, no-load costs) are not reflected in marginal prices.
- Inflexible resources, such as block loaded units, cannot set marginal prices[10].
- Un-modeled system constraints that make re-dispatches necessary.

Uplifts are necessary to guarantee revenue-adequacy of the optimal dispatch-based clearing approach, and as already described, completely removing uplift would bring along other inefficiencies. Therefore, the real concern is not the uplift, but an excessive amount of it, as stated in FERC (2014c):

> *"Use of uplift payments can undermine the market's ability to send actionable price signals. Sustained patterns of specific resources receiving a large proportion of uplift payments over long periods of time raise additional concerns that those resources are providing a service that should be priced in the market or opened to competition".*

Pope (2014) adds to this statement:

> *"Uplift is a symptom rather than a cause of price formation problems, though, and efforts to improve pricing should focus on correcting the causes".*

An additional problem with uplift is the allocation of its cost, which is somewhat arbitrary. The current practice, taking advantage of demand-side inelasticity, is to socialize uplift charges in an ex-post pro-rata allocation. This approach can hinder active demand participation in electricity markets, and the uplift allocation may need to be incorporated in the market clearing process to also guarantee revenue-adequacy for the demand side.

[10] This corresponds to the example in section 2.2. This is a particularly evident price distortion, although the underlying problem is more general and applied to any non-convexity in the clearing problem.

The price formation discussion has been especially active in the recent years, leading to a proposal from the FERC (2016) to improve fast-start pricing. The proposal is similar to the previously mentioned Integer Relaxation approach, applying the following principles:

- Apply fast-start pricing to any resource committed by the RTO/ISO that is able to start up within ten minutes, has a minimum run time of one hour or less, and that submits economic energy offers to the market.
- Incorporate commitment costs, i.e., start-up and no-load costs, of fast-start resources in energy and operating reserve prices.
- Modify fast-start pricing to relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero to the economic maximum operating limit for the purpose of calculating prices.
- If the RTO/ISO allows offline fast-start resources to set prices for addressing certain system needs, the resource must be feasible and economic.
- Incorporate fast-start pricing in both the day-ahead and real-time markets.

However, the proposal faced opposition from many ISOs, who argued that pricing rules should be tailored to each context. Therefore, the Commission withdrew the Rule (FERC, 2017), and instead initiated more targeted procedures for each market. At that time (arguably more ambitious) reforms to improve price formation were well underway in ISO-NE and MISO (with the approval of the FERC), and CAISO was involved in other initiatives of higher priority. Therefore, only PJM, NYISO and SPP were required to apply these changes to their fast-start pricing logic.

2.4.2 Discussion in the EU context

European Member States have successfully integrated their day-ahead electricity markets in a single coordinated clearing mechanism. Now that the integration is relatively complete, more attention is paid to improving the clearing algorithm. Probably, the most relevant concern nowadays is the existence of PRBs. As previously described, PRBs are unavoidable under a uniform price-based clearing; however, in certain cases bids may be incorrectly rejected due to the complexities of the algorithm. As pointed out by the Market Parties Platform (MPP) in the European Stakeholder Committee of the Price Coupling of Regions (2015):

> *"There may exist false PRBs: rejected in-the-money blocks that could have been accepted and result in a better (higher welfare) solution. MPP asks for more transparency on optimality, to prove the absence of false PRBs"*

The reason behind this matter is that, mathematically, the clearing problem is a non-linear and non-convex problem, for which it is difficult to prove the optimality of a solution, or to take a quantitative measure of the quality of a solution. This may hinder the confidence of market participants, together with a lack of clarity in the public documentation of the clearing algorithm (EPEX SPOT et al., 2016). The joint response of ACER and CEER (2015) to the European Commission's Consultation on a new Energy Market Design claims that: *"We would particularly like to see clearer rules and greater transparency around the market coupling algorithm (EUPHEMIA)"*.

The uniform price-based clearing rule relies on marginal pricing, even if the dispatch solution is not fully welfare maximizing, this means that in the EU context, inflexible bids cannot set market prices. As described in (Eirgrid et al., 2015):

> *"The effect of defining an order as a block is that the order cannot then be a full price maker. Rather, block orders may impose a bound on the range of prices possible while the price being set would still need to come from the simple order or complex order curves. This is because the decision to execute the order is an integer decision (i.e. the order is executed or not executed) and the decision on whether to accept a block occurs before the price determination sub-problem. The bound created by the last accepted block order would function to affect the price (by limiting possible values) but could not directly set this price."*
>
> *"This was discussed with the PCR ALWG[11] representative, APX, who confirmed that without the blocks setting the price, the price could only be set by other price makers, i.e. simple orders or complex orders, or the price indeterminacy rules of EUPHEMIA"*

What this means is that in a scenario where most bids are inflexible, or otherwise non-convex (as described in Chapter 5), EUPHEMIA can fall into computational problems, and lead to market prices that do not accurately reflect marginal costs. A large amount of non-convex bids increases the computational complexity of the clearing problem, which by coupling clearing and pricing through the uniform price rule, is inevitably a

[11] Price Coupling of Regions Algorithm Working Group

problem harder to solve than US approach where the economic dispatch problem is decoupled from pricing. Current efforts focus on improving the computational performance of EUPHEMIA, however, this is rather a temporal fix, and more thorough solutions may be needed to face the complexity issue.

2.4.3 Academic discussion

Previous sections described clearing and pricing approaches used in practice, however, the topic of finding prices in markets with non-convexities (Scarf, 1994) has been extensively discussed in the literature, and numerous methods have been proposed, still subject to intense debate. Given that excellent and up to date literature reviews can be found, see for example (Fuller and Çelebi, 2017) or (Liberopoulos and Andrianesis, 2016), this section will not provide a comprehensive review of academic contributions, but will instead present the general principles and recommendations that can be derived from them.

Revenue adequacy

A seemingly universal principle is revenue adequacy; this is, ensuring non-negative profits for market participants. All of the pricing approaches described earlier respect this principle, either by providing uplift payments to compensate operation costs not recovered from market prices, or using a suboptimal clearing solution where only profitable bids are accepted. However, some markets do not explicitly enforce revenue adequacy for the demand side of the market. In US markets, uplift charges are allocated to consumers, which are not price responsive, but this pricing approach could present new challenges if a relevant part of demand becomes an active market participant. Academic contributions focus on reducing uplift payments, for example, Hogan and Ring, 2003 use the welfare maximizing dispatch, and then computes prices that minimize uplift payments. For the illustrative example used before, this would result in the dispatch and price shown in Figure 6, the welfare maximizing solution is still used, but the price is now 60 €/MWh. The resulting price is not marginal (40 €/MWh was the marginal price), but ensures zero uplift payments since the 60 €/MWh unit recovers its full cost from the market price.

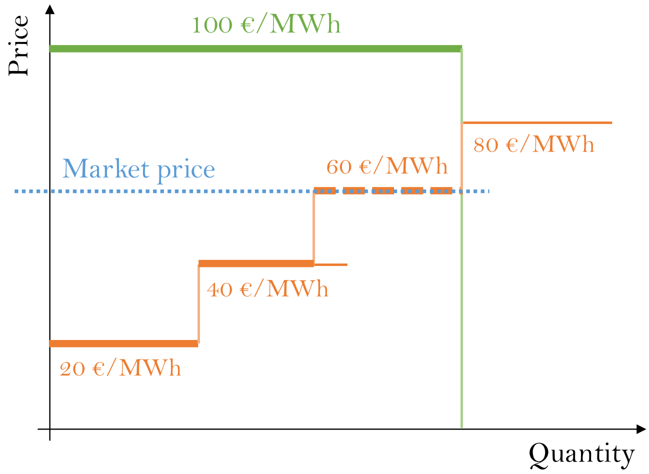


Figure 6. Minimum-uplift price applied to optimal dispatch

Note this is only a very simple example, and in general, minimizing uplift does not allow for zero uplift in total. (Gribik et al., 2007) proposed a method to find uplift-minimizing prices (in a single-period problem) known as Convex Hull (CH), this approach was generalized in (Schiro et al., 2015), proving CH pricing actually minimizes total side payments (including lost opportunity costs, see next section on lost opportunity costs). However, CH pricing is computationally complex and rather unintuitive, which is why Integer Relaxation (which is simpler, but equivalent in some cases), has been applied instead in practice. As stated by Schiro el al.:

> *"ISO New England believes that Convex Hull Pricing should be studied more rigorously to gain a better understanding of its short- and long-term consequences. It would be premature to suggest that Convex Hull Pricing is in any way preferred over common pricing methods at this time. Simpler pricing schemes may be more practical and transparent while achieving similar benefits."*

All these pricing schemes roughly aim at minimizing uplift, while keeping the welfare maximizing clearing approach. However, other academic proposals allow (as in European markets) a suboptimal welfare in exchange for lower (for example, Minimum Total Opportunity Cost pricing in Fuller and Çelebi, 2017) or zero uplift (as in Primal-Dual pricing, proposed by Ruiz et al., 2012).

Opportunity costs

Some authors point out that revenue adequacy is not sufficient to guarantee a short-term market equilibrium. Market participants could still have an incentive to deviate from the market solution if they face opportunity costs. These are cases where a generator may receive sufficient revenue to avoid losses, but for given market prices, could still increase its profit modifying its dispatch. Resorting back to the previous example, the 40 €/MWh unit is not dispatched at full capacity, even though the price is above its bid. Therefore, this unit has an opportunity cost, or in other words, the market price is not enough of an incentive for this unit to follow the market solution. An option is of course to compensate for these opportunity costs in the same way uplift costs are paid. Another line of thought is that these opportunity costs should not be accounted for, since they are not compensated in real markets[12].

This principle is relevant for the European discussion about PRBs. The EUPHEMIA algorithm does not produce any opportunity costs for simple orders, since they must always be completely accepted if in the money. However, paradoxically rejected block orders face an opportunity cost, since from the generator perspective, they could be profitable if accepted at given market prices. Still, PRBs do not receive any compensation because generators do not have a real incentive to deviate from the market solution, given that the deviation energy would not be settled at the market price, but at a different intraday or balancing market price.

In US markets where fast-start pricing is applied, opportunity costs arise for infra-marginal units dispatched below their capacity. Again, this cost is not compensated, although for a slightly different reason. Fast-start pricing is applied in an ex-post calculation, following the real-time market, so when units are dispatched, prices are not known yet. Therefore, there is no incentive to deviate from the optimal dispatch, besides, deviations could also incur in penalties. However, some authors argue that opportunity costs should be compensated/minimized if fast-start pricing is used, because units that consistently face opportunity costs could be better off by self-dispatching. In US markets, units can self-dispatch, and communicate their dispatch decision to the ISO; in this case, the unit becomes a price-taker. To optimally self-dispatch, a generator requires an accurate forecast of electricity prices, so unless the expectation of opportunity costs is quite certain, it may be preferable to participate as a price-maker.

Cost allocation

Most academic contributions analyze the pricing problem in a day-ahead market setting, and ignore the uplift allocation problem. However, especially in the recent years, as interest in demand participation in the market has grown, uplift allocation has become

[12] Other opportunity costs, such as those arising from operating reserve provision, may be compensated for.

an integral part of the discussion. O'Neill et al. (2016) propose a pricing method for the US context, which allocates uplift payments while guaranteeing revenue adequacy for both supply and demand bids. This topic is especially relevant in the US context (where there are uplift costs), although some authors focused on the European context: Van Vyve (2011) propose an optimal-dispatch clearing approach, which would imply some uplift costs, and considers both generation and demand revenue adequacy constraints in the allocation of uplift.

Indeed, O'Neill and Van Vyve proposals are similar in that the price determination problem also determines uplift allocation, imposing revenue adequacy constraints. This is a fresh perspective that extends revenue adequacy constraints to demand bids, therefore allowing uplift charges to be allocated to generators if needed.

2.5 Clearing and pricing classification

Previous sections introduced only a sample of clearing and pricing rules that can be found in practice and in academic proposals. Most of the alternatives start with an optimal dispatch or welfare maximizing clearing, and then follow different procedures to compute prices. The academic contributions highlighted here focus on the price computation step, since the formulation of the welfare maximizing problem as a MILP (Mixed Integer Linear Problem) is quite standard in US markets and well-stablished in the literature. On the other hand, proposals that deviate from the optimal dispatch to allow uniform (or almost uniform) prices present more novelties on the formulation of the clearing problem.

Clearly, it is not possible to derive a straightforward but complete classification that captures all the nuances of the multiple clearing and pricing approaches. However, a simple classification is useful and necessary. The following classification (see Table i) does not attempt to be strict or comprehensive, instead, its aim is to facilitate discussions in the next chapters, while following as much as possible the terminology already stablished in the literature.

Specially, the definition of certain pricing rules as "linear" is intentionally loose, however, this group is necessary to differentiate marginal cost pricing from those approaches that at least tend to or attempt to minimize the difference with linear prices. These are pricing rules that at least partly reflect non-convex cost in prices, and therefore have similar implications in what their long-term incentive effect might be, which is the key question in Chapter 4.

Table i: Classification of clearing and pricing rules

Clearing		Pricing: Non-linear	Pricing: Linear	Pricing: Strictly linear
Clearing	Optimal dispatch	Marginal cost pricing	Minimum uplift Convex Hull / ELMP Integer Relaxation Van Vyve model Dual Pricing	Ireland (SEMO)
	Uniform price			Primal-Dual Min. Total Opportunity Cost EUPHEMIA

The EUPHEMIA algorithm is included here as a clearing and pricing approach, although it should be regarded as a particular implementation that follows the rules for the acceptance of market orders defined by power exchanges and European regulators. Indeed, several authors propose different approaches to solve the clearing problem under EU rules, for example, Martin et al. (2014) formulates the clearing problem as a MPEC (Mathematical Problem with Equilibrium Constraints) with binary variables, and solves the problem by decomposing it into a master MIQP (Mixed-Integer Quadratic Problem) and linear subproblems. This approach is similar to what can be inferred from the public description of the EUPHEMIA algorithm (EPEX SPOT et al., 2016). Madani and Van Vyve (2015) propose a reformulation of the problem that yields a MILP which allows to solve the problem with standard solvers without the need for decompositions or heuristics. This formulation however does not allow for piecewise linear orders (one of the bidding formats available in Europe, as reviewed in Chapter 5), which would still require solving a quadratic problem.

2.6 Conclusions

The discussion of clearing and pricing rules has been especially active in recent years, as markets increasingly rely on complex bidding formats, and the effect of non-convexities in market prices is intensified by renewable energy penetration. In this context, inefficiencies in price formation are becoming more apparent and clearing and pricing rules should be reexamined in both US and EU markets.

In Europe, the increasing complexity of the uniform pricing approach may put into question its ability to provide a transparent market, and its computational feasibility. European markets could benefit from a shift towards an optimal-dispatch approach, especially as more non-convexities are incorporated into market orders, which will further degrade the welfare obtained by the uniform price-based clearing rule. However, the European design has some positive features that should not be abandoned. The uniform pricing approach implicitly guarantees revenue adequacy for all market participants, including demand; this should facilitate future participation of demand resources. Therefore, any alternative pricing approach considered should include a non-discriminatory allocation of uplift and/or opportunity costs.

In this regard, the lessons learned in the US context could be relevant as well in Europe. Options based on the optimal-dispatch and an ex-post price computation seem the most adequate. First, it is difficult to justify any clearing approach that provides a suboptimal market welfare. Decoupling clearing from pricing also decreases the computational burden, and facilitates the understanding and verification of market results. The ex-post price computation however, is where more open questions remain, the limitations of traditional marginal cost pricing are well known, but no consensual alternative exists. Some of the most promising alternatives in the academic context may be impractical in reality due to their computational complexity and difficult economic interpretation. Indeed, the simpler alternatives based on a relaxed version of the unit commitment problem are gaining traction in US markets, although regulators are still very careful in their implementation targets. However, this progress has facilitated relevant improvements in practice. Given that no single pricing approach will combine all the desirable properties, future efforts should focus on understanding the existing tradeoffs, to implement the best solution for each context.

2.6.1 Next chapters

Chapter 3 highlights the increasing relevance of the pricing rules discussion. It shows that variable energy resources (such as wind and solar) change the operation regime of thermal generating units. In general, larger shares of renewable resources lead to increased cycling and more frequent start-up/shutdown cycles for thermal units. These changes have a widely different impact on market prices depending on what pricing rule is implemented. The results suggest that, while linear and non-linear pricing rules may have resulted in relatively similar prices before, this is no longer the case after renewable generation begins to dominate the operation of power systems, as it is often the case today.

Chapter 4 uses a numerical case example to assess the long-term impact of different pricing rules. Linear and non-linear pricing rules are compared by looking at the set of investment decisions that would take place in a competitive market where one or the other rule is implemented. The results show that a non-linear (traditional marginal cost pricing) pricing rule does not provide efficient investment signals, leading investors towards suboptimal investment decisions that, in the long term, increase supply costs and reduce market welfare. On the other hand, linear pricing rules, while still suboptimal, provide more efficient signals and result in an almost optimal market welfare in the long term.

Chapter 5 elaborates on the issue of bidding formats, which is the reason why non-convexities are introduced in the clearing problem in the first place. The conclusions of this chapter confirm the increasing need for complex bidding formats, in both the European and US context. In particular, it raises additional questions on the computational tractability of uniform-price-based clearing approaches, and supports again the implementation of linear pricing rules.

Chapter 6 introduces the notion of intraday price signals. While previous chapters examine the pricing rule discussion in a day-ahead market context, this chapter considers the potential sequence of markets in the intraday timeframe. This leads to additional considerations when designing clearing and pricing rules, especially for the allocation of uplift.

References

ACER-CEER, 2015. Joint ACER-CEER response to the European Commission's Consultation on a new Energy Market Design. October 07, 2015.

David Fuller, J., Çelebi, E., 2017. Alternative models for markets with nonconvexities. Eur. J. Oper. Res. 261, 436–449. doi:10.1016/j.ejor.2017.02.032

Eirgrid, SEMO, APX Power & SONI, 2015. I-SEM trialling of EUPHEMIA: initial phase report. September 2015, available at www.sem-o.com

EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, TGE, 2016. EUPHEMIA Public Description, PCR Market Coupling Algorithm. Version 1.5, December 2016.

European Stakeholder Committee of the Price Coupling of Regions, 2015. Euphemia Performance, September 2015.

FERC, 2014a. Operator-Initiated Commitments in RTO and ISO markets, Staff Analysis, Docket No. AD14-14-000, December 2014.

FERC, 2014b. Uplift in RTO and ISO markets, Staff Analysis, Docket No. AD14-14-000, August 2014.

FERC, 2014c. Notice of proceeding regarding the Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators. Docket No. AD14-14-000. June 19, 2014.

FERC, 2016. Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Notice of Proposed Rulemaking. Docket No. RM17-3-000, 157 FERC ¶ 61,213. December 15, 2016.

FERC, 2017. Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Withdrawal of Notice of Proposed Rulemaking and Termination of Rulemaking Proceeding. Docket No. RM17-3-000, 161 FERC ¶ 61,293. December 21, 2017.

Gribik, P.R., Hogan, W.W., Pope, S.L., 2007. Market-Clearing Electricity Prices and Energy Uplift. Harvard University.

Harvey, S., 2014. Is the California ISO Becoming an Uplift Market? Pricing, Uplift and Commitment (presentation). FTI Consulting. Available at: www.caiso.com

Herrero, I., Rodilla, P., Batlle, C., 2015. Electricity market-clearing prices and investment incentives: The role of pricing rules. Energy Economics 47, 42–51. doi:10.1016/j.eneco.2014.10.024

Hogan, W., 2014. Electricity Market Design and Efficient Pricing: Applications for New England and Beyond, June 24, 2014

Hogan, W., Ring, B.J., 2003. On minimum-uplift pricing for electricity markets. Electricity Policy Group.

Liberopoulos, G., Andrianesis, P., 2016. Critical Review of Pricing Schemes in Markets with Non-Convex Costs. Oper. Res. doi:10.1287/opre.2015.1451

Madani, M., Van Vyve, M., 2015. Computationally efficient MIP formulation and algorithms for European day-ahead electricity market auctions. European Journal of Operational Research, 242(2), 580–593. doi:10.1016/j.ejor.2014.09.060

Martin, A., Müller, J. C., Pokutta, S., 2014. Strict linear prices in non-convex European day-ahead electricity markets. Optimization Methods and Software, 29(1), 189–221. doi:10.1080/10556788.2013.823544

NYISO, 2001. New York Independent System operator, INC's Motion for Permission to implement Hybrid Fixed Block Generation Pricing Rule. March 20, 2001.

O'Neill, R., Castillo, A., Eldridge, B., Hytowitz, R.B., 2016. Dual Pricing Algorithm in ISO Markets. IEEE Trans. Power Syst. 8950, 1–1. doi:10.1109/TPWRS.2016.2614891

Pope, S.L., 2014. Price formation in ISOs and RTOs, principles and improvements. October 2014. FTI Consulting. Available at www.epsa.org

Potomac Economics, 2017. 2016 State of the Market report for the MISO Electricity Markets. June 2017. Available at: www.potomaceconomics.com

Ruiz, C., Conejo, A.J., Gabriel, S.A., 2012. Pricing non-convexities in an electricity pool. IEEE Trans. Power Syst. 27, 1334–1342. doi:10.1109/TPWRS.2012.2184562

Scarf, H.E., 1994. The allocation of resources in the presence of indivisibilities. The Journal of Economic Perspectives 111–128.

Schiro, D.A.D.A., Zheng, T., Zhao, F., Litvinov, E., 2015. Convex Hull Pricing in Electricity Markets: Formulation, Analysis, and Implementation Challenges. IEEE Trans. Power Syst. PP, 1–8. doi:10.1109/TPWRS.2015.2486380

Van Vyve, M., 2011. Linear prices for non-convex electricity markets: models and algorithms. CORE Discussion Paper 2011/50.

3 THE ROLE OF PRICING RULES IN LOW-CARBON ELECTRICITY MARKETS

Increased penetration of Variable Energy Resources (VER) in power systems has several impacts on power prices. VER penetration affects the operation of thermal power plants, which is one of the main factors in price dynamics. In a system with significant VER production, system operation becomes more constrained, and the inflexibilities of thermal plants become ever more relevant. In this context, both electricity prices and system operation –usually dominated by generation variable costs–, increasingly depend on other cost components, such as start-up and O&M costs.

These factors make for a complex relationship between VER penetration and electricity prices, which further depends on the pricing rule implemented. This chapter uses a realistic case study to study this question. The study makes a special emphasis on properly modeling the impact of thermal power plants cycling on O&M and start-up costs, and how they are internalized in power prices depending on the pricing rule. Traditional marginal cost pricing is compared with the pricing rule implemented in Ireland, as an approximation of a uniform pricing rule.

3.1 Introduction

The penetration of Variable Energy Resources (VER) significantly changes the way electric power systems are operated, see for instance Pérez-Arriaga and Batlle (2012). These changes in short-term operation have a direct impact on production costs. The two major short- and medium-term effects are the following:

- VER, which have zero variable cost, tend to displace the most expensive variable cost units[13] (such as fossil-fuel electricity production).
- VER increase the cyclical operating modes of thermal plants that occur in response to dispatch requirements: on/off operation, low-load operation and load following, see e.g. Troy et al. (2010). One of the major consequences is that as the number of starts increases so does the indirect costs of each individual start, see Rodilla et al. (2014).

Note that the impacts on costs derived from the previous two changes in operation go in opposite directions. While the first decreases overall short-term operation costs, the second leads to an unprecedented increase in the weight of one of the components of conventional thermal plants' cost structure. In a market context, these previous changes in operation also imply changes in short-term price dynamics and market remuneration.

As a consequence of the replacement of fossil-fuel plants with zero variable cost VER energy, average operational costs decrease, and prices decrease as well in average. This is the so-called merit order effect. On the other hand, prices could increase intermittently, when generating units' remuneration has to be increased to allow recovery of increased cycling costs (and particularly the cost of each start). Although increased cycling costs can have a small impact on average system costs, this dynamic changes the usual relation between average costs and prices.

The relevance of the previous two effects on both short-term prices and the resulting remuneration depends on the characteristics of the system, especially on the generation mix. As noted in Pérez-Arriaga and Batlle (2012), the merit order effect is less significant when the addition of VER does not significantly change the marginal technology setting the price in the system. For example, this could be the case in some European power systems, due to the large share of combined cycle gas turbines (CCGT) which are frequently setting marginal prices. The impact of start-up costs on market prices, however, depends on which pricing rule is implemented; this is why two different pricing rules are compared in this case study.

[13] Another effect is related to the need for flexibility. In order to cope with the abrupt production profiles of VER, it may be economical to commit more flexible (and in some cases more expensive) units that would not be committed otherwise.

3.2 Impact of start-up costs and non-convexities

3.2.1 Cycling needs

A large deployment of renewable generation implies a significant change in the scheduling regime of other generating facilities. For instance, a larger number of conventional thermal units might be forced to either decrease the production to the minimum stable load for a larger number of hours and usually to start and shut down more frequently. This effect is more acute in thermal-dominated systems, with lower flexibility, and thus conversely less relevant in those in which the share of hydro reservoirs is significant.

This change in the operating regime of the thermal plants translates into a change in costs. Thermal plants operation costs depend on three main factors:

- Fuel start-up costs (fuel needed to raise the boiler to its minimum operating temperature prior to producing electricity).
- Energy production costs as a function of the incremental heat rate curve (that is, a curve taking into account the efficiency-loss costs due to suboptimal operation regime). Production costs (fuel consumption) are higher (per unit generated) at low load operation than at close-to-full capacity. When the plant operates below the optimum point, the plant efficiency is lower and therefore the production cost per MWh produced is larger. The number of hours producing at minimum stable load is likely to increase in the presence of VER and therefore the energy production cost will be higher.
- O&M costs: cycling the thermal plants accelerates component wear and tear, resulting in an increase in failure rates, longer maintenance and inspection periods and higher consumption of spares and replacement components (Rodilla et al., 2014). For some technologies, maintenance procedures are structured in Long-Term Service Agreements (LTSA). In the particular case of gas-fired technologies, see for example Sundheim (2001), these LTSA contracts include both the criteria to carry out a major maintenance inspection and the cost of this inspection, usually depending on some thresholds representing the accumulated operation since last maintenance. These threshold conditions, typically expressed as a function of the firing hours and starts, define the Maintenance Interval Function (in the following MIF). The shape of the MIF for gas turbines varies between manufacturers. Figure 7 shows some examples of MIF. Some manufacturers base their maintenance requirements on

separate counts of machine starts and operation hours. The maintenance interval is determined by the threshold criteria limit that is reached first. The MIF in this case takes the rectangular shape shown in Figure 7 (option A). Other manufacturers assign to each start cycle an Equivalent number of Operating firing Hours (EOH). The total amount of EOHs a particular plant has operated up to a certain point thus depends on both the number of firing hours and the number of starts. The inspection is carried out when a predefined number of EOHs is reached (option B). More generally, the MIF could be defined by any functional form combining the number of starts and the number of firing hours (option C).

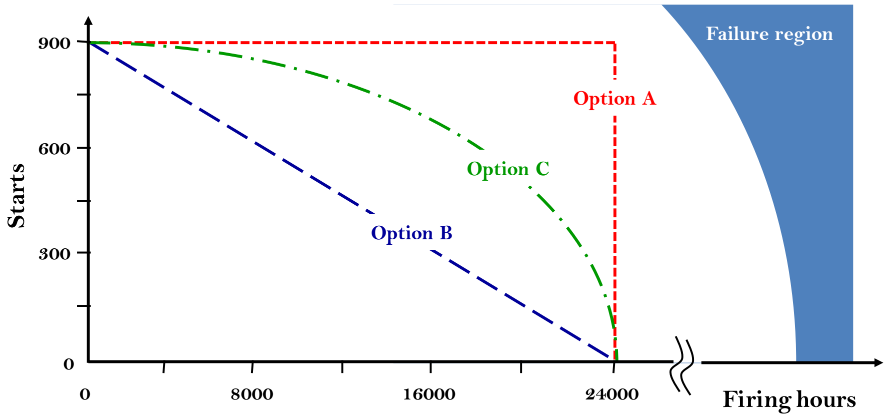


Figure 7. Baseline functions for maintenance interval[14]

In general, the larger the number of starts, the lower the amount of firing hours the unit can operate before a major maintenance is triggered[15]. This is because starting up more frequently accelerates the wear of the turbine as well as other elements of the plant.

3.2.2 The role of pricing rules

As just reviewed, starts are responsible for shortening the maintenance periods and consequently for increasing maintenance expenses. To account for this effect, it seems reasonable for generation units to include a cost adder in their offers (on top of the fuel-only start-up cost). In fact, this start-up cost adder due to O&M is an accepted additional cost in some markets as for instance in PJM (2012) or ERCOT (2011). This issue has also been discussed in CAISO (McNamara, 2011). Since in a well-functioning market costs are supposed to be recovered through market income, the increase in start-up costs should have an impact on market prices. However, as largely discussed in Chapter 2,

[14] Based on (PPA, 2002) and (Balevic et al., 2010)

[15] With the sole exception of certain production regimes in the case of the maintenance function denoted here as Option A.

different market pricing rules internalize lumpy operation costs in different ways, so the final weight of the change depends on the particular pricing rule implemented.

Our aim is thus to assess and illustrate the potential impact of different pricing mechanisms in the presence of large amounts of VER. Therefore, the traditional marginal cost pricing approach (representing the optimal-dispatch-based clearing approach discussed in the previous chapter) is compared with the pricing rule used in Ireland (as a proxy to uniform price-based clearing).

The Irish market operator, on the basis of multi-part bids (start-up costs, no-load costs, etc.), first calculates the unit commitment and dispatch that maximizes market welfare and computes the preliminary prices as the dual variables associated to the generation-demand balance constraint (SEMO, 2014). These prices are exactly the same prices in a marginal-cost pricing context. Then, since these prices do not guarantee total cost recovery for all the units in the system, an ex-post optimization is used to obtain the (hourly) uniform uplifts to be added on top of the previously calculated prices. This second optimization aims to fulfil full operating cost recovery while at the same time seeking two additional objectives: (i) avoid when possible the concentration of very high uplifts on only a few hours and (ii) minimize demand payments. The mathematical formulation is detailed in Annex 3.C.

The two specific pricing rules selected are only a representative example of a linear and a non-linear approach, although, as noted in previous chapters, many alternative pricing methods are possible. Although, strictly speaking, the case example applies only to these two pricing rules, some of the questions answered can be more general. For instance, one of the main questions is how relevant this difference in the computation of prices and uplift charges can be, or in other words, how relevant the choice of the pricing rule is. As a way of illustration, the next figure shows the weight of the uniform uplifts in a sample day in the Irish market. In a marginal cost (non-linear) pricing context, an infra-marginal base-load unit would receive only the hourly shadow prices depicted in red, while using the Irish (linear) pricing rule, it would also receive the hourly uplift components. It is clear from the example that the difference can become substantial.

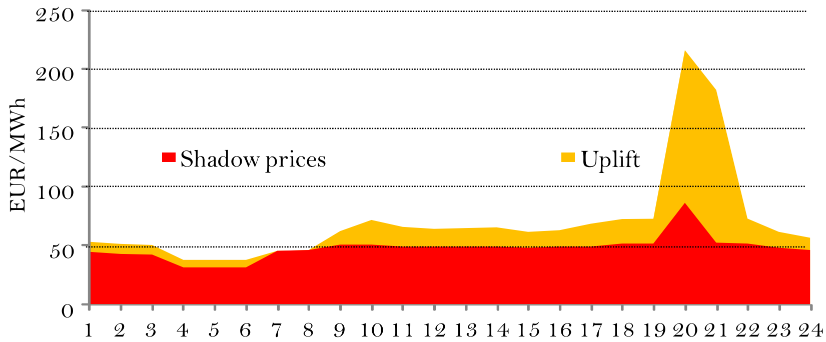


Figure 8. Uplift component in the Irish market, Oct. 19th, 2011[16]

3.3 Methodology overview

This section describes the methodology used in the case example. The model developed for the study consists of three different modules, as shown on Figure 9.

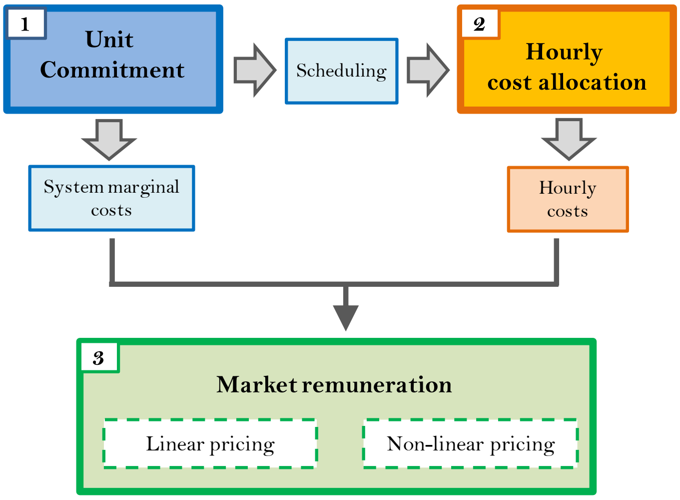


Figure 9. Methodology overview

First, a stylized unit commitment model computes the scheduling and the resulting marginal costs. This model incorporates a detailed representation of O&M costs and their impact on thermal units operation (see Rodilla et al., 2014). Then (module 2), in order to allow for a proper calculation of hourly prices, allocate each unit's production costs (particularly those ones linked to the non-convexities) along the different periods of production. Finally, with all the previous information, the remuneration of the units in the two pricing contexts is determined. Each one of these three modules is described in the annexes.

[16] Source: www.sem-o.com

3.4 Case study

The test system characteristics are:

- A fully thermal mix, consisting of nuclear (10 1 GW power plants) and CCGTs (70 400 MW power plants). Table ii shows the detailed characteristics of the mix (including the assummed value of non-served energy).

Table ii. Test system cost parameters

Technology	Start-up cost [$/start/MW]	Pmax [MW]	Pmin [MW]	No-load cost [$]	Variable fuel cost [$/MWh]
Nuclear	-	1000	1000	0	6.79
CCGT	30	400	160	2202	49.55
NSE	-	-	-	-	2500

- The cost of a major maintenance of the CCGT technology is assumed to be US$ 40 million, and the MIF corresponds to the one denoted in Figure 7 as “Option A”. The maximum number of starts and firing hours are respectively 900 and 24000.
- Two scenarios regarding the penetration of VER are considered. One with no VER capacity installed, and another with 35GW of solar PV capacity. The hourly production profile has been scaled from historical 2010 Spanish solar PV production.

The reason only solar PV is considered, is that it represents the VER that more profoundly affects thermal cycling operation. As an illustration, Figure 10 below shows a week-sample of the hourly production profiles for wind and solar in Spain, normalized to the same installed capacity.

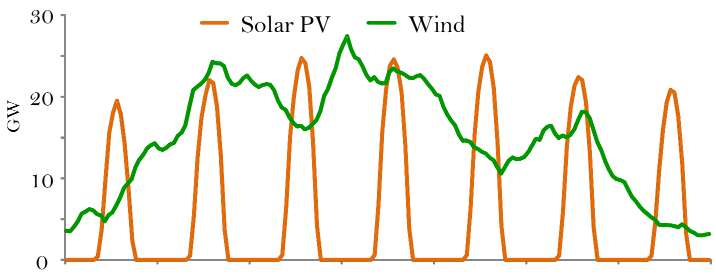


Figure 10. Comparison of wind and solar production profile for 30 GW capacity

The peak demand of the test system is based on the Spanish system. Hourly demand corresponds to the historical values recorded the week from November 8 to November 14 2010. The decision to include such a large amount of CCGT units is to ensure it results most of the time as the marginal technology (as it is the case in a number of European systems today). This condition allows to exclusively focus on the effect of cycling on prices, leaving aside the already well-understood merit order effect.

The unit commitment model has been used to simulate a full week to ensure a sufficiently long planning horizon is considered in commitment decisions. Figure 11 below shows the resulting dispatch in both VER penetration scenarios.

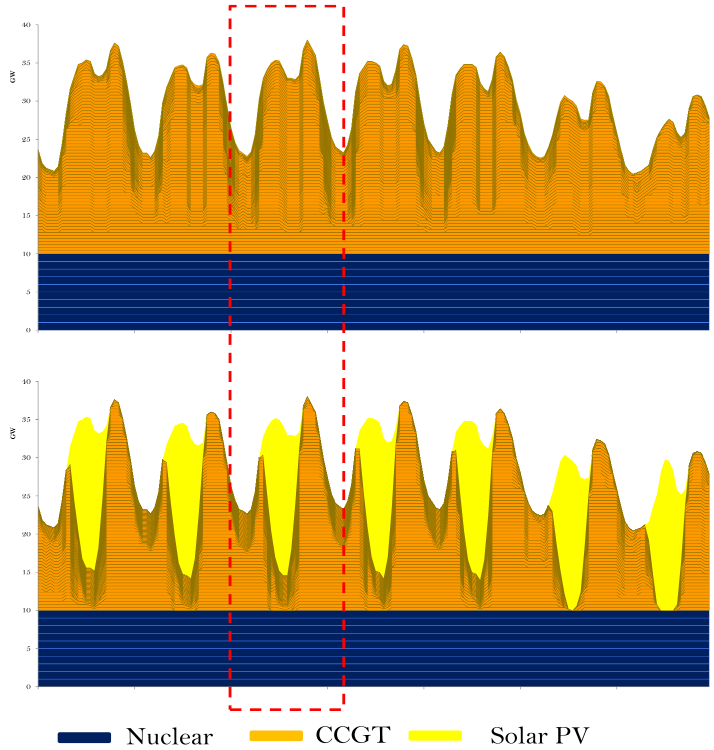


Figure 11. Dispatch result in both VER penetration scenarios

Figure 11 shows how a large penetration of VER increases the need for cycling the units. Solar PV increases the difference between peak and off-peak net demand, and reduces the gap between the inflexible capacity and the net demand during off-peak hours. Therefore, generating units are forced to reduce production to minimum load during a higher number of hours or to stop and start-up more frequently.

Although the full-week dispatch was obtained, next results focus on a particular day, Wednesday (highlighted by the red dotted line in Figure 11). This eliminates for the most part any transient effect due to the limited horizon of the optimization.

As just described, the choice of the marginal technology makes system marginal costs during the day of interest for both scenarios equal the variable cost of a CCGT unit (49.55 $/MWh) (the marginal technology does not change).

3.4.1 The non-linear context: side payments

If marginal cost pricing is applied, CCGT units requires additional payments to recover all start-up and no-load costs, Table iii shows average side payments (calculated as the total side payment divided by total net demand) and the maximum side payment (for a single unit) in both scenarios: with and without solar PV. In the scenario with high solar PV penetration, both the average and the maximum side payment are higher due to start-up cost increases.

Table iii. Average and maximum side payment with solar and without solar

	With solar	Without solar
Average side payment ($/MWh)	9.95	7.69
Maximum side payment ($)	104416	92843

3.4.2 The linear context: uniform uplifts

With the Irish pricing rule, market prices are increased by hourly uniform uplifts, shown in Figure 12.

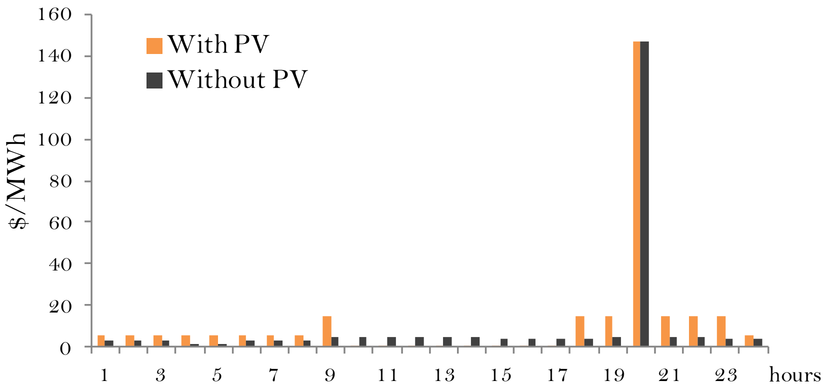


Figure 12. Hourly uniform uplifts in the linear pricing context

The distribution of uplifts through the different hours changes because of the different net load shape after introducing solar PV production. In addition, total uplift increases, although demand payments do not increase proportionally, since demand is different in each hourly period. Weighted average uplift is a better measure of uplift impact, as it reflects the additional payment per MWh of demand. As expected, these uplifts are larger in the case with solar again, because of the increase in fixed operation costs caused by the introduction of VER (see Table iv).

Table iv. Weighted average uplift with solar and without solar

$/MWh	With solar	Without solar
Weighted average uplift	15.99	11.16

3.4.3 Remuneration of generating units

The profitability of conventional plants is affected by the pricing rule. In particular, this effect is expected to mostly impact infra-marginal units, whose operating costs are largely unaffected, but their remuneration could fundamentally change due to differences in market prices. To show this effect, the income of a base-load nuclear unit operating at a constant regime has been computed. Table v shows the resulting income in the four cases (depending on the solar PV scenario and the pricing rule considered) for one of the 1000 MW nuclear power plants.

Table v. Average base-load price for each VER scenario and pricing rule

$/MWh	**With solar PV**	**Without solar PV**
Linear pricing	61.54	59.29
Non-linear pricing	49.55	49.55
Difference	11.99	9.74
Difference in %	24.20 %	19.65 %

As expected, the income in the linear pricing context is always higher than in the non-linear pricing rule, where income is limited to the marginal cost of CCGT units. Using marginal cost pricing, market prices stay the same after VER is introduced, and the remuneration of the base-load plant is unaffected. In the contrary, using the Irish pricing rule, market prices increase as a consequence of the increased CCGT units' cycling, and base-load units receive a higher income.

Another significant result is that the difference between pricing rules (i.e., the relevance of the pricing rule choice) increased in the high VER penetration scenario. This result shows that increased VER penetration can increase the "non-convexity" of the market, in other words, it will increase differences between linear and non-linear pricing rules. This is an important result because the choice of the pricing rule yields not only to different payments for consumers in the short-term but also affects the capacity expansion in the long-term.

3.5 Additional non-convexities

The previous case study used two different generating technologies to highlight the differences in remuneration perceived by an infra-marginal unit (nuclear) running base-load and a marginal unit (CCGT) setting the price most of the time. While these two technologies serve as clear examples of the remuneration regimes of interest, technical peculiarities were set aside to maintain generality in the discussion. In addition to start-up and no-load costs, combined cycle gas turbines present other particular types of non-convexities (Ammari and Cheung, 2013) (Chang et al., 2008). Detailed modeling of a CCGT unit in a unit commitment problem requires additional binary variables which add computational complexity. At the same time, the presence of these binary variables in the cost function complicates the implementation of an efficient pricing rule.

This is illustrated using a piecewise linear representation of a non-convex cost function for CCGT units instead of the linear cost function used before. Table vi shows the additional parameters used to represent CCGT units for each piece of the cost function[17].

Table vi. Additional parameters of CCGT units

Piece 1 of cost function			Piece 2 of cost function		
Pmin [MW]	**Pmax [MW]**	**Variable fuel cost [$/MWh]**	**Pmin [MW]**	**Pmax [MW]**	**Variable fuel cost [$/MWh]**
160	250	51.95	250	400	47.55

The rest of the methodology stays the same; new results are presented in the same format as the previous section.

3.5.1 The non-linear context: side payments

Table vii shows that considering the piecewise linear non-convex cost function for CCGT units increased the need for side payments in all cases. However, the high solar PV penetration scenario still produces higher average and maximum side payments than the one without solar production.

Table vii. Avg. and max. side payments with piecewise linear CCGT cost function

	With solar	**Without solar**
Average side payment ($/MWh)	10.15	8.45
Maximum side payment ($)	106235	99986

3.5.2 The linear context: uniform uplifts

Table viii presents the weighted average uplift for this new case. In the linear context, with no side payments to be increased, the uplift component of the price is the one to represent additional non-convexities. Again, the scenario with solar production requires the higher uplift.

Table viii. Weighted average uplift with piecewise linear CCGT cost function

$/MWh	**With solar**	**Without solar**
Weighted average uplift	16.64	12.17

The new cost function produced additional changes in base-load plants remuneration, as shown in Table ix. In the non-linear case the average price differs with respect to the first case, even if CCGT is always the marginal technology, the marginal price can now

[17] Note these variable costs are adjusted so the efficiency at the maximum power output is the same as before to make simpler comparisons.

take two different values (one for each piece of the cost function)[18]. The average price is higher in the case with solar production but this does not always have to be the case. The additional non-convexities complicate the relation between solar penetration and the marginal price[19].

Regarding the linear pricing context, and in accordance to the higher uplifts encountered, the average price is also higher than the one found in the first study case. As expected, the addition of another non-convexity increased the difference between linear and non-linear pricing rules.

Table ix. Avg. price for base-load plant with piecewise linear CCGT cost function

$/MWh	With solar PV	Without solar PV
Linear pricing	61.74	59.28
Non-linear pricing	49.20	48.84
Difference	12.54	10.44
Difference in %	25.48	21.37

3.6 Conclusions

This case study illustrated the impact that increased penetration of VER has on market prices as a consequence of increased operation (and in particular start-up) cost. In particular, it focuses on the influence of the pricing rule implemented (linear pricing or non-linear pricing) in the market results.

The model used includes a short-term unit commitment and dispatch optimization that takes into account a detailed representation of maintenance drivers and costs, and a post process in which side-payments and uplifts are computed (for the non-linear and linear contexts respectively).

In general, since the linear pricing approach provides all generators with a non-negative adder on top of system marginal costs, and ensures revenue sufficiency (a non-confiscatory market), this method is guaranteed to produce a system-wide total generation profit that is higher-than or equal to the non-linear approach. But internalizing non-convexities in prices does not only mean revenues are higher, it also

[18] This produced a lower average price in the non-linear case although costs did not decrease, which explains the greater need for side payments.

[19] Increasing solar penetration has now two effects in price. When CCGT units are pushed to operate at its minimum power output the marginal price increases (piece 1 of cost function). However, it can also make some units shut down making the remaining CCGT units operate above its minimum power output entering the second piece of the cost function, which decreases the marginal price.

means they are more sensitive to changes in the operating cost structure of the system (such as those derived from an increase in VER production), therefore improving cost-reflectivity of market prices.

The significant differences observed between pricing rules (in market prices and generators' remuneration) can have a long-term impact on the power system, leading to different investment decisions. This dimension was not analyzed in this case study, which focused only on short-term impacts. The following chapter will also consider long-term consequences to fully assess the relevance of pricing rules.

References

Ammari, S., Cheung, K.W., 2013. Advanced combined-cycle modeling, in: PowerTech (POWERTECH), 2013 IEEE Grenoble. pp. 1–5. doi:10.1109/PTC.2013.6652321

Baldick, R., Helman, U., Hobbs, B.F., O'Neill, R.P., 2005. Design of Efficient Generation Markets. Proceedings of the IEEE 93, 1998–2012. doi:10.1109/JPROC.2005.857484

Balevic, D., Hartman, S., Youmans, R., 2010. Heavy-Duty Gas Turbine Operating and Maintenance Considerations. GER-3620L.1 (10/10), GE Energy, Atlanta, GA.

Chang, G.W., Chuang, G.S., Lu, T.K., 2008. A simplified combined-cycle unit model for mixed integer linear programming-based unit commitment, in: 2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century. pp. 1–6. doi:10.1109/PES.2008.4596496

ERCOT, 2011. Verifiable Cost Manual, available at www.ercot.com

McNamara, R. R., 2011. Methodology to Update ISO Default Operations and Maintenance Adder Values, September 7, 2011. Available at http://www.caiso.com.

Pérez-Arriaga, I, J., Batlle, C., 2012. Impacts of intermittent renewables on electricity generation system operation. Economics of Energy and Environmental Policy, vol. 1, No. 2.

PJM, 2012. PJM Manual 15: Cost Development Guidelines, available at www.pjm.com.

PPA (Power Planning Associates), 2002. Dictamen Técnico sobre Costos de Generación de Plantas Térmicas en Colombia para soportar el expediente 7728. In Spanish. April 2002

Rodilla, P., Cerisola, S., Batlle, C., 2014. Modeling the major overhaul cost of gas-fired plants in the unit commitment problem. IEEE Transactions on Power Systems. vol. 29, no. 3, pp. 1001-1011, May 2014 doi: 10.1109/TPWRS.2013.2293604.

SEMO, 2013. SEM-13-089: Uplift Parameters Decision Paper 2014. 12 December 2013. Available at: www.sem-o.com

SEMO, 2014. Trading and Settlement Code. v15.0. 16 May 2014. Available at: www.sem-o.com

Sundheim, E., 2001. Long-Term Service Agreements: Weighing the Risks and Rewards. Power Engineering, vol. 105, iss. 8, 08/01/2001. Available at www.power-eng.com.

Troy, N., Flynn, D., Milligan, M., O'Malley, M., 2012. Unit Commitment With Dynamic Cycling Costs. Power Systems, IEEE Transactions on , vol.27, no.4, pp.2196,2205, Nov. 2012 doi: 10.1109/TPWRS.2012.2192141

Veiga, A., Rodilla, P., Herrero, I., Batlle, C., 2015. Intermittent RES-E, cycling and spot prices: The role of pricing rules. Electr. Power Syst. Res. 121, 134–144. doi: 10.1016/j.epsr.2014.11.030

Annex 3.A Module 1: Short-term unit commitment (UC) model

A short-term unit commitment model is used to compute the optimal dispatch resulting from a perfectly competitive market where generators bid their true costs[20].

This unit commitment model is based on a cost minimization dispatch (considering variable production costs, fuel start costs and variable O&M costs) in which an hourly perfectly inelastic net demand has to be supplied (with a price cap) by a set of thermal generators. Net demand is obtained as the difference between demand and the hourly production profile of VER. This assumes solar producers receive an incentive (tax credits, green certificates, premium for production, priority dispatch, etc.) large enough to ensure all renewable production is scheduled in the market.

The complete formulation presented next is stylized in the representation of operation constraints (some typical constraints are not considered to avoid obscuring the results[21]), but it does include a detailed representation of the most relevant cost components. In particular, maintenance costs are modeled by the explicit representation of LTSA contracts, following the formulation presented in Rodilla et al (2014).

3.A.1 Basic formulation of the unit commitment problem

The complete formulation of the short-term model used to compute the minimum cost dispatch and marginal system costs is as follows:

$$\underset{g_{i,h},u_{i,h}}{Min} \sum_h \sum_i \left[g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + VOMC_i(S_i, FH_i) + NSEC \cdot nse \right] \tag{3.1}$$

$$\sum_i g_{i,h} + nse = L_h \qquad \forall h \tag{3.2}$$

$$g_{i,h} \le \overline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{3.3}$$

---

[20] As pointed out in Baldick et al. (2005), *"in the non-linear context, the multipart offer creates a two-part pricing regime for two commodities, with uniform prices that clear the market for energy, and pay-as-bid prices for the non-convex offer components (e.g. start-up, and no-load)"*. The pay-as-bid nature linked to the non-convex offer components can incentivize a bidding behavior different from truth cost revealing. These incentives are beyond the scope of this work.

[21] For instance, ramp constraints are not considered, but the typical ramp rate for CCGTs is above 10 MW per minute, so this assumption is not an issue even for large solar PV penetration.

$$g_{i,h} \geq \underline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{3.4}$$

$$u_{i,h} = u_{i,h-1} + v_{i,h} - w_{i,h} \qquad \forall i,h \tag{3.5}$$

$$S_i = \sum_{h=1}^{H} v_{i,h} \qquad \forall i \tag{3.6}$$

$$FH_i = \sum_{h=1}^{H} u_{i,h} \qquad \forall i \tag{3.7}$$

Where:

L_h	Represents the net demand value (demand minus solar photovoltaic production) in period h [MW].
$\overline{G_i}, \underline{G_i}$	Respectively represent the maximum and minimum output of thermal unit i [MW].
efc_i	Is the energy fuel variable cost of unit i [\$/MWh].
nlc_i	The no-load cost of unit i [\$].
$omfh_i$	The per-firing hour cost due to operation and maintenance of unit i [\$/fh].
$sufc_i$	Is the start-up fuel cost of unit i [\$/start].
$NSEC$	Is the non-served energy cost [\$/MWh].
$g_{i,h}$	Is the production of unit i in period h [MW].
nse_h	Is the non-served energy in period h [MW].
FH_i	Is the total amount of firing hours of unit i [hours].
S_i	Is the total amount of starts of unit i [starts].
$VOMC_i$	Is the total variable operation and maintenance cost of unit i
$u_{i,h}$	Is the binary commitment variable. It indicates whether unit i is on-line (1) or off-line (0) in period h.
$v_{i,h}, w_{i,h}$	Respectively represent unit's i the start and shut down binary decision in period h.

3.A.2 Modelling non-convex cost functions

The model is expanded in Section 3.5 to include non-convex cost functions for CCGTs, this requires updating the objective function and additional variables and constraints:

$$\underset{g_{i,h},u_{i,h},q_{i,h}^{p},x_{i,h}^{p}}{Min} \sum_{h}\sum_{i}\left[vfc_{i,h} + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + VOMC_i(S_i, FH_i) + NSEC \cdot nse\right] \tag{3.8}$$

Where the variable fuel cost computation is different for CCGT units:

$$vfc_{i,h} = g_{i,h} \cdot efc_i \qquad i \notin CCGT, \forall h \tag{3.9}$$

$$vfc_{i,h} = u_{i,h} \cdot \underline{G_i} \cdot pfc_i^{p=1} + \sum_{p=1}^{p=P} q_{i,h}^{p} \cdot pfc_i^{p} \qquad i \in CCGT, \forall h \tag{3.10}$$

Previous constraints remain the same and the following equations are added:

$$q_{i,h}^{p} \leq u_{i,h} \cdot \overline{Q}_i^{p} \qquad p = 1, i \in CCGT, \forall h \tag{3.11}$$

$$q_{i,h}^{p} \leq x_{i,h}^{p-1} \cdot \overline{Q}_i^{p} \qquad p > 1, i \in CCGT, \forall h \tag{3.12}$$

$$q_{i,h}^{p} \geq x_{i,h}^{p} \cdot \overline{Q}_i^{p} \qquad i \in CCGT, \forall h, p \tag{3.13}$$

$$g_{i,h} = u_{i,h} \cdot \underline{G_i} + \sum_{p=1}^{p=P} q_{i,h}^{p} \qquad i \in CCGT, \forall h \tag{3.14}$$

Where:

pfc_i^p	Is the fuel variable cost corresponding to piece p of the cost function of unit *i* [$/MWh].
$q_{i,h}^p$	Is the production of unit i in period h corresponding to piece p of the cost function of unit *i* [MW].
$\overline{Q}_i^p$	Is the maximum production corresponding to piece p of the cost function of unit i [MW].
$x_{i,h}^p$	Is a binary variable set to 1 if production in period h corresponding to piece p of the cost function of unit *i* is at its maximum.

A generic non-convex cost function is shown in Figure 13 to clarify the formulation.

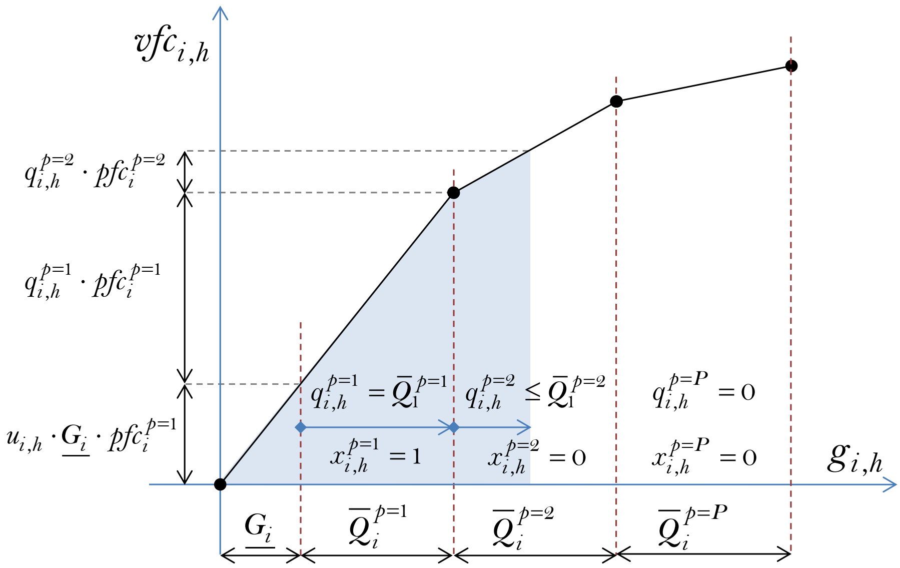


Figure 13. Sample piecewise linear non-convex cost function

3.A.3 Modelling O&M cost through the MIF:

Moreover, for each segment defining the piece-wise-linear approximation of the MIF we have an equation:

$$\begin{aligned} & S \cdot (MMC \cdot FH_a - MMC \cdot FH_b) \\ & -FH \cdot (MMC \cdot S_a - MMC \cdot S_b) + VOMC \cdot (S_a \cdot FH_b - S_b FH_a) \leq 0 \end{aligned} \tag{3.15}$$

Where the segment of the piece-wise-linear MIF function is delimited by points $A(FH_a, S_a)$ and $B(FH_b, S_b)$, provided that $FH_a \geq FH_b$ and $S_a \geq S_b$ (see Figure 14).

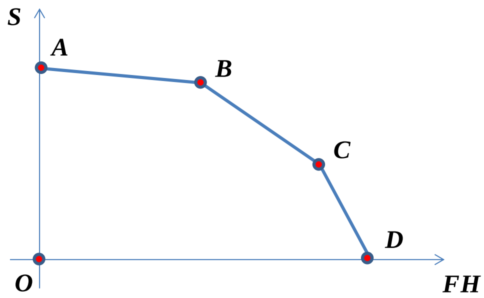


Figure 14. Piece-wise linear MIF

In the particular case of a MIF defined by a rectangle, the UC model needs two additional equations for each unit:

$$OMC \cdot FH_{Max} \cdot S_{Max} - OMC_{Total} \cdot FH_{Max} \cdot S \leq 0 \tag{3.16}$$

$$OMC \cdot FH_{Max} \cdot S_{Max} - OMC_{Total} \cdot FH_{Max} \cdot S \leq 0 \tag{3.17}$$

Annex 3.B Module 2: Hourly production cost allocation

Both the linear and non-linear pricing rules ensure that all units at least recover all the costs derived from to their operation in the trading horizon considered (i.e., one day). The computation of daily side payments or hourly uplifts takes as input the total costs of each plant; what fuel, commitment or O&M costs exactly to assign to each day, or even, each hourly period, requires some assumptions.

3.B.1 Energy and start-up fuel costs hourly allocation

The criteria to allocate fuel costs is rather straightforward:

- The energy fuel (and no-load) costs associated to the units' production is assumed to be incurred in the hours the unit is producing.
- The fuel cost associated to each start is evenly allocated to the hours during which a unit is in operation between start-up and shut-down. This implies start-up costs may be spread across multiple days. This is the approach used in some markets (e.g. SEM), but not all.

3.B.2 O&M cost hourly allocation

Different ways to allocate operation and maintenance costs could be conceived. A simple and common approach to divide total costs by energy production, but this does not take into account the relevant effect of start-ups. Since both the number of firing hours and the number of starts are the variables triggering the major maintenance, it seems reasonable to allocate O&M costs between these two variables.

To clarify the methodology proposed, consider the maintenance contract presented in Figure 15 (the most general Maintenance Interval Function, previously denoted by Option C). If a plant subject to this contractual agreement produces as a pure base-load unit, then the unit would perform the maintenance at the point M_B, after it has expired the maximum amount (FH_{Max}) of hours possible.

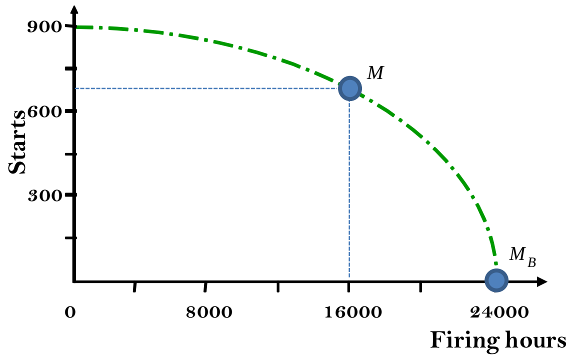


Figure 15. O&M cost allocation

If OMC_{Total} represents total O&M costs, then the previous base-load unit could allocate total maintenance costs to the firing-hours variable. The resulting per firing hour cost due to O&M ($fhomc$) equals:

$$fhomc = OMC_{Total} / FH_{Max} \tag{3.18}$$

The $fhomc$ cost is a suitable way to allocate maintenance costs as long as the unit operates in a base-load regime, since the unit would have fully internalized the cost by the time a major maintenance takes place (since $fhomc \cdot FH_{Max} = OMC_{Total}$).

In general, the regime will not be purely base-load, and the combination of cumulative firing hours and starts will trigger the maintenance. For example, point M in the figure, after FH_M firing hours, and S_M starts (16000 hours and 675 starts in the example).

In this case, starts reduce the number of available firing hours, and vice versa. If only the previous value for $fhomc$ is used to internalize maintenance costs, when maintenance is triggered, a cost equal to $(FH_{Max} - FH_M) \cdot fhomc$ will be unrecovered. From this perspective, and averaging the effect of each start, the individual start up cost due to O&M ($suomc$) equals:

$$suomc = \frac{(FH_{Max} - FH_M) \cdot fhomc}{S_M} \tag{3.19}$$

Therefore, this allocation only requires the cumulative number of firing hours and starts when the maintenance takes place. Given that the case example only includes one week, the resulting number of weekly hours and starts is assumed to remain stable (i.e., same ratio between firing hours and starts) for the remaining time until maintenance conditions are met.

Figure 16 highlights the relevance of the start-up cost adder ($suomc$), the resulting adder value for a CCGT is represented as a function of annual operating conditions (using the data from the case example for the maintenance contract).

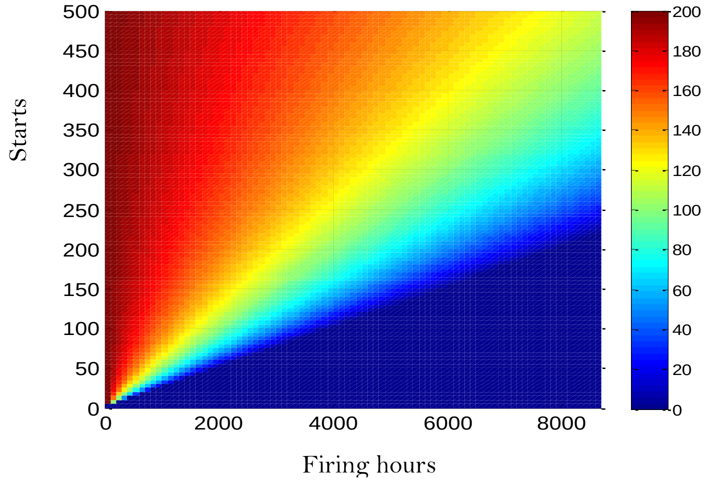


Figure 16. Start adder component ($/start MW) vs firing hours and starts

For a constant number of firing hours, the higher the number of starts the higher the cost of each start. Conversely, if the number of starts remains constant, the lower the number of firing hours, the higher the cost of each start.

Annex 3.C Module 3: Remuneration

3.C.1 Non-linear pricing: Side-payment computation

Individual daily side payments are determined as the difference between total operating costs and revenues (marginal price times production):

$$SidePayment_{i,day} = \max(\sum_h TotalCost_{i,h} - \sum_h \lambda_i \cdot g_{i,h}, 0) \qquad \forall h \in day \tag{3.20}$$

Where

$TotalCost_{i,h}$ Is the total cost of unit i in hourly period h [$].

$$TotalCost_{i,h} = g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + OMC_i(S_i, FH_i) \tag{3.21}$$

$g_{i,h}$ Is the production of the unit i in period h [MW].

λ_h Is the marginal price in period h [$/MWh].

In this context, the income of each generating unit per day is:

$$\sum_h \lambda_i \cdot g_{i,h} + SidePayment_{i,day} \qquad \forall h \in day \tag{3.22}$$

3.C.2 Linear pricing: Uniform uplift computation

This model mimics the algorithm used in the Irish market: positive hourly uplifts are added to system shadow prices. Uplifts fulfill (tradeoff between) two simultaneous conditions: all generating units have to recover all their production costs, and demand payments are minimized. A term representing hourly uplifts squared is added to the objective function to reduce price peaks, in SEMO (2014) this term is referred to as the Uplift Profile Objective.

The formulation of the linear optimization model used to compute uplifts is:

$$Min\ a \cdot \sum_h \left(\lambda_h + uplift_h\right) \cdot L_h + \beta \cdot \sum_h {uplift_h}^2 \tag{3.23}$$

Subject to:

$$\sum_h TotalCost_{i,h} \leq \sum_h \left(\lambda_h + uplift_h\right) \cdot g_{i,h} \qquad \forall i \tag{3.24}$$

$$uplift_h \geq 0 \qquad \forall h \tag{3.25}$$

Where:

$uplift_h$ Is the uplift in period h [$/MWh].

L_h Is the load in period h [MW].

a,β Adjust the weight of each term: $a = 0$ and $\beta = 1$ (SEMO, 2013).

In this context, each generating unit receives each day:

$$\sum_h (\lambda_i + uplift_h) \cdot g_{i,h} \qquad \forall h \in day \tag{3.26}$$

4 THE ROLE OF PRICING RULES IN INVESTMENT INCENTIVES

The objective of this case study is to assess to what extent long-term investments incentives can be affected by the pricing rule implemented. The analysis uses a long-term capacity expansion model where investment decisions are based on market remuneration. The optimal mix is computed for a real-size thermal system with high renewable energy penetration (since its intermittency enhances the relevance of non-convexities), when considering alternative pricing schemes.

Traditional marginal cost pricing is compared with an alternative linear pricing rule (Integer Relaxation). Results show that the implementation of one or the other pricing rule can have a significant effect on the investment incentives perceived by generation technologies, and the linear pricing rule leads to more efficient investment decisions.

4.1 Introduction

Beyond the primary aim of compensating for operations costs, an instrumental role of the prices resulting from a well-designed and well-functioning electricity market is to allow generators making efficient (well-adapted) investment decision to recover their capital costs. In this sense, short-term market prices should be the proper signal for market agents to expand the system in the most efficient way.

In this context, for infra-marginal units the difference between market prices and their operation costs should suffice to finance their capital costs. Given the differences in market prices from one pricing rule to another, different investment decisions should be expected under each pricing rule. This long-term consideration should help to discern which of the pricing approaches is more appropriate (Vázquez, 2003). Nonetheless, it has been pointed out that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003), (Ring, 1995).

This chapter further analyses the long-term impact of different pricing rules in an energy mix if investment is driven by short-term market prices. Intuitively, the linear pricing rule, which provides higher remuneration to base-load units, should incent more investments in this technology. As pointed out by Vázquez (2003):

> *"Although, when exclusively studying operation decisions, it seems that only variable costs need to be considered (in price formation); when the impact of the price on investment decisions is considered it is observed that it also has to partially include non-convex operation costs. When including in the price the corresponding part of start-up and no-load cost of the marginal unit, a larger remuneration is given to infra-marginal units. These infra-marginal units will find a greater long-term incentive to invest, and as a consequence will partially substitute the marginal technology."*

The magnitude of this effect is still unclear, although as discussed in Chapter 3, it is highly influenced by the penetration renewable energy sources (RES-E), which increases conventional thermal plants cycling. These changes in system operation augment the share of non-convex costs (mainly start-up costs) in total operation costs, and therefore increases the differences in remuneration received under each of the pricing rules, especially for base-load plants.

4.2 Methodology overview

The goal of the proposed approach is to compute the generation mix that is perfectly adapted to the incentives produced by a given market and pricing rule. The analysis relies on a detailed long-term greenfield capacity expansion optimization of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints are considered in the simulation (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.). These three technologies represent base-load, mid-load, and peak-load plants. The hourly electricity demand profile is taken from the historical demand for Spain in 2012 (assumed to be perfectly inelastic). The generation mix includes a fixed investment in RES-E, assuming its profitability does not depend on market prices, but on some additional incentive mechanism. This translates into a high penetration of solar photovoltaic (PV). The PV production profile has been scaled from the 2012 hourly production profile in Spain, and the dispatch allows for PV production curtailment when economical. Figure 17 summarizes the different stages of the model, described in the following sections.

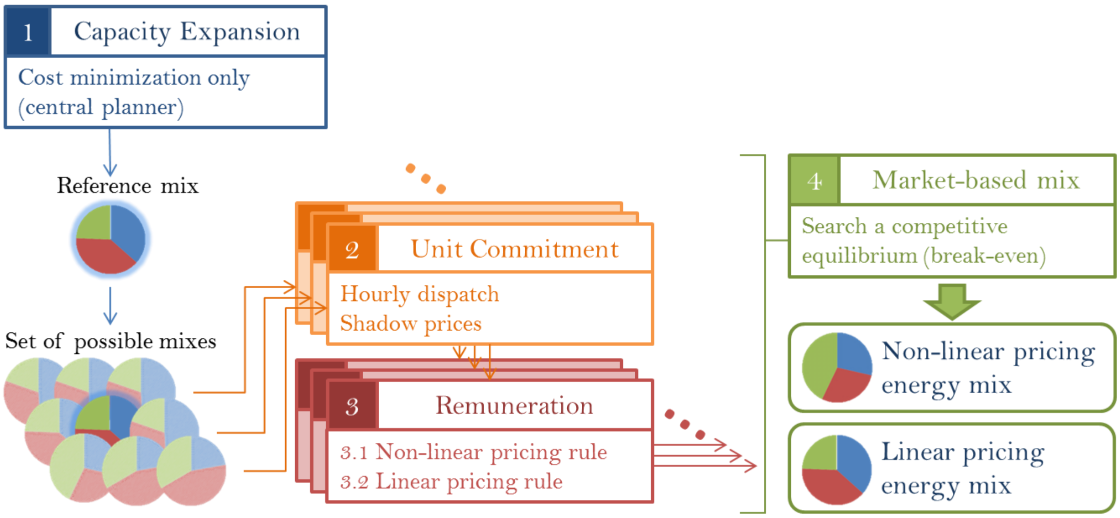


Figure 17. Methodology summary diagram

4.2.1 Module 1: Reference generation mix

Module 1 calculates the least-cost energy mix using a traditional capacity expansion model as in a centralized planning case[22]. This energy mix is used only as initial reference for the subsequent search of the perfectly adapted mix corresponding to each of the pricing rules. Since market prices should drive investment towards the least cost generation mix, the market-based mixes to be obtained later will not deviate substantially from this reference.

The set of possible mixes considering all combinations of the three thermal generation technologies would amount to n^3 possibilities (where n is the maximum number of units considered for each technology). In a real size example this produces a number of possibilities in the order of 10^6. To reduce the search space, mixes that significantly deviate from the initial reference are excluded, reducing the set to some thousand combinations only. The criteria for the exclusion is designed to minimize the

[22] The model used in this step includes a detailed representation of both expansion and operation. The formulation is similar to the one used for the Unit Commitment model, but the number of units for each technology is in this case a variable of the problem and investment costs are included in the objective function.

computation time[23] of following modules while maintaining an extensive set of possible solutions, so that an optimum can be found.

Each possible solution is evaluated separately in modules 2 and 3. Module 4 finds an optimum once the whole set of possible solutions is fully characterized.

4.2.2 Module 2: Short-term Unit Commitment

Module 2 takes as an input a given energy mix, generation offers (assuming perfect competition) and simulates the day-ahead market outcome for a full year. The output of this module includes the detailed economic dispatch and hourly marginal costs. The UC formulation is detailed in Annex 4.A.

4.2.3 Module 3: Price and remuneration calculation

Module 3, from the dispatch and marginal costs produced by module 2, calculates the remuneration of each of the generation units committed, computing first the corresponding hourly prices and as a result the side-payments needed for the units to recover their full short-term operation costs under both different pricing rules.

The computation of prices and side-payments is detailed in Annex 4.B. No reserves or other ancillary services are considered in this simulation since the focus is on differences produced exclusively by the aforementioned pricing rules on the day ahead energy-only market[24].

4.2.4 Module 4: Market-based mix search

Module 4 compares all the previous generation mixes to obtain, for each of the pricing rules, the best adapted mix. The aim of this direct search approach is to find the investment decisions a competitive market would carry out. This necessarily implies that all market agents are at least break-even. In other words, an agent would choose to invest if and only if short-term market remuneration fully ensures the recovery of both investment and operation costs. On the other hand, a perfectly competitive market will remove excessive profits, since competitors would enter the market and depress prices

[23] It took 2h and 37 min to analyze the real-size case example presented in this paper. The model was run using CPLEX on GAMS on an Intel Core i7@ 2.8 GHz, 3.5 GB RAM.

[24] This is also the scope of some well-known references on the topic like Hogan and Ring (2003) and Baldick et al (2005).

down to the break-even point. Therefore, the equilibrium is reached for the set investment closer to the break-even point. Additional details are provided in Annex 4.C.

4.3 Results

Three different energy mixes are calculated and compared. First, the least-cost (reference) energy mix from a centralized perspective is obtained by module 1. Around this reference mix a set of possible mixes (containing 3706 potential solutions) is built. All these possibilities are characterized by modules 2 and 3. Module 4, considering market-based investment decisions, selects the two mixes that best adapt to a non-linear and a linear pricing rule.

Figure 18 shows first the minimum cost reference mix followed by the mixes resulting from applying the two different pricing rules. Both the mix produced by the linear pricing rule and the mix produced by the non-linear pricing rule deviate from the reference mix. In fact, none of the pricing rules supports the reference energy mix (i.e. they do not provide sufficient remuneration to make all units in the reference mix profitable), which would be a desirable characteristic of a pricing rule. Both pricing rules require a deviation from the reference mix including a slight decrease in total capacity.

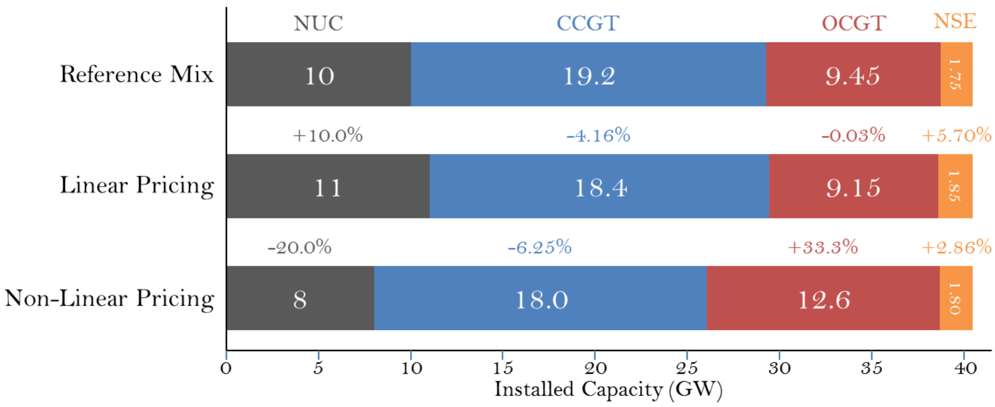


Figure 18. Generation mix results

The major difference is the shift in capacity of nuclear and OCGT (base-load and peak-load) which in the non-linear pricing context substantially deviates from the reference. Some small differences between these three mixes are a result of lumpiness since only discrete investments are considered. Bigger differences are more representative of the pricing rule influence.

To gain more insight, the break-even frontiers for the three technologies in the case study are shown in Figure 19 and Figure 20. See Annex 4.C for a description of this representation. The figure shows 2-dimensional break-even frontiers obtained for all combinations of CCGT and OCGT units and only discrete combinations of nuclear power plants. These frontiers can be thought of as the contour lines of the three surfaces that should intersect only at the break-even solution point. This way, a point where all three contour lines intersect will indicate the desired solution but this point may not be represented in the figure since the optimal continuous solution could require a non-discrete level of nuclear capacity.

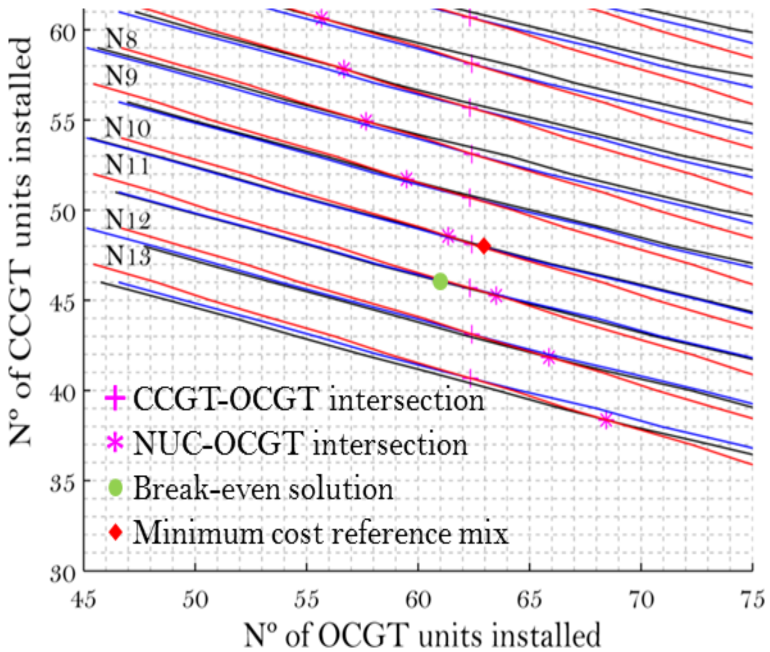


Figure 19. Break-even frontiers for the linear pricing rule

Figure 19 shows the result for the linear pricing rule. To easily find the point where all three surfaces intersect look at the crosses (+) which represent the intersection of the CCGT (blue) and OCGT (red) lines and the asterisks (*) which represent the intersection of the NUC (black) and OCGT (red) lines. The perfectly adapted generation mix to be installed under a linear pricing rule would have between 10 and 11 nuclear power plants. Since we are assuming that only discrete investments are possible, the final solution requires 11 nuclear power plants and is indicated by the green dot. The red diamond points the minimum cost reference mix, by a very short distance, it is located outside of the feasible boundary. Therefore, this particular linear pricing rule does not provide optimal investment incentives, although the difference with the optimal mix is very small.

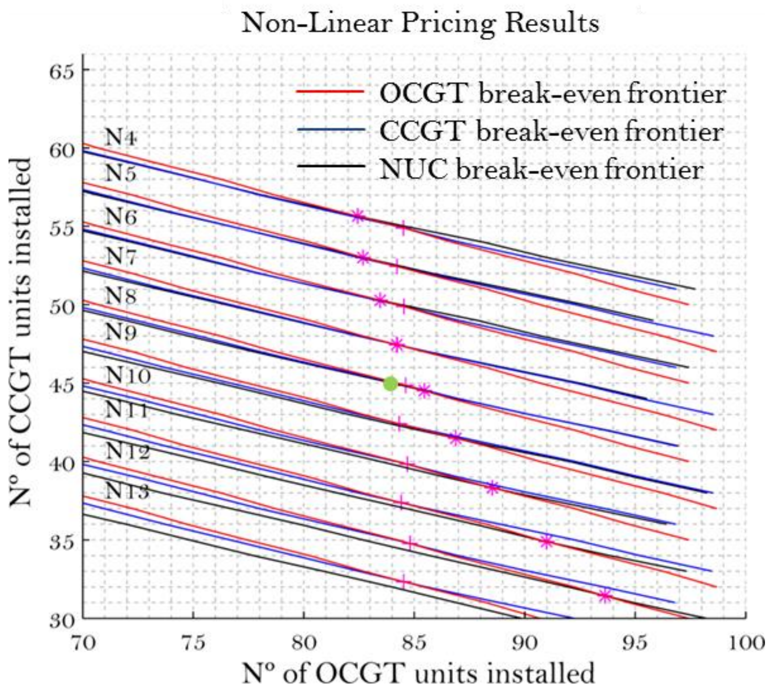


Figure 20. Break-even frontiers for the non-linear pricing rule

Figure 20 shows the results for the non-linear pricing rule. The ideal solution would lie between 7 and 8 nuclear power plants but the discretization simplifies it to 8. Note the difference in the horizontal axis; in this case the perfectly adapted mix requires a totally different amount of OCGT capacity and the reference mix lies out of the bounds of this plot.

This figure helps to discern what is the trend produced by each of the pricing rules. Linear pricing rules attract capital intensive technologies in alignment with the desired minimum cost energy mix. Non-linear pricing rules produce price signals that do not include non-convex costs and thus, infra-marginal units that could lower total operation costs result unprofitable and are not installed. The gap left by the lack of base-load capacity is filled with peak-load capacity with lower investment costs and higher variable costs.

Figure 21 shows in descending order the hourly market prices produced by each of the pricing rules. Note each curve corresponds to a different mix, corresponding to the market-based investment decisions. The non-linear price consists of four different regimes; the price is set to C^{NSE} when not enough capacity is available, the other two steps correspond to OCGT and CCGT variable costs. Nuclear power plants can never be marginal since they are not able to regulate their output, therefore the price is set to zero when production exceeds demand and solar PV production is curtailed. The linear pricing rule is not limited to these four steps and a continuum of prices is possible.

Compared to the non-linear case, the price is lower when the additional nuclear power plants substitute CCGT units and when CCGT units replace OCGT units. Figure 22 shows the other side of the coin, the daily side-payments which, as expected, are much lower with linear pricing rule.

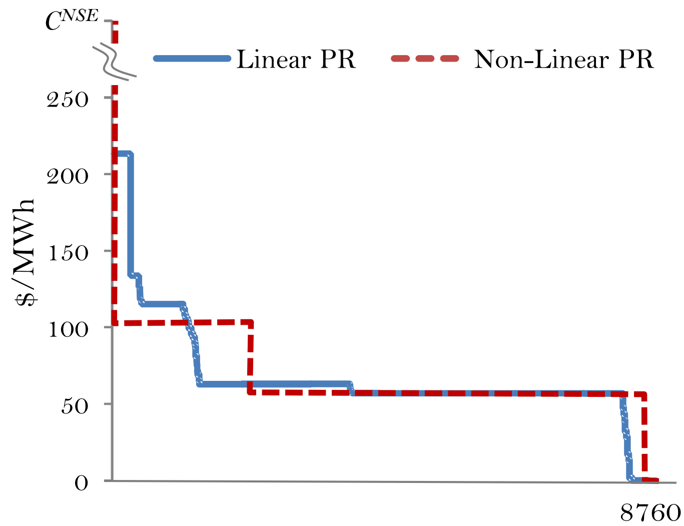


Figure 21. Price-duration curve for the linear and non-linear pricing rules

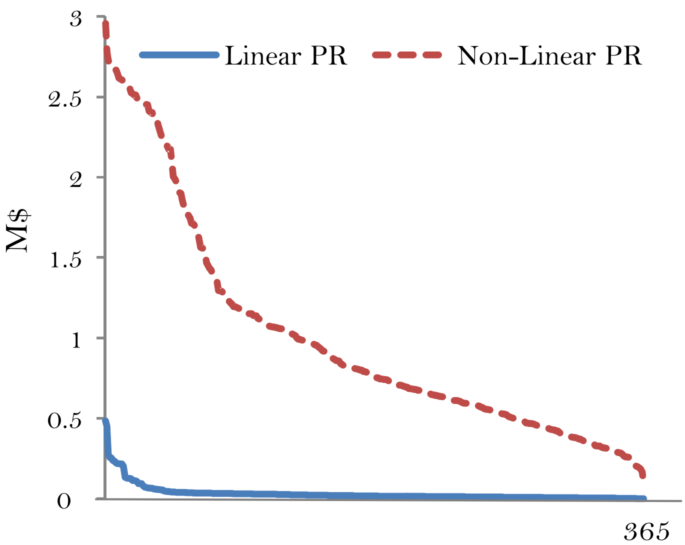


Figure 22. Monotone curve of daily discriminatory side-payments

4.4 Discussion

This section qualifies the results presented previously to determine the relevance of the pricing rule and to clarify some common misconceptions.

While pricing rules clearly affect the energy mix, these differences should be quantified in terms of total cost (investment + operation + non-served energy) of the mix installed. This is the variable to be minimized in an expansion planning problem.

Figure 23 details the share of each component of total costs. It is clear that the linear pricing energy mix is composed of more capital intensive technologies with lower variable costs. Interestingly, the share of non-convex costs (no-load and start-up costs) is relatively small (around 7%) although these are responsible for the price differences between each of the pricing rules and thus, responsible for the difference in the final energy mix.

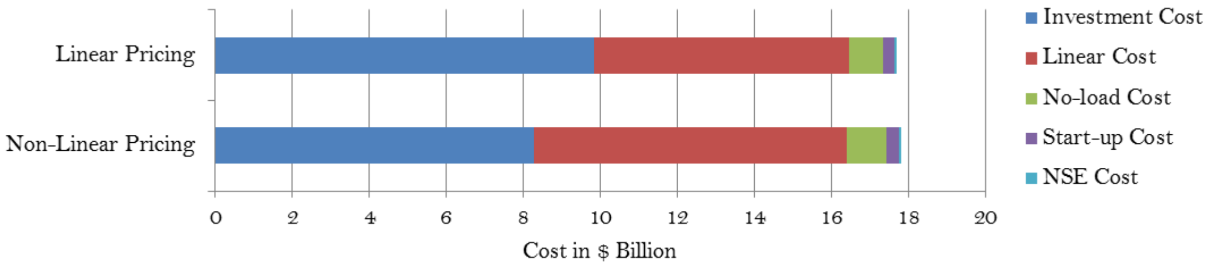


Figure 23. Cost structure of each generation mix

In particular, start-up costs only represent around 1.5% of total costs. This suggests that the screening curves (SC) method (Phillips et al., 1969) could help gain some insight on the results. Figure 24 uses an alternative representation of the SC where the horizontal axis (which generally represents hours of operation of each generation technology) here represents installed capacity. This simply requires a change of variable using the relation between time and power given by the net load-duration curve of the system[25]. This type of representation reflects the total cost per MW of installed capacity of each of the technologies at each of the load levels (under the simplified dispatching assumptions of the SC methodology).

[25] See Batlle & Rodilla (2013) for a more-in-detail explanation of this alternative way to represent the SC methodology

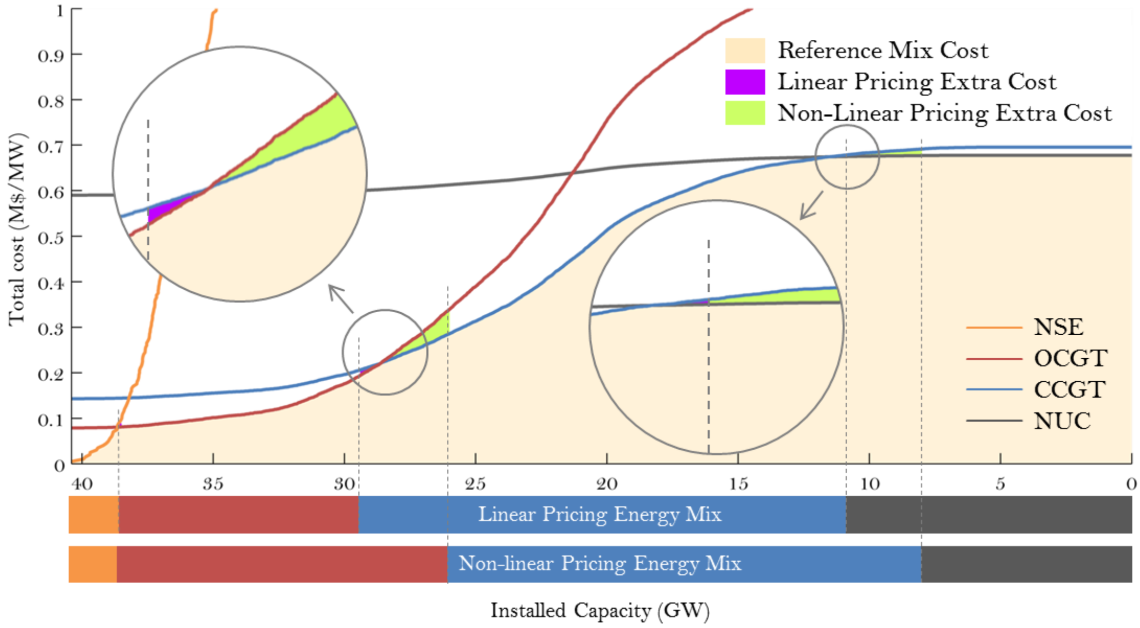


Figure 24. Screening curves representation of total costs

This figure should help interpret what at first might seem a counterintuitive result: the structure of the optimal mix changes significantly as a consequence of the pricing rule implemented, but the total costs are relatively affected to a lower extent. This representation shows that the potential cost differences from different mixes (areas between the screening curve of each technology) are much smaller than total costs.

The total cost of the optimal mix obtained with the SC method is the solid area of the figure above. This is the optimal mix because modifying the installed capacity of any technology increases this area. From this perspective, the additional area obtained, for example, when substituting some of the optimal base-load capacity with mid-load capacity because of the non-linear pricing rule, represents the extra cost derived from the inefficient price signals. Extra costs are highlighted in a different color for each pricing rule. The extra cost derived from the non-linear pricing mix is represented by green areas in the figure, showing an excess of peak-load capacity and a lack of base-load capacity.

Table x compares the total cost for each of the three generation mixes obtained. The difference in total cost between a mix and the reference mix can be interpreted as a measure of the inefficiency of each pricing rule.

Table x: Total cost comparison of the resulting mixes

	Total Cost $ Million	Absolute Difference $ Million	Relative Difference %
Minimum Cost Reference Mix	17,692		
Linear Pricing Energy Mix	17,693	+0.584	+0.0033
Non-Linear Pricing Energy Mix	17,816	+124.074	+0.7013

As already illustrated by the SC, the percentage difference with respect to the minimum cost may seem relatively small. To put it in perspective, it is necessary to know what the maximum impact of a sub-optimal investment decision can be. For instance, for the data considered, a mix in which only CCGT units are installed would only increase total costs by a 3% with respect to the minimum cost reference mix. however, Therefore, a 0.7% impact (given 3% was the impact of one of the worst investment decisions possible) sets the pricing rule choice as one of the most relevant market design elements.

As a rule of thumb, a policy decision responsible for a 1% improvement in market welfare typically causes at least a 10% change in the allocation of welfare[26]. This is, while overall gains may be small, the distributional effects of changing the rules of the game can be relatively large. This policy-maker curse call for a very carefully consideration of other consequences of changing the pricing rule. While the case study demonstrated the long-term benefits in a static setting, the immediate effect of a different pricing rule would be to over compensate some units while under compensating others, until new investments re-adapt the mix. Table xi compares the difference in the remuneration of each technology when applying (changing) a pricing rule to the adapted-to-the-other-pricing-rule mix. These changes are quite relevant, the non-linear rule does not produce sufficient remuneration for the linear mix and the linear rule produces excessive remuneration for the non-linear mix.

Table xi: Investment cost recovery vs generation mix - pricing rule combination

	Linear mix and non-linear rule	Non-linear mix and linear rule
OCGT	110.86 %	104.79 %
CCGT	78.011 %	153.47 %
NUCLEAR	88.146 %	114.95 %

This allows two additional conclusions. First, the performance of one or the other pricing rule can only be judged in the long run. It would make no sense to evaluate the suitability of one rule on the basis of the resulting prices for a mix that is not adapted to said pricing rule. However, the short-term effect still needs consideration. A change in the pricing rule would produce an economic imbalance requiring new investments but

[26] Attributed to Professor Benjamin F. Hobbs.

also divestments that could take a long time before a new economic equilibrium is reached. Therefore, regulators should not change a particular pricing rule without first understanding both the long-term gains and the negative short-term impact.

4.5 Conclusions

A practical and computationally efficient methodology to compare the long-term effect of pricing rules in the investment signals perceived by market agents is proposed. The model allows computing the expected mix to be installed under different pricing rules.

A real size case example was used to compare two pricing rules; a non-linear pricing rule resembling typical market practices in the US and a linear pricing rule reflecting recent trends. Two important results can be extracted from this simulation. First, the way in which non-convex costs are reflected in the uniform price can have a significant impact in the investment signals perceived by market agents and the linear pricing rule seems to promote a more efficient energy mix. Second, contrary to what a superficial analysis may suggest, a linear pricing rule does not necessarily produce higher energy prices than a non-linear pricing rule; in fact it can lower the price once considered that lower variable costs technologies will enter the mix.

The results presented in this chapter suggest that a properly designed linear pricing rule can be more efficient in the long term. But it has been evidenced that adapting a market from an existing non-linear settlement mechanism (or the other way around) could be a problematic process that requires careful planning.

References

Baldick, R., Helman, U., Hobbs, B.F., O'Neill, R.P., 2005. Design of Efficient Generation Markets. Proceedings of the IEEE 93, 1998–2012. doi:10.1109/JPROC.2005.857484

Batlle, C. & Rodilla, P., 2013. An enhanced screening curves method for considering thermal cycling operation costs in generation expansion planning. IEEE Transactions on Power Systems, vol. 28, no. 4, pp. 3683-3691, Nov. 2013.

Black and Veatch, 2012, Cost and performance data for power generation technologies. Prepared for the National Renewable Energy Laboratory, February 2012. Available at bv.com/docs/reports-studies/nrel-cost-report.pdf.

Gollmer, R., Nowak, M.P., Römisch,W., Schultz, R., 2000. Unit commitment in power generation – a basic model and some extensions. Ann. Oper. Res. 96, 167–189. doi: 10.1023/A:1018947401538

Herrero, I., Rodilla, P., Batlle, C., 2015. Electricity market-clearing prices and investment incentives: The role of pricing rules. Energy Economics 47, 42–51. doi:10.1016/j.eneco.2014.10.024

Hogan, W., Ring, B.J., 2003. On minimum-uplift pricing for electricity markets. Electricity Policy Group.

Kumar, N., Besuner, P., Lefton, S., Agan, D., Hilleman, D., 2012. Power Plant Cycling Costs. Intertek APTECH. Available at www.nrel.gov. April 2012.

Morales-España, G., Latorre, J.M., Ramos, A., 2013. Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem. IEEE Transactions on Power Systems, vol. 28, no. 4, pp. 4897-4908, Nov. 2013.

Palmintier, B., Webster, M., 2011. Impact of unit commitment constraints on generation expansion planning with renewables. Power and Energy Society General Meeting, 2011 IEEE, pp. 1–7, 24-29 July 2011.

Phillips, D., Jenkin, F.P., Pritchard, J.A.T., Rybicki, K., 1969. A mathematical model for determining generating plant mix. Proceedings of the Third IEEE PSCC, Rome.

Ring, B.J., 1995. Dispatch based pricing in decentralised power systems. Ph.D, Thesis Dissertation. University of Canterbury 1995, p. 213.

Vázquez, C., 2003. Modelos de casación de ofertas en mercados eléctricos. PhD (in Spanish). Institute for Research in Technology. Comillas Pontifical University.

Annex 4.A UC formulation

An accurate short-term simulation is necessary to obtain precise results in the long term, however, to maintain the model computationally tractable, it is necessary to take some simplifications. A common approach is to consider only a few representative weeks instead of a full year. This approach could have been successful for other purposes but it was not appropriate in this case. This is because important discontinuities that affect the long-term problem are introduced when this simplification is applied. For example, the amount of time intervals where scarcity prices are reached is a key variable to determine the long-term adequacy of an energy mix. If properly determined (i.e. if the price cap is a good proxy of demand's utility), this price allows investment cost recovery for all units in general, and peak-load units in particular, for the optimal mix. If only a few weeks are considered in the problem, a discontinuity is introduced in the number of time intervals in which the price is at the non-served energy price level. For example, if four weeks were considered and the result was then scaled to a year, the number of intervals with NSE price in a week would be multiplied by thirteen. This discontinuity produces big differences in the remuneration of all units when small changes are made in the mix yielding unrealistic results. Therefore, a full year representation is needed.

To accurately represent the short-term dynamics of power plants and still being able to run this simulation for a whole year with a computationally tractable problem, the UC formulation is based on a common clustered formulation proposed for example in Gollmer et al. (2000) and later applied by Palmintier and Webster (2011). This means technically identical units are grouped representing commitment decision with integer variables instead of binary variables. Clustering units speeds computation and still allows for a very accurate representation of the UC.

4.A.1 Indexes and sets

$g \in G$	Generating technologies
$t \in T$	Hourly periods
$g \in G^{MR}$	Must-run generating technologies

4.A.2 Parameters

C_g^{LV}	Linear variable cost of a unit of technology g [$/MWh]
C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]

C_g^{SU}	Start-up cost of a unit of technology g [$]
D_t	Load demand in hour t [MWh]
PV_t	Solar photovoltaic available production in hour t [MWh]
$\overline{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]
RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
N_g	Number of units installed of technology g

4.A.3 Variables

nse_t	Non-served energy in hour t [MWh]
$p_{g,t}$	Power output at hour t of all technology g units above $\underline{P}_g$ [MW]
pv_t^{spill}	Solar photovoltaic energy spill in hour t [MWh]
$u_{g,t}$	Number of units of technology g committed at hour t
$v_{g,t}$	Number of units of technology g starting-up at hour t
$w_{g,t}$	Number of units of technology g shuting-down at hour t

4.A.4 Formulation

$$\min \sum_{t \in T} \left[\sum_{g \in G} \left[C_g^{NL} u_{g,t} + C_g^{LV} \left(\underline{P}_g u_{g,t} + p_{g,t} \right) + C_g^{SU} v_{g,t} + C_g^{SD} w_{g,t} \right] + C^{NSE} nse_t \right] \tag{4.1}$$

$$s.t. \quad \sum_{g \in G} \left[\underline{P}_g u_{g,t} + p_{g,t} \right] + PV_t - pv_t^{spill} = D_t - nse_t \qquad \perp \rho_t \qquad \forall t \tag{4.2}$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \qquad \forall g \notin G^{MR}, t \tag{4.3}$$

$$p_{g,t} \le \left(\overline{P}_g - \underline{P}_g \right) u_{g,t} \qquad \forall g \notin G^{MR}, t \tag{4.4}$$

$$p_{g,t+1} - p_{g,t} \le RU_g \qquad \forall g \notin G^{MR}, t \tag{4.5}$$

$$p_{g,t-1} - p_{g,t} \ge RD_g \qquad \forall g \notin G^{MR}, t \tag{4.6}$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbf{Z} \qquad \forall g \notin G^{MR}, t \tag{4.7}$$

$$u_{g,t} = N_g, \quad v_{g,t}, w_{g,t} = 0 \qquad \forall g \in G^{MR}, t \tag{4.8}$$

$$p_{g,t} = N_g \left(\overline{P}_g - \underline{P}_g \right) \qquad \forall g \in G^{MR}, t \tag{4.9}$$

$$pv_t^{spill} \le PV_t \qquad \forall t \tag{4.10}$$

$$p_{g,t}, nse_t, pv_t^{spill} \geq 0, \quad p_{g,t}, nse_t, pv_t^{spill} \in \mathbf{R} \qquad \forall g,t \tag{4.11}$$

Equation (4.1) shows the objective function, which is a sum of all operation costs (no-load cost, linear-variable cost, start-up cost and shut-down cost) and the value of non-served energy. Restriction (4.2) equals production (allowing solar PV production to be curtailed if needed) with demand minus non-served energy. As well-known, its dual variable ρ_t represents the marginal cost of the system for each time interval. As shown in equation (4.7), commitment variables are integer with the upper bound being the number of units installed. In this model we consider a must-run restriction for nuclear power plants so the constraint (4.9) fixes the power output to its maximum. For an extensive description of a UC model see Morales-España et al. (2013).

4.A.5 Data

The power system modeled features a rather significant solar PV penetration (19.2 GW-peak). The demand profile is based on the chronological hourly demand for Spain 2012 (40.4 GW-peak), the hourly solar production profile is also scaled from Spain 2012 data. The costs and technical characteristics of each power plant type are summarized in Table xii.

Table xii: Generating technologies characteristics[27]

	Max Output	**Min Output**	**Max Up Ramp**	**Max Down Ramp**	**Capital Cost**	C^{LV}	C^{NL}	C^{SD}	C^{SU}
	MW	MW	MW/min	MW/min	K$/MW-year	$/MWh	$/h	$	K$
OCGT	150	60	12	12	78.58	104	1650	-	14.75
CCGT	400	160	10	10	142.8	57	2440	-	28.33
NUCLEAR	1000	500	-	-	590.0	8.5	1500	-	-

C^{NSE} = 5000 $/MWh

Annex 4.B Pricing rules

4.B.1 Non-linear pricing rule: Marginal cost pricing

The general approach consist, as described in the introduction, in obtaining a uniform marginal price from the unit commitment model (marginal cost) and giving additional side-payments on a differentiated per unit basis. Side-payments are sometimes referred to as make-whole payments or uplifts. In practice, a side-payment is calculated as the

[27] These data is based on Black and Veatch (2012). The start-up costs take as reference Kumar et al. (2012).

difference between the incurred costs of a unit (according to its offer) and its uniform-price-based market remuneration. The difference generally considers the complete day costs and incomes (i.e. side-payments are calculated on a daily basis, not hourly) and only exists if the difference is positive (if costs happen to be higher than market remuneration).

$$\text{UniformPrice}_t = \rho_t \tag{4.12}$$

$$SP_{j,day} = \left[\sum_{t \in day} \underbrace{C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}} - \underbrace{\rho_t (\underline{P}_j u_{j,t} + p_{j,t})}_{\text{Market Remuneration}} \right]^+ \tag{4.13}$$

Where j denotes generating units and the production of each unit has been derived from the clustered production obtained in the UC model. Note this side-payment is only paid if positive and represents the payment needed when the uniform price ρ_t does not suffice to compensate for all the costs incurred in a day. Therefore, the income of each generating unit per day is:

$$\sum_{t \in day} \rho_t \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{4.14}$$

4.B.2 Linear pricing rule: Integer Relaxation

The pricing rule used as a representative example of linear pricing rules is generally referred to as "Dispatchable Model". It consists in a modification of the unit commitment model used for dispatch in which binary restrictions are relaxed. This way some units are partially committed and now, marginal costs depend on non-convex costs since an additional unit of energy would require an increase in the continuous commitment variable. Only equation (4.7) needs to be changed to:

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbf{R} \qquad \forall g \notin G^{MR}, t \tag{4.15}$$

The relaxed model is used only to compute prices. The new hourly price (ρ_t^{relax}) is the marginal cost of the relaxed UC solution. The feasible economic dispatch is still obtained from the unmodified unit commitment. The same procedure is used to calculate side-payments:

$$\text{UniformPrice}_t = \rho_t^{relax} \tag{4.16}$$

$$SP_{j,day} = \left[\sum_{t \in day} C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t} - \rho_t^{relax} (\underline{P}_j u_{j,t} + p_{j,t}) \right]^+ \tag{4.17}$$

Finally, the income of each generating unit per day in the linear pricing context is:

$$\sum_{t \in day} \rho_t^{relax} \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{4.18}$$

Note that the dispatch remains the same as in the non-linear case; the linear pricing rule only affects the remuneration by producing a higher uniform price through the dual variable of the relaxed problem which reduces side-payments requirements. This method does not recognize opportunity costs.

Annex 4.C Market-based mix search

To illustrate the methodology to find the perfectly adapted mix, first consider the following simple case with only two generation technologies. In order to determine how much capacity of each of the technologies will be installed, all possible combinations of technology one (T1) and technology two (T2) are represented in the plane shown in Figure 25.

If we focus on T1 only, the area of all possible combinations can be divided into a region of mixes that would make all units of T1 recover their capital cost (profitable) and a region where not all units of T1 recover their capital costs (not profitable). In the figure, region A + B represents the profitable area for T1. For a fixed level of T2, the boundary of the profitable area (break-even frontier) gives the capacity of T1 that would be installed since new investments would be made as long as these are profitable. No additional capacity would be installed beyond the boundary since these would not recover their investment costs or would make other units of T1 unprofitable bringing the total capacity installed back to the frontier.

The same reasoning applies to determine T2 capacity, which adapting to changes on T1 capacity and vice versa can only find equilibrium on the intersection of both break-even frontiers. Thus, the perfectly adapted mix can be obtained from the remuneration information calculated for each possible mix by modules 2 and 3 in our model. Note that these break-even frontiers will change under each of the pricing rules.

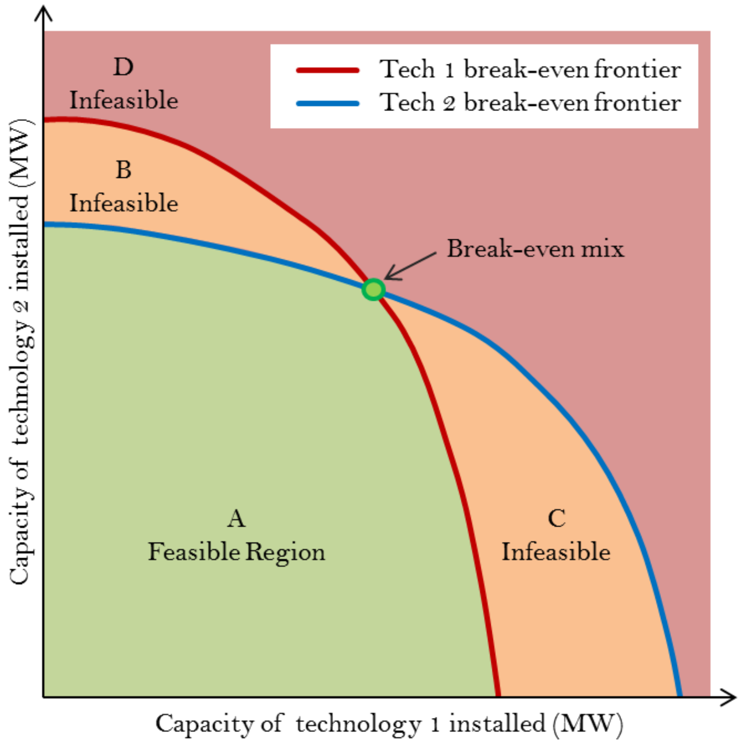


Figure 25. Continuous investment break-even mix

Figure 26 represents this methodology applied to a discrete investment problem, which is our case. Break-even frontiers can be interpolated from the point cloud and the continuous break-even mix obtained as the intersection. However, we are considering the more realistic discrete investments, which present a lumpiness problem. As illustrated in the figure, no point will probably coincide with the continuous break-even mix and various discrete energy mixes may seem valid under the break-even criteria. To discern which of these nearly optimal points is preferred, the value of the net market welfare resulting under each of the mixes is compared, and the mix minimizing the distance to the continuous break-even solution (measured in welfare) is selected.

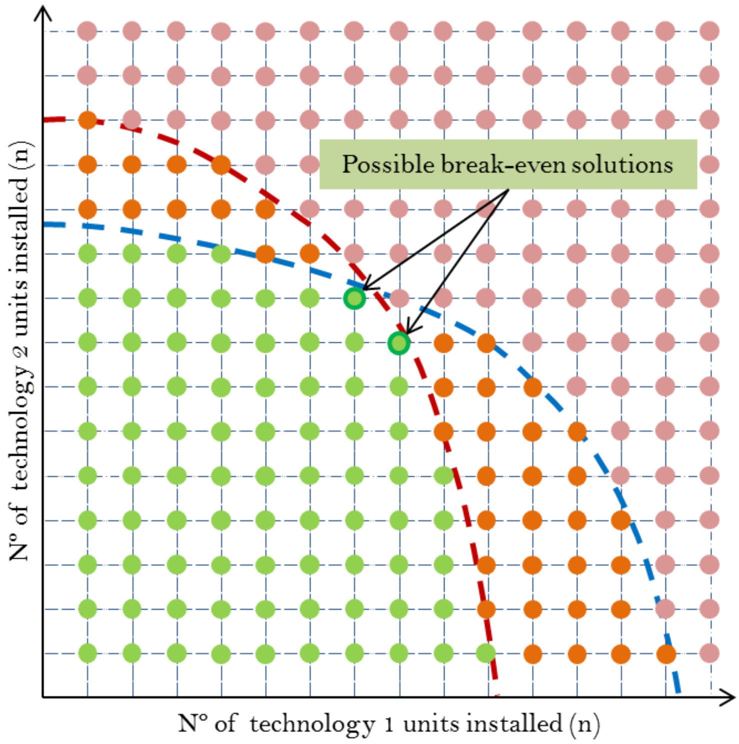


Figure 26. Break-even solutions

In our analysis, three technologies are considered (nuclear, combined cycle gas turbines and open cycle gas turbines), extending this illustrative example with a third dimension. Therefore, break-even frontiers become surfaces and these three surfaces (one for each technology) intersect at one point. An extension to *n* dimensions would be mathematically analogous although not easy to represent graphically.

5 BIDDING FORMATS

Electricity markets, especially in the short-term, are constrained by the physical reality of power systems. The ability of market agents to trade electricity is not only limited by grid constraints, but also by their own operational characteristics, which have to be considered when entering into supply contracts or participating in power auctions. Organized electricity markets, both in the US and Europe, feature different bidding formats to allow representing these constraints.

In recent years, power system operation has become increasingly complex by the introduction of renewable energy resources, and bidding formats need to be updated consequently. Furthermore, new market players are gradually entering into play, with new bidding requirements, such as storage resources and aggregators.

This chapter, learning from best practices, explores current and future challenges, and informs the necessary evolution of market designs with an especial focus on European markets, which is where more limitations have been identified in bidding formats. European markets could benefit from more resource-specific bidding formats (as in US markets), but further modifications are necessary in clearing algorithms to allow for this change.

5.1 Introduction

Organized electricity markets help participants manage their risks, while efficiently matching supply and demand, ideally contributing to the goal of maximizing market welfare. While electricity is often defined as a commodity (in the sense that one MWh of electricity is indistinguishable from another), experience has shown that for electricity markets to perform these tasks, they need to be far more complex than markets for any other commodity. The bidding formats used in both US and European electricity clearly reflect this fact.

In markets for most commodities, only the willingness to buy/sell is relevant, but in the case of electricity, the physical constraints of agents are equally important in determining its efficient allocation. Bidding formats are the parameters submitted by market agents as inputs for the clearing algorithm. These parameters express the willingness of the agent to buy or sell electricity, and the same time, they allow agents to represent their particular constraints (i.e., how it is physically capable to deliver as required by the market).

This chapter begins by describing how US and European markets allow market agents to represent their operational constraints (e.g., start-up, minimum power output, ramping constraints) in section 5.2. Then, section 5.3 discusses how the increasing penetration of renewable energy resources complicates the operation of power systems, and consequently, increases the need for complex bidding formats. This creates a need to improve current bidding formats, particularly in the European context. Section 5.4 analyzes performance issues and potential for improvement for current bidding formats. This analysis also includes other relevant discussions that influence bidding format design, and in particular, takes into account the relation with clearing and pricing rules (discussed in previous chapters). The conclusions (section 5.5) obtained in this chapter have a clear focus on European markets, the context where more issues have been identified.

5.2 Bidding formats: current practice

5.2.1 Markets in the United States

US markets use multi-part offers, which explicitly reflect generating units' operational (and opportunity) costs (such as start-up costs), and their technical constraints (e.g. ramp rates). Multi-part offers are clearly motivated by the market clearing approach adopted by ISOs, which is no other than the straightforward application of the Security Constrained Economic Dispatch (SCED) optimization models used before the liberalization of the power industry. Table xiii highlights the typical offer parameters that ISOs make available to thermal units.

Table xiii. Typical multi-part offer structure in ISO markets

Operating costs		Technical constraints	
Energy offer curve	MW, $/MW	Economic min	MW
Piecewise linear or stepwise linear function with multiple MW/Price pairs		Economic max	MW
		Ramp rate	MW/hour
No-load offer	$/hour	Min/Max run time	hours, min
		Min down time	hours, min
Start-up offer	$	Notification time	hours, min
Available for different types of start-ups (hot/ intermediate/ cold)		Cooling time	hours, min
		Start-up time	hours, min

In some cases, additional parameters allow multi-stage resources (combined cycle gas turbines) to represent their different operating regimes, and transition costs and constraints between modes. The bidding parameters highlighted here focus on the energy market, but US markets also optimize operating reserve provision, and other bidding parameters are provided to this end.

While the thermal-unit bidding format is the archetypical multi-part offer (this is the predominant type of generation in US systems), other bidding formats have also been implemented for different types of resources. For instance, section 5.4.1 describes recent developments to improve bidding formats available to pumped-storage hydro and other storage units. Not all market agents require complex multi-part offers, and it is possible to submit only price-quantity bids, which could be the case for renewable generators and load serving entities.

In summary, ISOs attempt to model the power system in the clearing algorithm with the highest detail possible, including the technical characteristics of each generator individually, apart from all the constraints required to ensure reliability. This complex model allows ISOs to optimally operate resources, while enabling competition in the provision of electricity and other services.

5.2.2 Markets in Europe

European power exchanges follow a completely different approach; their main goal is to provide a platform for market agents to trade electricity simplifying as much as possible the consideration of physical constraints, in an attempt to maximize market liquidity. System operation is decoupled from the market, and left to market agents and to transmission system operators, which eventually enforce reliability constraints. This vision shifts part of the responsibility in optimizing the operation of generation resources to market agents, and expects them to express their willingness to buy or sell power in a simpler way. For instance, most European power exchanges allow portfolio bidding, this is, generation companies that own a number of different generation units in the same area can submit combined offers, and then internally decide the operation of each unit to reach the required production.

The basic bidding format in Europe is the price-quantity pair; however, a set of more complex bidding formats is also available, as shown on Table xiv. Hourly step and linear piecewise orders resemble the variable cost component in US multipart offers, but in this case, all operational costs must be internalized in the offered price (no additional components such as the start-up cost are explicitly considered). Complex conditions can be added to hourly orders to reflect more sophisticated constraints. The minimum income condition available in the Iberian market can constraint the hourly orders of a unit, so they are only accepted if the income of the resource throughout the day reaches a fixed amount (representing, for example, the start-up cost) plus a variable cost component. The minimum income condition, combined with the load gradient condition, represents some but not all of the features of multi-part offers. However, the fixed and variable cost components are not considered for the maximization of market welfare, only to reject some hourly orders when the minimum income condition is not met.

Table xiv. Bidding formats in EUPHEMIA

Bid format	Description
Simple orders:	
Hourly step orders	Buy or sell orders for a given volume and a limit price. It can be partially accepted if the market clearing price is equal to the bid price.
Hourly linear piecewise order	Buy or sell order for a given volume and a pair of prices: An initial price at which the orders begins to be accepted and a final price at which the order is totally accepted.
Block orders:	
Regular block order	Buy or sell order for a single price and volume and a period of consecutive hours that can only be totally accepted.
Profile block order	Regular block order that can be partially accepted, it includes a minimum acceptance ratio condition.
Exclusive block orders	Set of block orders in which the sum of accepted ratios cannot exceed one.
Linked block orders	Set of block orders where the acceptance of some blocks (children) is conditioned to the acceptance of others (parents).
Flexible block order	Price and volume conbination that can be accepted in several consecutive periods within a defined delivery range.
Complex conditions:	
Minimum Income	Condition to reject all hourly orders of a resource if its daily remuneration does not reach the minimum income amount, defined by a fixed and a variable component.
Load gradient	Limit to the variation between the accepted volume at a period and the accepted volume at the adjacent periods

Alternatively, block orders are bids that apply to multiple consecutive periods simultaneously, instead of a single hourly period, and are accepted or rejected based on the average price for those periods. Resorting back to the example of the thermal unit, this could allow offering to start a power plant for a given set of hours, internalizing the start-up cost in the average price. Block orders can be combined using exclusive or linking conditions to represent more complex possibilities.

All order types in Table xiv are implemented in the single clearing algorithm EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm) (see EPEX SPOT et al., 2016). However, the orders available in each market area depends on the power exchange, aka Nominated Electricity Market Operator (NEMO), designated in a given country. The integration of power exchanges through the Price Coupling of Regions (PCR) initiative has achieved some standardization of market products, but for the moment, NEMOs have not fundamentally modified the orders available in their territory. For instance, complex conditions were, and still are, only available in the OMIE exchange (for Spain and Portugal), while Nord Pool (Nordic-Baltic region) and EPEX SPOT (central Europe) allow the use of block orders.

Bidding formats are regularly reviewed, with the latest proposal being submitted jointly by all NEMOs in November 2017 (NEMOs, 2017). The proposal did not include significant changes besides updating some definitions. For instance, hourly orders are now defined as Market Time Unit (MTU) orders, and any references to hourly periods have been modified accordingly; this is to allow changes in the definition of MTU in the future (the goal is to move from hourly to 15-minute periods). In addition, it generalized some definitions to allow the use of all orders as both supply and demand. For instance, the "maximum payment condition" was introduced as the demand-side version of the minimum income condition. These changes have not been implemented at the time of this writing.

5.3 The need for complex bidding formats

Bidding formats in both US and European markets reveal the higher complexity of electricity markets compared to other commodities. To describe some of the features of electricity that justify this complexity take the following example, comparing the efficiency of the day-ahead dispatch decisions that would result from using some of the previous bidding formats.

5.3.1 Variable costs

As a starting point, the simplest design possible is a single-period simple auction, where market agents submit price-quantity pairs to express their available production or desired consumption, and their production cost or demand utility. This is equivalent to only taking variable costs into account to dispatch the lowest-cost generators to supply demand. This design takes the assumption that producers' cost structure consists only of variable costs, which could be a reasonable proxy in power systems dominated by thermal power plants where variable costs are the most relevant cost component. This is the foundation of European power exchanges, and for instance, the Italian day-ahead market still uses only simple orders. Of course, this approach does not provide the most efficient, or even a feasible dispatch. Therefore, the Italian market (and European markets in general) rely on intraday markets that (among other relevant functions, see Chapter 6) rectify dispatch decisions.

5.3.2 Inter-temporal constraints

One of the reasons why this simple model can lead to inefficiencies is that, in the real multi-period problem, it cannot reflect constraints coupling different periods. For example, thermal power plants have ramping constraints that constraint the production available in one period by its production in the preceding and following periods. Dispatch efficiency could be improved incorporating ramping constraints in the optimization model (as in US markets, or using the load gradient condition), at the expense of some market transparency, but this is not the only way to face this problem. For instance, block orders allow bypassing this problem if used to offer a predefined production profile, as shown on Figure 27.

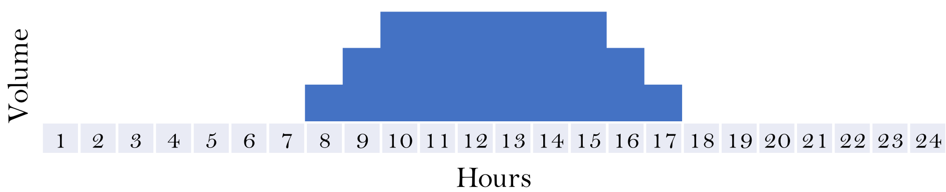


Figure 27. Simple block order representing a ramp-constrained production profile

5.3.3 Uncertainty

Using a block order requires the producer to take, prior to the market clearing, a decision about what would be the best production profile to offer into the market. The underlying assumption behind this simplification of the dispatch model is that producers can easily forecast market conditions (not only market prices, but also the resulting unit commitment), and offer the most efficient production profiles.

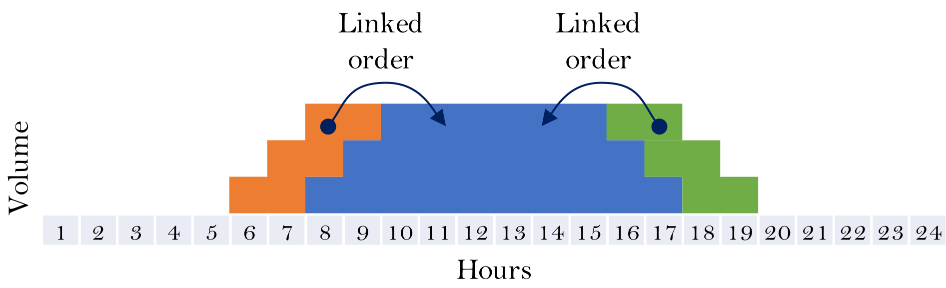


Figure 28. Linked block orders representing multiple possible production profiles

Linked and exclusive block orders can mitigate some of this uncertainty, allowing producers to express a wider range of potential operating profiles for the clearing algorithm to choose. For example, Figure 28 shows how two additional block orders (orange and green) can be linked to the previous order to potentially extend the range of hours where the unit is operating. Linked orders can only be accepted if the previous (parent) order is accepted.

The uncertainty associated to renewable production has greatly increased the need to model the complexities of power system operation. In US markets, this had no major impact on day-ahead bidding formats (Chapter 6 discusses the limitations of intraday scheduling), since multi-part bids already represent operational constraints with detail. In European markets, on the other hand, the use of block orders has increased significantly in recent years. Figure 29 shows[28] the average and maximum number of block orders used in the PCR region. Not only has the total number of block orders almost tripled from 2011 to 2017; the use of the most complex block types has had even greater growth.

[28] Data from European Stakeholder Committee of the Price Coupling of Regions (2016 and 2017). Only annually aggregated data was available for the period 2011-2013, and monthly for 2014-2017.

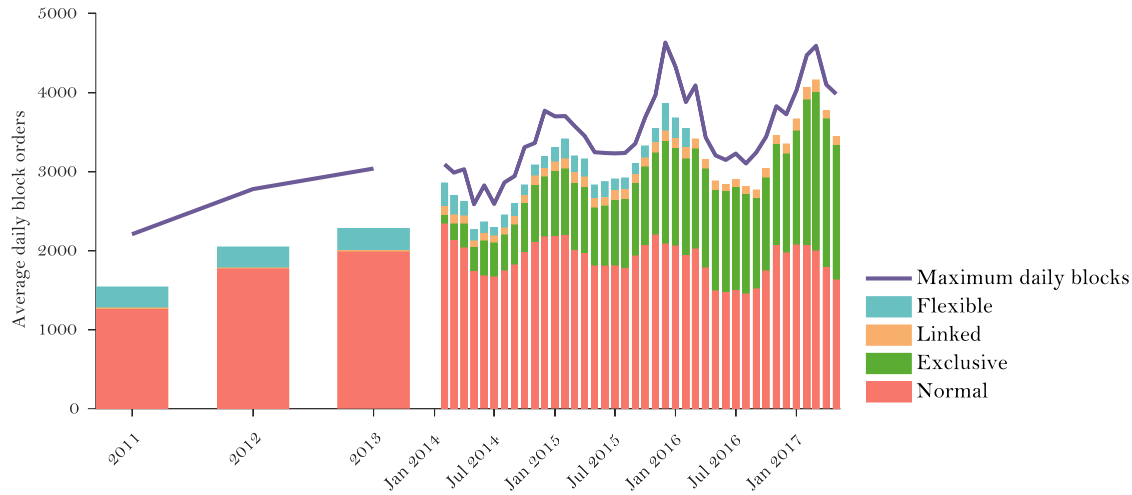


Figure 29. Average and maximum daily number of block orders in PCR region[29]

The use of exclusive orders remarks the fact that, in the uncertain context resulting from renewable production, producers cannot easily plan the operation of their units. Exclusive orders allow expressing multiple possible production profiles of which only one can be accepted by the market, therefore, it makes it easier for market agents to make offers for different scenarios. For example, the orders shown on Figure 28 express four different production profiles, which could also be represented by four exclusive orders. Exclusive orders can sometimes express a wider range of possibilities than linked orders, since exclusive orders do not need a common parent block. In the example in Figure 30, a unit does not know what is the best time to sell its production, so it offers three different blocks and the clearing algorithm will select the best one (maximizing market welfare) only.

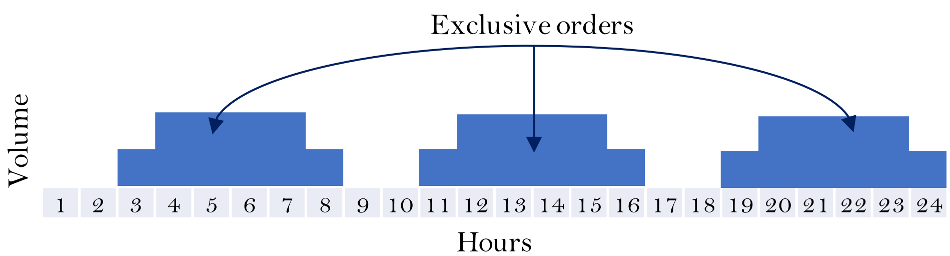


Figure 30. Exclusive block orders expressing multiple production profiles

5.3.4 Portfolio bidding

Power exchanges that allow block orders, also allow portfolio bidding. This improves the possibilities of a bidding format that may seem rather limited. The lack of complexity

[29] Flexible orders reported before March 2016 correspond to a definition phased out by Nord Pool (Flexible Hourly Block Order); no data was available for the new flexible orders.

can be compensated by managing a large portfolio, instead of an individual power plant. Large generation companies do not depend on the market-clearing algorithm to optimally operate their power plants, since a large portfolio allows “absorbing” potential inefficiencies. At the same time, this system has been favored by the fact that generation companies benefit from disclosing the minimum amount of information about their operating cost structures. However, limiting the amount of information contained in bids particularly hinders the participation of small producers, and makes it more difficult to monitor market power, since it is very difficult to link bid parameters to actual operating costs.

5.4 Discussions

5.4.1 New resources

The development of bidding formats has been clearly influenced by the needs of thermal power plants, not only in the US where multi-part bids are used; complex European bidding formats have also been tailored for the prevailing generating resources during the liberalization process. Furthermore, as described in previous sections, the current context of increasing (variable and uncertain) renewable penetration has resulted in a need for an even more detailed representation of the constraints of conventional (thermal and hydro) resources.

In the medium to long term, the transition to low-carbon power systems will reduce reliance on thermal resources, but other energy technologies will enter into play, since flexible dispatchable resources will be necessary to compensate for the variability and uncertainty of renewables. It is difficult to predict what resources will play that role in the future, but storage resources are a clear candidate. Pumped-hydro storage has been present in power systems for many decades, although with relatively little relevance. Still, for the same reasons that complicate the operations of thermal power plants, the participation of resources with (limited) storage capabilities now requires more complex bidding formats. The key challenge for storage resources is to decide in advance when to bid as a generator and when to bid as demand. This is especially difficult for new electro-chemical storage resources (such as Lithium-Ion batteries), because of their limited storage capacity. Grid-scale batteries, due to their high cost, are usually sized to store energy only for a few hours at nominal capacity, while pumped-hydro resources can have up to weekly or monthly planning cycles. Although both resources have limitations to participate in power markets with current bidding formats, small storage resources have attracted more attention during recent years.

Developments in US markets

In US markets, bidding formats are clearly resource-specific, which provides the most efficient bidding parameters for a selection of resources, but on the downside, discriminates potential new resources which cannot enter the market with ease until specific bidding formats are designed for them. For instance, pumped-hydro resources have participated in ISO for many years, but smaller storage resources (e.g., batteries, flywheels) have different constraints that cannot be represented with existing bidding formats. This created concerns that unnecessary barriers to storage resources were limiting competition, and the FERC initiated a consultation in November 2015, which culminated in Order 841 in February 2018, entitled "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators" (FERC, 2018).

This new rule requires, among other things, new bidding parameters specific to storage resources. As is usually the case, the FERC order allows a high degree of freedom for ISOs to customize rules to their specific context, so the required bidding parameters are a minimum standard, and ISOs can add new parameters on top of them. The requirements, summarized in Table xv, also provide an interesting judgement on what are the most relevant constraints of batteries.

Table xv. FERC-required bidding parameters for storage

Charging	**Discharging**	
Max charge limit	Max discharge limit	MW
Min charge limit	Min discharge limit	MW
Charge ramp rate	Discharge ramp rate	MW/min
Max charge time	Max run time	hours, min
Min charge time	Min run time	hours, min
Energy bid curve	Energy offer curve	MW, $/MW
State of charge constraints		
Initial state of charge		p.u.
Final state of charge		p.u.
Max state of charge		p.u.
Min state of charge		p.u.

The first characteristic that makes these bidding parameters different from traditional multi-part bids is that it allows for both charging (consuming) and discharging (generating) regimes, in a single bid. Before, storage resources needed to present separate offers as generators and consumers. The order also requires putting in place market rules to prevent conflicting dispatch signals in the same market interval (charging and discharging at the same time). This can be explicitly constrained in the dispatch model, but it is also possible to correct potentially conflicting supply offers and demand bids (making sure offers to sell are not lower than the price for bids to buy).

Although many of the bidding parameters are equivalent to the ones used in multi-part bids –maximum/minimum operating limits, ramp rates and maximum/minimum run times–, a new participation model is necessary because the constraints are applied simultaneously for charging and discharging. Furthermore, new constraints are necessary to represent the limited energy storage. The state of charge represents how much energy is stored in a battery with respect to its maximum capacity (0 if empty, 1 if full). Storage operators may need to limit the range of state of charge because battery to prevent excessive degradation of the battery. For example, battery manufacturers usually recommend keeping charge above a minimum threshold. Market agents could also use these parameters dynamically to manage battery charge to their needs. Finally, it is necessary to know the expected state of charge of the battery in the first period of the day-ahead market to perform the economic optimization. The state of charge can also be monitored during the real-time market so it can be continuously maintained within the desired limits. While the full set of bidding parameters would allow the ISO to optimize the state of charge of storage resources, the order is open to allow resources to self-manage their state of charge through their bidding strategy. In this case, resources would only submit some operational constraints to the ISO to ensure feasibility of the resulting schedule, but the optimization of the resource would result from its economic bids.

Developments in European markets

Arguably, the approach implemented in EU power exchanges provides a general set of "abstract" bidding formats that can be used by any type of resource. However, the market orders available have been progressively refined to meet the needs of market agents (mostly thermal resources), and the current design was not conceived for storage resources. As described for the US context, the main bidding requirement of storage resources is to represent the physical link between supply offers and demand bids. In this regard, linked block orders provide a limited way to represent this constraint. For example, as shown on Figure 31, a storage resource could submit a purchase block order and a linked sell block order. This way, the sell order will not be accepted if the purchase order has not been accepted as well. In other words, the battery will only be discharged if it has been charged before.

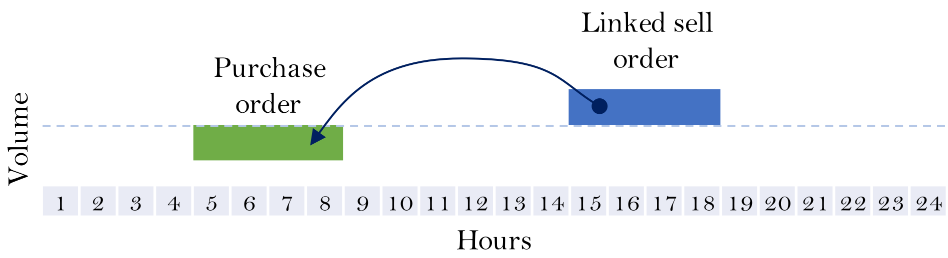


Figure 31. Use of linked block orders by storage resources

This use of linked orders has two main limitations for storage resources. First, market agents have to decide in advance two potential periods to buy and sell power, so the use of storage is not optimized. Flexible orders would do a better job at allocating the limited amount of energy available in the periods that maximize market welfare, but it is not possible to combined flexible and linked orders. It would also be beneficial to submit multiple pairs of linked buy-sell orders, including an exclusive constraint so only one of the pairs is accepted. However, linked and exclusive orders cannot be combined either.

Second, the linked order guarantees a feasible schedule (since the battery will not be discharged if it has not been charged before), but because the link can only go in one direction, the parent purchase order could be accepted without the sell order. This would produce a feasible but clearly suboptimal schedule, leaving the battery charged without a commitment to sell its energy. This creates a risk to incur losses if using this bidding format. Clearly, a solution would be to use linking constraints in both directions simultaneously, but this is not allowed for now. An alternative bidding format called "loop order" is in early stages of discussion by power exchanges, which would precisely allow submitting two mutually inclusive block orders.

5.4.2 Computational tractability

In both US and European market, the computational complexity of the clearing problem is an instrumental factor that conditions what bidding formats can be implemented in practice. US markets use market welfare maximizing optimization models to clear markets –which despite their large size are reasonably tractable problems–, followed by separate pricing models. European markets, despite including less detail in modeling the physical constraints of the system, combine clearing and pricing in a single more computationally complex model.

Challenges in US markets

As previously discussed, US markets use detailed multi-part bids, which capture most of the complexity of thermal generating units. This model is well prepared to face the introduction of larger shares of renewable production. ISOs have progressively increased the modeling detail in their markets (O'Neill et al., 2011), as made possible by optimization software improvements and developments in computing technology.

This does not mean the US model is not constrained by its computational tractability, but for the moment, computational improvements have continued to allow for incremental modeling enhancements. For instance, the previously described new bidding formats for storage have been successfully tested by various ISOs before the FERC order. However, computational problems could arise, not because of the complexity of these biding formats, but due to the larger number of participating resources. New storage resources could be 1 MW or less in size, which is orders of magnitude smaller than traditional resources, meaning the number of market participants could be hundreds of times the current amount. The size of the resulting dispatch problem could become intractable, and indeed, FERC Order 841 (FERC, 2018) included provisions to allow increasing the minimum bid size requirements:

> *We are also not concerned about the potential availability of software solutions as multiple RTOs/ISOs already provide a minimum size requirement of 100 kW for all resources and have not expressed similar concerns regarding the minimum size requirement. While establishing a minimum size requirement of 100 kW for the participation model for electric storage resources will result in some smaller resources entering the markets in the near term, we do not expect an immediate influx of these smaller resources or any resulting inability to model and dispatch them. However, we recognize this finding is based on the fact that there are currently fewer 100 kW resources than there may be in the future. Therefore, in the future, we will consider requests to increase the minimum size requirement to the extent an RTO/ISO can show that it is experiencing difficulty calculating efficient market results and there is not a viable software solution for improving such calculations.*

This computational problem in ISO markets results from the combination of two factors: complex bidding formats and the number of resources. Therefore, the scalability issue can be confronted from both sides. Increasing the minimum size requirement is a way to reduce the number of resources, but this also limits competition so it is only acceptable as a short-term solution. This measure should be accompanied by the development of rules for the participation of aggregations of resources, which opens all sorts of new questions. For instance, defining bidding parameters for aggregators cannot follow the usual resource-specific approach in ISO markets, since this participation model calls instead for general bidding parameters.

An alternative approach would be to simplify existing bidding formats. Just as creating participation models for aggregations rather than individual resources, this approach would reduce the ability of ISO markets to model the physical system accurately. Taking any of these solutions would significantly change the current *modus operandi* in ISO markets, but there are several reasons why ISO market will never need to simplify its approach all the way to European-like bidding formats. As already discussed, the welfare-maximizing clearing approach allows for much more complex bidding formats than the uniform-pricing clearing approach, now and in the future. Furthermore, ISOs have not shown interest in facing one of the greatest challenges of European markets (see next section), which is to integrate several states/countries in a continent-scale market. For now, each ISO market has a well-defined footprint, and although some of them are expanding their territory (for example, California ISO is "absorbing" some adjacent balancing authority areas), no plausible plans exist to integrate all North American ISOs. Such an objective in the future, however, would most likely require taking modeling simplifications.

Challenges in European markets

As discussed in Chapter 2, the uniform-price based clearing approach in European markets combines clearing and pricing in a single, more computationally complex problem. This computational complexity becomes especially relevant when considering the ultimate goal of European markets is to integrate all European member states in a single clearing algorithm. Computational problems have already surfaced during the first years of operation of the PCR, and Eastern-European markets are to join the common platform in the upcoming years. This size increase adds to the problematic trend in the number of block bids submitted to the market, which has increased as agents create complex combinations of different types of bids.

European power exchanges limit the amount of block orders submitted by portfolio (i.e., by market agent and market area), as shown on Table xvi. Note this approach does not limit the participation of small resources (as opposed to a minimum size requirement). However, the participation of more market agents could make it necessary to further reduce block order limits. Therefore, the regulation of aggregators is also in development in the European context.

Table xvi. Limits to block orders in main European power exchanges

	EPEX SPOT					NORDPOOL	
	DE/AT	FR	NL, BE	CH	UK	UK	NO, SE, FI EE, LV, LI
Block order							
Max. Volume (MW)	600	600	400	150	500	500	500
Max. Blocks/Portfolio	100	40	40	40	80	80	50
Regular/Profile	Reg	Reg	Reg	Reg	Reg	Pro	Pro
Linked block order							
Max. Levels	7	7	7	7	3	3	3
Max. Number of children	6	6	6	6	6	3	3
Max. Blocks in familiy	7	7	7	7	7	13	13
Max. Families/Portfolio	5	5	5	5	5		
Exclusive group block orders							
Max. Blocks in group	24	24	24	24	24	15	15
Max. Groups/Portfolio	5	5	5	5	18	3	3
Flexible orders							
Max. orders per portfolio						3	5

Source: EPEX SPOT (2018), Nord Pool (2017a), Nord Pool (2017b)

However, the computational tractability of the clearing algorithm is already a pressing issue, and more strict limits on block orders could be necessary to integrate more countries into the PCR. Furthermore, current rules require the clearing algorithm to obtain a solution in less than ten minutes, –a much more demanding timeline than US markets–, so a potential solution would be to allow additional time for the clearing process. However, European markets do not incorporate many physical constraints, making additional corrections by TSOs necessary, so it may not be possible to extend this timeline by a large margin.

Both reducing the number of block orders, and extending the time available to compute the solution, are temporary fixes. In the long term, it is necessary to focus on the root causes. The number of block orders submitted has greatly increased because no single bidding format properly addresses the needs of market agents, so agents combine orders in an effort hedge against all the possible market outcomes. Therefore, a more permanent alternative would be to create resource-specific bidding formats that would only require one (multi-part) bid per resource. However, since such resource-specific bidding formats would likely be more complex, they should be carefully designed to ensure they indeed reduce the number of orders, and overall problem complexity. A currently discussed alternative in this line is the introduction of thermal orders, which is nothing more than multi-part bids like the ones used in ISO markets.

The European Stakeholder Committee of the Price Coupling of Regions (2015) suggests that thermal orders can be preferable (from a computational efficiency point of view) if an agent can submit a single multi-part bid replacing multiple block orders. However, in the same stakeholder committee, the EUPHEMIA software provider (N-Side) has also pointed out that including such a bid would need to consider a significant change in the market design and pricing and clearing rules, which are discussed in the next section.

5.4.3 Clearing and pricing rules

Pricing and clearing rules have already been discussed in previous chapters, so this section only clarifies how they are related to bidding formats. Previous discussions of pricing rules focused on the US (multi-part bid) context, but the same essential challenges arise in European markets, so this section focuses on the European context. As already discussed, even if European bidding formats are supposed to be simpler, they also represent non-convexities, having similar implications. Take for example start-up costs, European bidding formats do not allow represent these cost as explicitly as US multi-part bids, but in both cases market agents can resort to market orders in a way that should, at least, guarantee operational costs are recovered.

For instance, the minimum income condition is quite close to representing start-up costs. This constraint guarantees that the offers of a unit will only be accepted if the price is high enough to compensate a given fixed cost (representing the start-up cost). Although this fixed cost influences the clearing of the market –triggering the rejection of the offer if the price is not high enough–, it does not directly set the market price (same as start-up costs in US markets), which is always set by a simple (marginal) bid.

Something similar happens with block orders, which cannot set the market price either. Note that, even if uniform prices necessarily include all operational costs, there is a nuanced difference between market prices being high enough to cover costs, and market prices being reflective of system costs. This is in essence the same problem described for US markets, where inflexible units could not set the price; fortunately, this also means that European markets could benefit from the same solutions. However, the only way to allow alternative pricing rules is to modify clearing rules as well.

Clearing rules in European markets are based on uniform pricing, but this is not imposed by bidding formats. Even though market orders always express their constraints with respect to market prices (i.e., if price is below X, reject order), the uniform-price clearing approach is mostly the result of a market that has evolved from a simple auction. As previously stated, the basic information contained in market orders is the necessary remuneration, but said remuneration could include uplift payments if such a policy choice was made. Obviously, this requires a significant change, but current bidding formats do not prevent using a market welfare-maximization clearing approach and an alternative pricing rule.

Indeed, a welfare-maximization clearing approach would greatly simplify the clearing algorithm, helping European markets cope with the current increase in the use of block orders. Also, it would enable more complex bidding formats, such as thermal orders; and more complex combinations of block orders, as made necessary by storage resources. The disadvantage of such as clearing approach is that it requires the definition of pricing rules, this challenge has already been discussed in previous chapters, and developments in this field make it possible to be optimistic that the gains of such an approach would overcome the unavoidable drawbacks.

5.5 Conclusions

The penetration of renewable energy resources has significantly altered power systems. In light of these changes, wholesale electricity markets, and in particular day-ahead markets, in their role to facilitate planning and operating decisions, require increasingly complex bidding formats. While US markets already provide detailed multi-part bids to reflect the most relevant constraints of thermal generators, European markets provide a limited choice of block orders and complex conditions. These orders may be falling short to facilitate an efficient participation of all resources into electricity markets, as evidenced by the ever more complex combinations of orders submitted by market agents to achieve an adequate representation of their constraints.

The energy transition will also bring about the introduction of new energy resources, for example batteries and other types of storage, making it necessary to address their needs and remove barriers for effective competition. The definition of participation models for storage is underway in US markets, but European markets lack specific bidding formats for this type of resources. Although European markets use general bidding formats that should not discriminate any resource (they are limited, but should be equally limited for all types of resources), storage resources face significant barriers.

Since most difficulties have been identified in the European context, this is where the following conclusions focus. Regarding the limits of current bidding formats to represent both thermal and storage resources, a potential solution is to increase the range and complexity of the orders available. However, European markets are already facing computational difficulties, and this approach would most likely fall into scalability issues.

Therefore, the most sustainable approach in the long term would need to both reduce the computational complexity of the clearing problem, and allow more complex bidding formats. This may seem an impossible puzzle, but there are ways in which it can be achieved. First, resource-specific bidding formats, similar to US multi-part bids, can in some cases reduce the computational burden if one multi-part bid substitutes a complex combination of block orders. At the same time, resource-specific bidding formats would remove barriers for small market players (current portfolio bidding is advantageous for large players), and facilitate market monitoring.

However, the primary cause for the limitations of European bidding formats is the clearing approach. European markets are based on uniform prices; clearing the market under uniform-pricing constraints complicates the computation of market programs, so the range of bidding formats available is limited to keep the computational burden under control. Alternatively, US markets use computationally simpler clearing algorithms based on the maximization of market welfare (without pricing constraints). As reviewed in previous chapters, this approach requires an ex-post price computation, with its own challenges, but it would enable the use of increasingly necessary complex bidding formats in the European context.

In conclusion, resource-specific bidding formats are most advantageous, especially when combined with welfare-maximization clearing rules. However, their design has to be regularly reviewed to ensure no resources are discriminated. This is especially challenging when considering future potential energy resources, of which their technical characteristics are yet unknown. Nonetheless, this cannot be strictly considered a disadvantage over European (resource-independent) bidding formats, since these are equally influenced by current resource needs, and also become outdated. The resource-independence of European bidding formats cannot be unequivocally considered a positive feature, unless full generality is achieved (which is not the case). For instance, they present several limitations to represent the constraints of storage resources.

References

EPEX SPOT, 2018. EPEX SPOT Operational Rules, version 008. Available at www.epexspot.com. January 1, 2018.

EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, TGE, 2016. EUPHEMIA Public Description, PCR Market Coupling Algorithm. Version 1.5, December 2016.

European Stakeholder Committee of the Price Coupling of Regions, 2016. PCR Stakeholder Forum, January 2016.

European Stakeholder Committee of the Price Coupling of Regions, 2017. PCR Status Update, June 2017.

European Stakeholder Committee of the Price Coupling of Regions, 2015. Euphemia Performance, September 2015.

FERC, 2018. Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. Order No. 841, 162 FERC 61,127. February 15, 2018.

NEMOs, 2017. All NEMOs' proposal for products that can be taken into account by NEMOs in single day-ahead process in accordance with Article 40 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management. November 13, 2017. Available at: www.europex.org/all-nemos

Nord Pool, 2017a. Product Specification Nordic, Baltic and German market areas. Available at www.nordpoolgroup.com. July 3, 2017.

Nord Pool, 2017b. Product Specifications GB Market. Available at www.nordpoolgroup.com. August 15, 2017.

O'Neill, R.P., Dautel, T., Krall, E., 2011. Recent ISO software enhancements and future software and modeling plans. Available at https://www.ferc.gov/industries/electric/indus-act/rto/rto-iso-soft-2011.pdf.

6 INTRADAY PRICE SIGNALS

Efficient operation of power systems increasingly requires accurate forecasting of load and variable energy resources (VER) production, in order to mitigate the need for and costs of flexible resources, capable of adapting to changing conditions in the intraday horizon. This chapter examines the benefits of cost reflective intraday price signals, and in particular, proposes modifications to the current design of US ISO markets, where the existing two-settlement (day-ahead and real-time) system does not allow for cost reflective intraday settlements.

The proposed scheme produces intraday price signals via a "multi-settlement system", which entails computing market prices and executing additional settlements when intraday schedule changes are made. Pricing and uplift allocation rules are developed to test the multi-settlement system in an illustrative case example. This allows to demonstrate the benefits of the proposed system, but also additional insights on the interaction between pricing rules and intraday markets in both the US and European context.

6.1 Introduction

Within the very diverse timescale of wholesale electricity markets –from years-ahead long-term markets, to the very short-term balancing and regulation markets–, the day-ahead market (DAM) has traditionally played the leading role in determining the economic dispatch. However, as Variable Energy Resources (VER) achieve relevant shares, the growing uncertainty after DAM production schedules are cleared is increasing the need to refine the design of shorter-term markets.

In the European context, intraday markets have proven to be critical in accommodating large amounts of solar and wind production (Borggrefe and Neuhoff, 2011); the reason being that VER forecast accuracy is significantly higher a few hours before real-time (when intraday markets take place), than a day or over before, when the day-ahead market is cleared. Multiple intertemporal constraints in power systems make the cost derived from forecast errors quite substantial, especially in systems that cannot rely on abundant storage capability, such as hydro-reservoir generation. This requires forecast errors be corrected as soon as possible to minimize the cost of rescheduling units (Mc Garrigle and Leahy, 2015); the sooner the market or ultimately the System Operator is aware of the need to modify the day-ahead market schedule, the lower the costs for redispatching.

In the EU context, rescheduling cost is mitigated by intraday markets in two ways. First, intraday markets that cover a wide range of timescales allow VER to gradually correct their programs, thus reducing the impact of their forecast errors on the overall cost of the system. Second, intraday markets produce intraday price signals that reflect the cost of making these corrections at different points in time. Intraday prices serve to efficiently allocate rescheduling costs to the units responsible for such adjustments, creating a significant incentive for renewable generators to improve their prediction procedures and to rectify forecast errors as soon as possible (Klessmann et al., 2008); and to properly reward the units capable of rebalancing the system, attracting flexible resources.

The markets run by the Independent System Operators (ISOs) in the United States follow a different approach, which does not present the same positive characteristics. ISOs run intraday commitment processes that allow for gradual forecast corrections. However, these intraday commitments do not automatically result in price signals for market participants. A "two-settlement system" is implemented, which settles all deviations from the day-ahead program at the same real-time price, regardless of when (how in advance) and at which specific cost each deviation was corrected (Helman et al., 2008). Therefore, the North American design does not provide market agents with the increasingly necessary incentive to improve their forecasts, as it is the case in European intraday markets[30]. A centralized dispatch approach can have significant advantages with respect to the European model (for instance, it mitigates the negative impact of information asymmetries), but the two-settlement system lacks the more granular signal provided by intraday prices. This traditionally ignored fact is becoming clearer due to the penetration of variable energy resources, and the expected entrance of distributed energy resources; and more authors now acknowledge this shortcoming of US markets,

[30] Usually, ISOs take charge of the forecasting of renewable generation but, as reviewed in section 6.2.2, they are increasingly taking actions to incentivize VER to submit their own forecast.

which *"could be improved by introducing intraday price signals that would aid the participation of distributed resources"* (IEA, 2016).

This chapter proposes an alternative settlement system to bring about the benefits of intraday price signals (see section 6.2) to US markets with minimal implementation costs, and maintaining the centralized role of ISOs. At the same time, this discussion builds a better understanding of the implications of intraday settlements in a market characterized by a centralized dispatch logic and a non-uniform pricing approach. This can provide valuable insights for a hypothetical introduction of optimal-dispatch based clearing algorithm in European markets.

Section 6.3 describes how US markets could move from the two-settlement system to a "multi-settlement" system, computing a settlement for each intraday commitment process run by the ISO. To introduce intraday settlements successfully, price and uplift computation rules must be consistent across the entire sequence of markets. A simplified uplift computation and allocation rule is proposed and tested in section 6.4, using a simulation model to illustrate the benefits derived from the economic signals that arose from the multi-settlement system.

6.2 Background

6.2.1 The European approach

European Member States have achieved different levels of harmonization in the design of their short-term electricity markets: day-ahead markets are coordinated through the Price Coupling of Regions initiative (EPEX SPOT et al., 2016); while a common and coordinated design for intraday markets is still, at the time of this writing, under discussion (European Commission, 2015a). Currently, all EU Power Exchanges (PX) allow intraday trading, based on several successive auctions or on continuous trading mechanisms (Neuhoff et al., 2015). Either way, the purpose of intraday markets is in essence not different from the DAM, for they are forward electricity markets that take place some hours or minutes ahead of real-time instead of one day-ahead. All agents (generation and demand) can bid in day-ahead and intraday markets to update their financially binding schedule. The Transmission System Operator (TSO) subsequently incorporates reliability constraints and provides physical programs, taking charge of final adjustments at the balancing market, where the TSO acts as a central counterparty to settle all deviations from previous schedules. This process is summarized in Figure 32, which also illustrates the separation between PXs and TSOs.

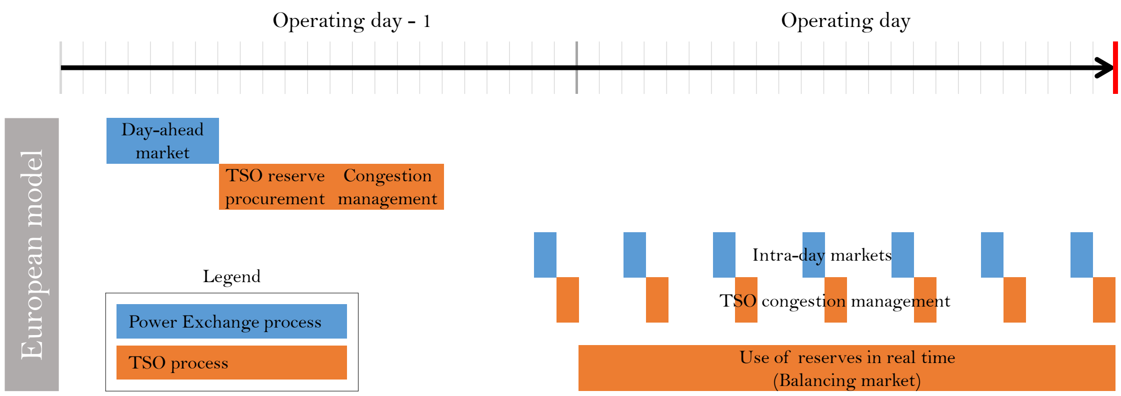


Figure 32. European markets simplified timeline

As clearly stated by the European Commission (2015b) in a recent public consultation document: "*Short-term markets, notably intraday and balancing markets, must be at the core of an efficient electricity market design.*" The importance of intraday markets stems from the need to reflect changing conditions in system operation after the day-ahead market. Through intraday trades, agents can correct their positions if they obtain new information (i.e., an improved forecast), and deviations are priced reflecting the cost of solving such imbalance at the time it is foreseen. This incentivizes agents to find the most cost-efficient way to minimize and solve their imbalances, which generally means buying/selling the deviation energy as early as possible. Essentially, intraday trading is a market-based tool to allocate re-scheduling costs per cost-causality.

The key role of intraday markets in accommodating renewable uncertainty is eloquently supported by European regulators in the joint ACER-CEER (2015) response to the above-mentioned consultation: "*RES (Renewable Energy Sources)-based generation forecasts are only reliable very close to real-time. It is, therefore, crucial that RES-based generators can access well-functioning short-term markets in which to sell their electricity output and to balance their positions or support system balancing.*" This response makes another very relevant point: "*balancing responsibility should apply to all generators above a certain size in order to incentivise all market participants to undertake thorough scheduling and forecasting. Independently from the existence of support schemes, all RES-based electricity should be included in a balancing perimeter.*"

The two citations highlighted above point towards two important ingredients for VER integration that can be provided by intraday markets: (i) short-term opportunities to correct forecast errors at different times progressively closer to delivery, and (ii) economic signals that reflect imbalance costs to incentivize forecast accuracy.

The European experience with intraday markets has indeed been satisfactory to integrate renewable production, and is largely responsible for the improvement in forecast accuracy witnessed in European power systems[31]. Take for example the case of Spain, where wind generators have been imbalance responsible since 2004. As illustrated in Figure 33, wind forecast errors have continuously decreased due to forecasting tools enhancements.

[31] See for example (Batlle et al., 2012), (Eurelectric, 2010).

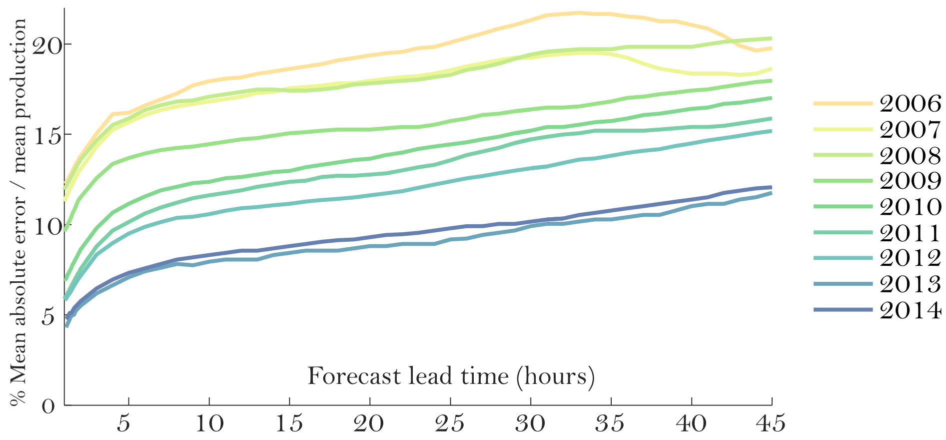


Figure 33. Wind forecast error evolution in Spain[32]

6.2.2 The US ISO approach

Spot electricity markets in the US are built around the previously mentioned two-settlement concept, which refers to the day-ahead and the real-time market settlements. The day-ahead market can be considered *"a forward market subject to all the physical and reliability power system constraints that are known at the time to affect the next-day (real-time) dispatch"* (Helman et al., 2008), so it has a similar role to the one in European PXs. However, because in the US there is no institutional separation between market and system operation, the DAM –while remaining a financial market– represents the physical reality with a much higher level of detail. Day-ahead markets in the US are cleared via a so-called Security Constrained Unit Commitment and Economic Dispatch (SCUC/SCED) optimization model considering the physical constraints of generators and the transmission system.

While load serving entities and renewable energy producers can bid in the day-ahead market, the ISO replaces those bids by its own forecasts thereupon. The second settlement corresponds to the real-time market (RTM). The real-time market resembles the day-ahead market in the characteristics of the SCED model employed, but it is not run in a single process, instead, it consists of various runs throughout the day. Each SCED run produces dispatch instructions only a few minutes before each period (typically, five minute periods). RTM prices capture the marginal cost of generation dispatch when final system conditions are known, and are used to settle all differences between day-ahead schedules and real-time (five-minute) schedules.

[32] Source: Red Eléctrica de España (REE)

Last-minute dispatch instructions from the SCED software can only make relatively small schedule changes, so the ISO has additional tools to make more significant modifications (essentially, to commit additional units) longer in advance. These tools – referred to in this Thesis as intraday commitment processes[33] (ICPs), in contrast with the real-time dispatch–, are important to efficiently adapt schedules to changes in forecasted load or system contingencies; and more recently, intraday commitments also have a key role in integrating the growing share of renewable production. In this regard, ICPs bear a slight resemblance to European intraday markets in that they are the main means to make relatively large schedule changes in response to new information.

As already mentioned, not all agents' bids are considered in ICPs and the RTM. This approach was originally adopted because, given the low engagement of the demand side of the market, there was no point in obtaining updated load forecasts from load serving entities after the day-ahead market. Therefore, no financial incentives were designed for market agents to provide updated information to the ISO: ICPs do not produce financially binding prices and therefore, do not perform the functions of a forward market (i.e. do not allow risk hedging and do not provide any economic incentive)[34]. This system does not recognize that renewable generation has completely different characteristics from load.

Opportunities for improvement in the US context

The downside of the US approach is that it mutes price signals that could incent the use of renewable production forecasts directly provided by producers, which can better account for local conditions. As discussed in section 6.2.1, ample evidence suggests that producers can significantly improve their forecasting accuracy when faced with cost reflecting signals. Recently, FERC Order 764 acknowledged this potential value by requiring "*interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting*" (FERC, 2012).

[33] These processes are frequently called Reliability Unit Commitments (RUC), but RUC often refers only to the first commitment process after the day-ahead market, so to avoid confusion we introduce the more general term "intraday commitment process".

[34] Bilateral markets, if sufficiently liquid, can partially mitigate the lack of intraday markets but are generally less efficient than a centralized market in coordinating resources.

CAISO is leading VER integration efforts, and it implemented a fifteen-minute market (FMM) where VER producers can provide their own forecast, updated every 15-minutes (CAISO, 2013). This initiative motivates, and has some similarities with, the proposed multi-settlement system. The FMM produces financially binding prices, and therefore allows buying/selling deviations from the day-ahead market at the FMM price. This approach successfully provides incentives to submit timely and accurate forecasts to the FMM, although our proposal aims at extending these settlements to all intraday commitment processes.

For the moment, it is optional for VER owners to provide their own forecast in the FMM. Therefore, two (potentially) different forecasts coexist in the FMM. While the forecast provided by VER owners is always the one used for settlement, the ISO may choose to use its own forecast when solving the dispatch problem (which is what determines FMM prices). In the context of our proposal, this approach can serve as a transitory regime to allow market agents to participate progressively in intraday settlements and gain confidence on the benefits of the system before it is fully implemented. Finally, the FMM price is not binding for load serving entities, since the ISO uses its own load forecast in this process. This proposal envisions intraday settlements involving all market agents.

The focus of the case study presented next focuses on VER production forecasts, but other information can also be critical to take efficient commitment decisions. Several ISOs are reviewing their bidding protocols to allow thermal generating units more flexibility in updating their bids after the day-ahead market. Essentially, the general goal is the same as with VER production forecasts: to incorporate updated information from market participants in the intraday horizon.

The generators that most commonly need to update their offers in real-time are gas-powered units, which need to reflect price changes in intraday gas markets, especially during gas scarcity situations. Otherwise, thermal units can be scheduled uneconomically requiring after-the-fact compensations. Tariff changes have recently been accepted to address this issue in ISO-NE (ISO-NE & NE Power Pool, 2014), in CAISO (2016), or in PJM (2017). In this regard, this proposal can help align financial incentives with the need to receive continuously updated data from generators.

6.3 Multi-settlement system: Implementation challenges

This section describes the proposed multi-settlement system for ISO markets, which tackles the shortcomings described on section 6.2.2 while maintaining the fundamental characteristics of the North American designs, e.g. without the need to decouple market and system operation as in the EU context. The key objective is to provide a proper allocation of intraday rescheduling costs, and to send efficient signals to market agents to do their best to forecast their production programs, a key factor considering the increasing penetration of renewables.

The philosophy of the multi-settlement system is for each intraday commitment process to be followed by its corresponding pricing and settlement procedure, based on the marginal cost of the dispatch problem, as it is done in the day-ahead forward market. Because the additional settlements can be performed from the results of existing ICPs, the multi-settlement system does not entail an additional computational burden. Agents are encouraged to continuously submit their most updated production forecasts, which are used by the ISO to update commitment and dispatch instructions at a cost that can be allocated to forecast deviations charging the marginal cost of the required dispatch correction. This incentivizes producers to submit the most accurate forecast possible when each intraday commitment is performed.

This system takes from the European approach the concept of intraday price signals, which as stated have proven to be an efficient way to allocate imbalance cost following cost causality and have had a key incentive effect to improve forecast accuracy. At the same time, this system maintains the centralized dispatch approach of the US. Essentially, extending the existing two-settlement system into a multi-settlement system. Implementing this extension in practice requires some other market design elements to be defined or reexamined. The following sections discuss the frequency of intraday reschedules, the definition of pricing rules (especially, the computation of uplift charges), and the role of virtual bids.

6.3.1 Timing of intraday settlements

The optimal timing of each intraday settlement (essentially, the optimal frequency to reschedule resources) depends on the specifics of each power system. The frequency of the intraday commitment processes in place in each ISO should already reflect these tradeoffs, and provides the best guideline for implementing the multi-settlement system; intraday settlements should produce financially binding prices and schedules immediately after each ICP. As shown in Table xvii, ISOs have implemented slightly different designs for their ICPs. The table includes the denomination of each of the scheduling procedures after the day-ahead market (including the real-time dispatch), with which frequency and look-ahead horizon it is executed, and whether it produces binding commitment or dispatch instructions, and financially binding prices.

Table xvii. ISO's intraday timeline summary

ISO	Procedure	Frequency	Look-ahead	Commitment	Dispatch	Prices[a]
CAISO	Residual unit commitment (RUC)	Daily	24-168 h	Long start units		√[b]
	Short-term unit commitment (STUC)	1 h	4 h	Medium/short start		
	Real-time unit commitment and FMM	15 min	60-105 min	Fast start units	√	√
	Real-time economic dispatch	5 min	Up to 60 min		√	√
ISO-NE	Resource Adequacy Analysis (RAA)	Daily	Oper. day	Non-fast start units		
	Additional RAAs	As needed	Oper. day	√		
	Unit dispatch software	5 min	60 min		√	Ex-post
MISO	Reliability Assessment Commitment (RAC)	Daily	Oper. day	√		
	Intraday RAC	As needed	Oper. day	√		
	Look-ahead commitment (LAC)	15 min	3 h	√		
	Real-time SCED	5 min	N/A		√	Ex-post
NYISO	Supplemental resource evaluation (SRE)	As needed	Oper. day	√		
	Real-time commitment (RTC)	15 min	150 min	√		
	Real-time dispatch (RTD)	5 min	60 min		√	√
PJM	Reliability Assessment Commitment (RAC)	Daily	Oper. day	√		
	Combustion Turbine Optimizer (CTO)	As needed	Oper. day	√		
	Ancillary Service Optimizer (ASO)	1 h	60 min	√		
	Intermediate-term SCED	15 min	60-120 min	√		
	Real-time SCED	5 min	15 min		√	√
ERCOT	Day-ahead Reliability Unit Commitment	Daily	Oper. day	√		
	Hourly RUC	1 h	Oper. day	√		
	SCED	5 min	N/A		√	√

Sources: FERC 2014a § III.C; CAISO 2015a § 6.7, 7.5-7.8; ISO-NE 2014; MISO 2015a § 40.1, 40.1.A, 40.2; MISO 2015b § 6; NYISO 2013 § 8.4; NYISO 2015 § 4.2.3.1, 4.4.1, 4.4.2; PJM 2013a b; PJM 2015a § 2.5, 2.7; PJM 2016 § IV.1; ERCOT 2015 § 5.2, 6.2

[a] In some ISOs the real-time price is determined ex-post from metered outputs instead of ex-ante from the optimal dispatch.

[b] CAISO's RUC price is not for energy ($/MWh) but for capacity ($/MW/h) that guarantees being available for dispatching in the real-time market.

The reason for the different designs implemented by each ISO can be mostly explained by the reigning generation mix in each of the systems, which influences other considerations such as implementation costs and benefits. For example, CAISO, with significant VER penetration (to US standards), presents probably the most sophisticated design; it uses separate commitment processes for power plants with different start-up times. Possibly, other ISOs will follow this trend to integrate larger shares of intermittent generation, take as an example one of the recommendations of the PJM Renewable Integration Study (GE Energy Consulting, 2014):

> *"PJM's present practice is to commit most generation resources in the day-ahead forward market, and only commit combustion-turbine resources in the real-time market to make up for the normally small differences from the day-ahead forecast. When higher levels of renewable generation increase the levels of uncertainty in day-ahead forecasts, the present practice could lead to increased CT usage, in some cases for long periods of time where day-ahead wind and solar forecasts were off for many consecutive hours. In such circumstances, it would be more economical to commit other more efficient units, such as combined cycle plants that could be started in a few hours."*

These criteria remain valid for the timing of intraday settlements. It can be cost efficient to implement more frequent intraday settlements (and their corresponding commitment processes), if it is necessary to make more frequent dispatch corrections; and it will not be cost efficient otherwise. For this reason, it is unlikely that any ISO will find it necessary to implement intraday settlements with a frequency beyond 15 minutes, given that it would get in a timeline that is already covered by the real-time settlement.

6.3.2 Pricing in the multi-settlement system

Pricing and uplift computation rules need to be defined for the additional intraday settlements, this section discusses those rules and their interaction with day-ahead and real-time markets

Price formation

As described in previous chapters, in electricity markets with multi-part bids (representing non-convex generation cost functions) marginal cost pricing fails to fully reflect operating costs. ISO markets increasingly rely on alternative pricing methods that go beyond traditional marginal cost pricing to obtain more cost reflective prices. These pricing methods are different from one ISO to another; furthermore, ISOs often use different pricing methods in their day-ahead and real-time settlements. Where most ISOs coincide is in including some type of "fast-start pricing". Although the focus of this chapter is not on pricing rules, the implementation of multiple intraday settlements hints at some desirable properties of pricing rules. For instance, using the same price computation method in day-ahead, intraday and real-time settlements is necessary to avoid inconsistencies in price formation. Such inconsistencies already exist between day-ahead and real-time markets, indeed, FERC (2016) proposes to *"incorporate fast-start pricing in both the day-ahead and real-time markets"*. However, in a multi-settlement system this matter becomes critical since the higher frequency of the settlements would aggravate inconsistencies in price formation. One of the reasons why some ISOs consider fast-start pricing unnecessary in day-ahead markets, is the relatively small impact it would have, since usually, fast-start units are only committed in the real-time market. With a multi-settlement system, some intraday commitments would include fast-start units, making fast-start pricing necessary as well in the intraday timeframe.

In the following case example, the same pricing rule is used in all the settlements simulated, and follows the latest recommendations from FERC (2016). The pricing run uses the Integer Relaxation approach for fast-start units: it relaxes binary variables for committed fast-start units, and fixes commitment variables to zero for uncommitted units.

Uplift computation

In addition to whichever pricing approach is implemented, ISOs complement generators' market remuneration through uplift credits (aka side-payments or make-whole payments) to compensate operational costs not recovered through marginal prices. These are typically start-up and no-load costs, but variable cost recovery may need make-whole payments as well in some cases. The exact methodology used to compute uplifts differs from one ISO to another and is subject to clauses of different nature[35]. Therefore, the uplift computation and allocation rules used in this paper (briefly described in this section and further developed in Annex 6.C) are general, and should be further developed and refined for its implementation in a market.

Uplift computation can be broken down into three parts. First, defining which costs are eligible for uplift compensation; second, computing uplift credits based on what eligible

[35] For the detailed description, refer to CAISO 2015b § 11.8; ISO-NE 2015 § III.F.2.1-III.F.2.2; MISO 2015c § B.12, D.15; NYISO 2014 § Appendix E; PJM 2015b § 5.2.1; ERCOT 2015 § 4.6.2.3, 5.7.1, 6.6.3.7.

costs were not offset by market revenues; and lastly, allocating the resulting uplift charges.

Defining eligible costs also requires assigning those costs to a settlement, for example, if a unit is committed in the day-ahead market, its start-up cost would be assigned to the day-ahead settlement. This has later consequences for uplift allocation. Also, only costs that are incurred by following ISO instructions are eligible, so if the start-up instruction is cancelled by the ISO after the day-ahead market, its cost is no longer eligible.

Uplift credits are determined as the shortfall between market revenues and eligible costs. In the two-settlement system, shortfalls are computed separately for the day-ahead and real-time markets. For example, a generator could receive an uplift credit because of a shortfall between day-ahead eligible (i.e., incurred in real-time) costs and day-ahead revenues, and then earn an additional profit in the real-time market without losing any of the day-ahead uplift credit[36]. The separation between day-ahead and real-time uplift credits is aimed at retaining an incentive for generators to bid in the real-time market; if the real-time market revenue was used to net day-ahead costs, the generator might be unable to make any profit in the real-time market. However, some argue (see for example Monitoring Analytics, LLC, 2016) that it would be preferable to net all revenues (day-ahead and real-time) with all costs to reduce total uplift costs (at the expense of this desired incentive), especially given current concerns about excessive uplift costs. The uplift netting discussion is relevant for the multi-settlement system, since computing separate uplift credits in the additional intraday settlements would further increase uplift payments. Therefore, this proposal considers two alternative mechanisms to compute uplift credits.

- The first possibility (no uplift netting) is developed as an extension of the two-settlement system, and therefore computes separate uplift credits for each of the intraday settlements. This option increases uplift charges, but also allows a cost reflective allocation of those charges, based on negative deviations (from updated load and VER forecasts) corrected in each intraday commitment process. This approach requires active bidding of load serving entities and VER producers in intraday commitment processes.

[36] Note eligible costs are assigned to a particular settlement, so a generator will not receive uplift credits for the same concept in two different settlements (i.e., the same cost cannot be compensated twice).

- The second possibility (uplift netting), perhaps more realistic for implementation in current ISO markets, allows netting intraday and real-time costs and revenues, while maintaining separate uplift credits for the day-ahead market. This is similar to CAISO's implementation of the FMM, which is considered part of the real-time settlement. To maintain cost reflectivity, uplift charges can be allocated proportionally to the uplift charges resulting from the previous option. This approach reflects current practices in ISO markets –where intraday commitment costs are assigned to real-time uplift credits–, while still improving uplift allocation.

Both uplift computation options are compared in the case study in section 6.4.

6.3.3 Virtual transactions

An extension to the multi-settlement system would allow for, but not necessarily imply, the addition of intraday virtual transactions. Currently, virtual (aka convergence) bids can be placed by financial arbitrageurs in the day-ahead market to buy or sell energy, which must then be sold or bought back in the real-time market. In the day-ahead market, virtual bids are cleared just as any other bid (e.g. a virtual generator can displace an actual generator). However, since virtual bids do not entail any physical power production or consumption, they are removed from the scheduling program in the first commitment process after the day-ahead market, so the physical operation of the power system only accounts for actual generation and load.

The straightforward implementation of the multi-settlement system is to allow virtual bidding in each intraday settlement, but ISOs may prefer (for reliability purposes) to remove virtual bids immediately after the day-ahead market. This approach is also compatible with the multi-settlement system, although it requires defining in which settlement (real-time, or some of the additional intraday settlements) virtual bidders must buy/sell back their day-ahead awards. For example, after implementing the FMM, CAISO decided to settle convergence bids in the FMM instead of the real-time market. Using intraday prices to settle virtual bids can have positive effects; for instance, a usual problem with virtual bids is the inconsistency derived from using hourly intervals in the day-ahead market vs five-minute intervals in the real-time (Parsons et al. 2015). The FMM in CAISO uses fifteen-minute intervals, alleviating this problem, and a hypothetical intraday settlement with hourly intervals would completely solve this inefficiency.

6.4 Illustrative case study

6.4.1 Simulation model

To illustrate the different incentives produced by the two-settlement and the multi-settlement systems, we apply a simulation model to a stylized case example. The simulation consists of a UC&D model with detailed generation constraints (start-up and shut-down trajectories, ramping limits, minimum up/down time, operating reserves, etc., see formulation included in Annex 6.A). The UC&D model represents successively the scheduling sequence from the day-ahead market, through the following intraday settlements, to the real-time. Next, a pricing and settlement tool computes charges and credits for each unit using both the multi-settlement and the two-settlement system.

Figure 34 summarizes the tasks performed by the model. The day-ahead market (UC&D model) receives as inputs generation offers (assuming perfect competition), and day-ahead forecasts for VER and load; and outputs day-ahead prices and schedules. The UC&D model is then re-run for each intraday commitment process, which receives as inputs the commitment status of thermal units (only if it cannot be changed at the time the process takes place, based on each generator's start-up and notification time), and updated VER and load forecasts. Each intraday run outputs intraday prices and schedules used only for the multi-settlement system, and commitment instructions used in both settlement systems. The final module computes an individual settlement for each generating unit as described in section 6.3.2, considering all the previous results.

We consider a thermal power system with two large solar PV generators, which are subject to a forecast error in the day-ahead market. Then, we compare the impact of correcting this error at different times, both on overall system costs and on the economic results of each of these two generators to illustrate the incentives produced by these alternative settlement systems.

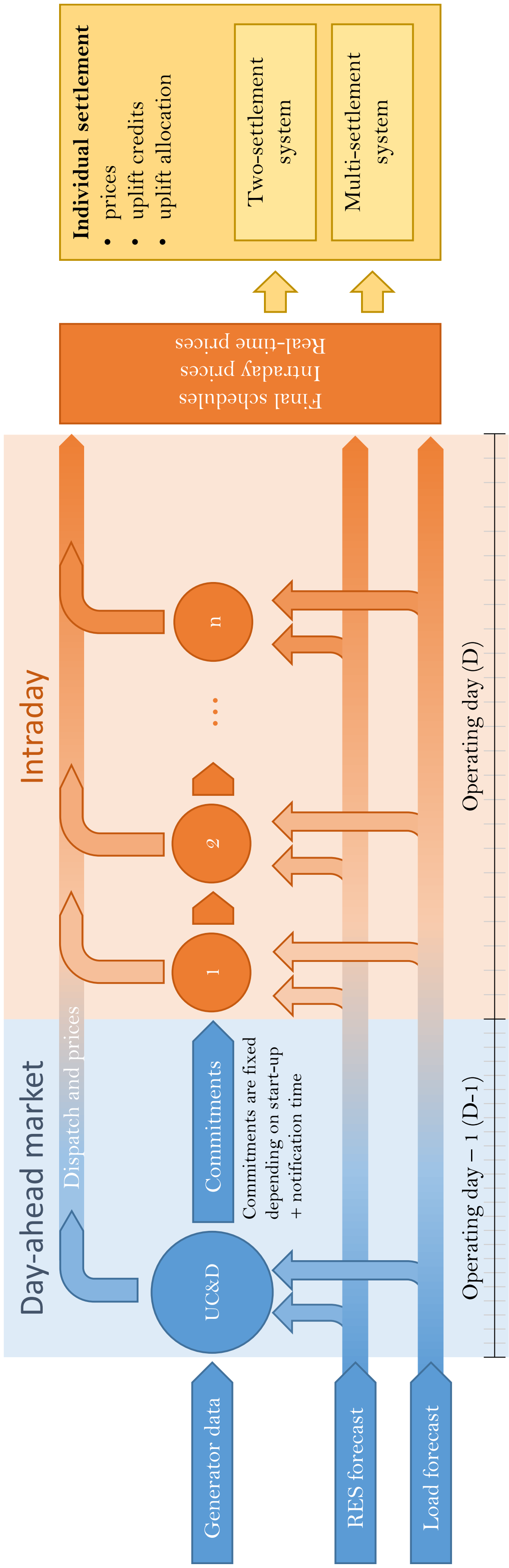
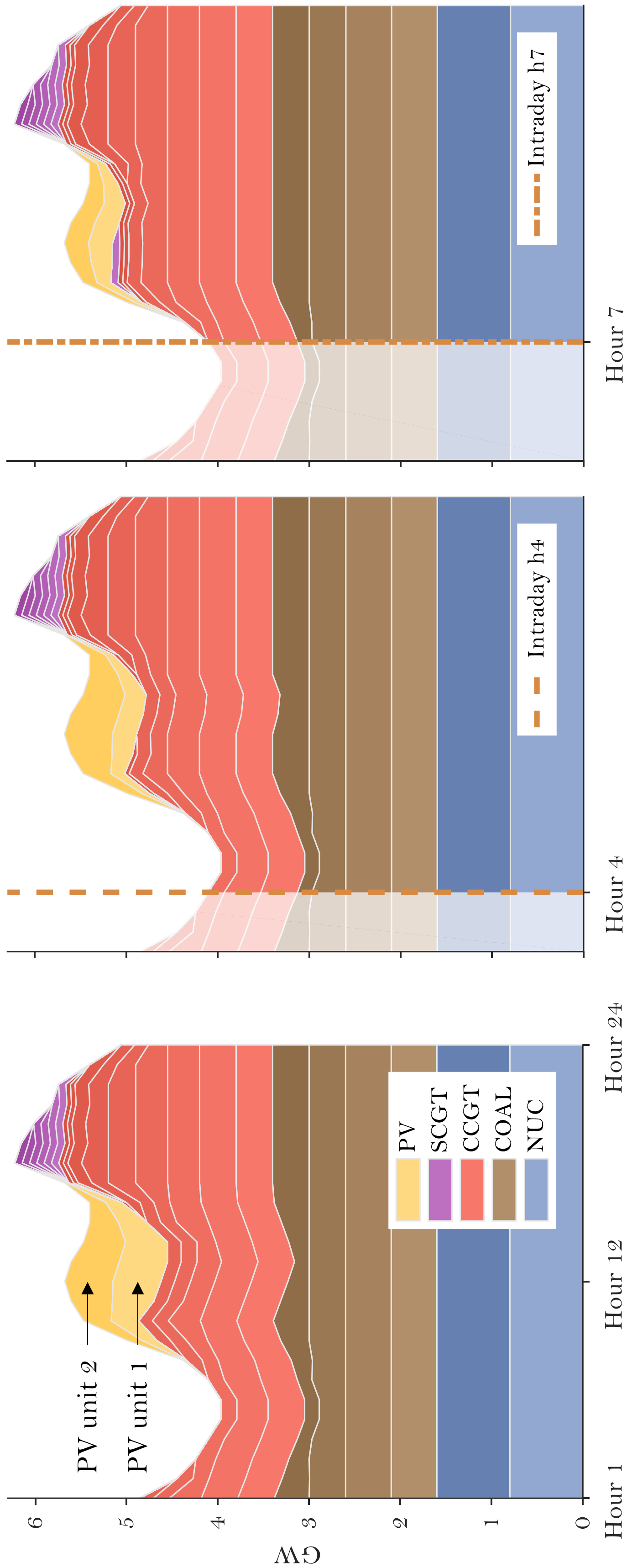


Figure 34. Market sequence simulation overview

6.4.2 Base case results

We consider ICPs with hourly frequency (24 intraday settlements in the operating day, for a total of 26 settlements including the day-ahead and real-time markets), each separately producing financially binding prices for the remaining hourly periods of the operating day. For the sake of simplicity, we assume the only deviations with respect to the day-ahead schedule are those of the PV units, and results are only reported for those settlements that include dispatch changes.

Figure 35 illustrates the scheduling sequence throughout the day. In the day-ahead market –Figure 35(a)–, both solar PV generators (on the top of the plot) provide the same forecast, which basically entails that both expect to produce the same amount and with the same profile starting on hour 8. We then consider only two forecast updates and their corresponding ICPs; the first change takes place in hour 4 (Intraday h4), once PV unit 1 corrects the forecast to 50% of the initial program –The resulting economic dispatch is shown on Figure 35(b)–. PV generator 2 should have made the same correction, but due to a lower ability to update its forecast does not make it until hour 7 (Intraday h7) –see Figure 35(c)–. We assume no further corrections are necessary so this will be the final dispatch, which corresponds to the real-time dispatch.



(a) Day-ahead dispatch

(b) Intraday h4 dispatch

(c) Intraday h7/final dispatch

Figure 35. Dispatch result from each market session in the base case

Each of these corrections has an associated cost due to the redispatch of thermal units; although both corrections are for the same quantities, the latter has a higher cost (36% higher in this case example) because of the greater inflexibility found closer to real time. Dispatch costs are reflected in both market prices and uplift charges, as shown in Figure 36. Uplift charges are reported separately for each settlement system, only day-ahead uplift (allocated to day-ahead load) is identical for all settlement systems. By definition, intraday settlements are not used in the two-settlement system (so no uplift is reported in these cases). The multi-settlement system applies all settlements, but in this case, there are no uplift charges in the real-time market because of the assumption that no corrections are necessary between ICPs and the real-time dispatch. The multi-settlement system with uplift netting produces lower uplift charges than the no-netting option, and in total, requires exactly the same uplift charges as the two-settlement system, only allocated differently.

The first dispatch adjustment (Intraday h4) increases prices slightly during the hours affected by the forecast correction, and due to the abundant ramping capacity available, creates only a small increase in uplift charges. The second correction (Intraday h7) causes greater increases in both market prices and uplift charges.

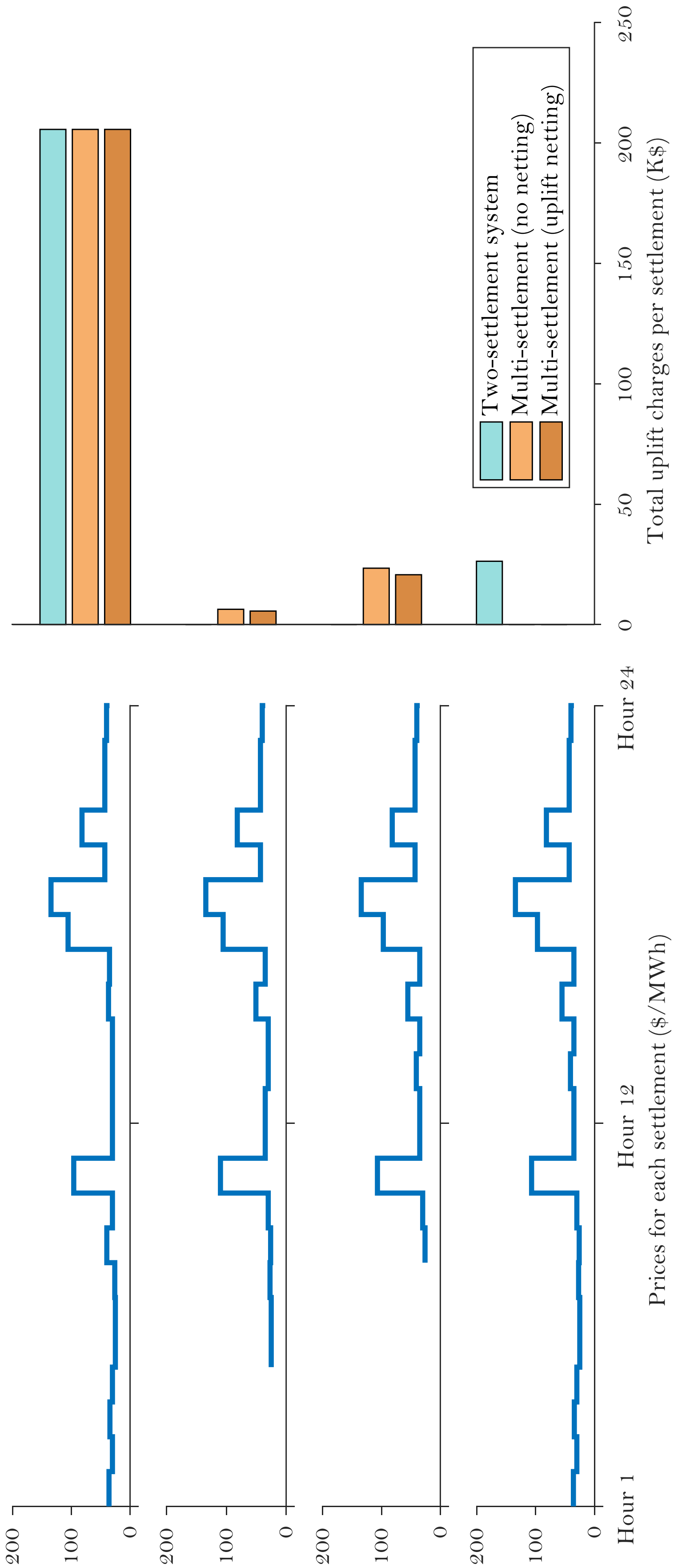


Figure 36. Prices and uplift charges for each of the settlements

The final and most relevant result of the model is the settlement for each unit. Figure 37 shows the net revenue for each of the PV units, detailing the source of the incomes (in this case, only day-ahead market prices) and charges (real-time or intraday charges due to the deviations). Under the two-settlement system, both units obtain the same net revenues, despite the different timing of their deviations. Therefore, it over-penalizes unit 1 and under-penalizes unit 2. In the multi-settlement system, intraday prices and uplift charges reflect the cost of each of the two forecast deviations (in Intraday h4 and h7), which can then be allocated to each of the units accordingly.

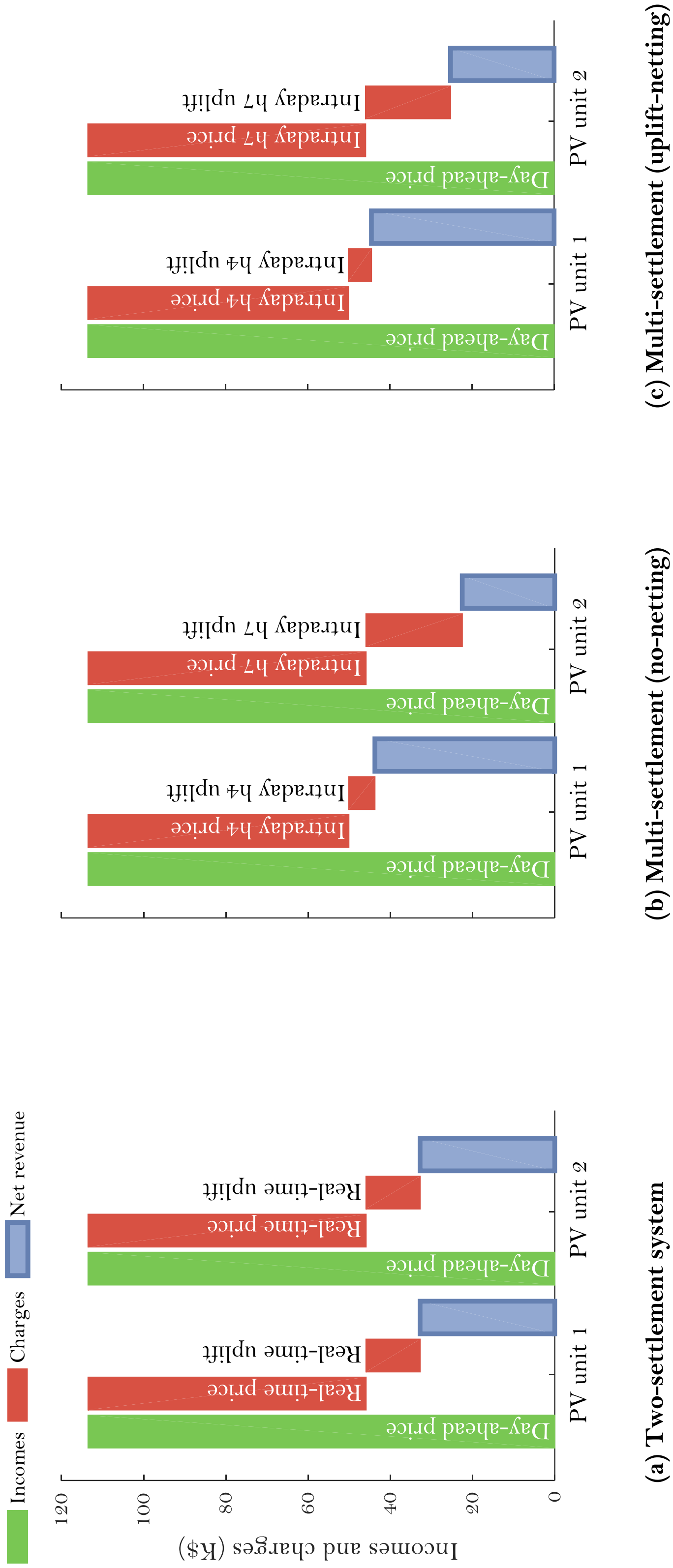
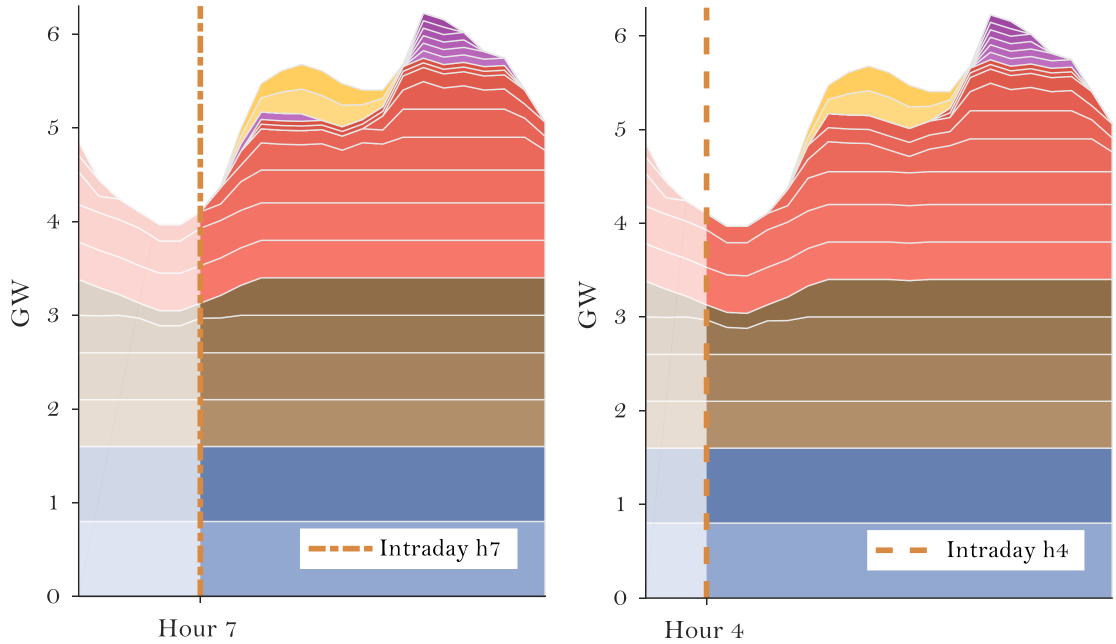


Figure 37. Final settlement for PV units

6.4.3 Sensitivity analysis

The desired effect of the proposed settlement system is to incentivize PV units to submit forecast deviations as soon as possible. To fully assess the incentive produced by intraday settlements vs the two-settlement system, the results of the base case are compared with two additional cases (see Figure 38) in which a) unit 1 corrects its forecast later, and b) unit 2 corrects its forecast sooner.



(a) Both PV units make 'late' forecast correction **(b) Both PV units make 'early' forecast correction**

Figure 38. Dispatch result for the additional cases

Computing the net revenue of each PV unit in these additional cases (shown in Figure 39) provides additional insights on the incentives produced by each of the settlement systems. The scenario where both units make an 'early' forecast correction allows to assess, under each of the settlement systems, the incentive for PV unit 2 (which was 'late' in the base case) to improve its forecasting capabilities and update its forecast sooner.

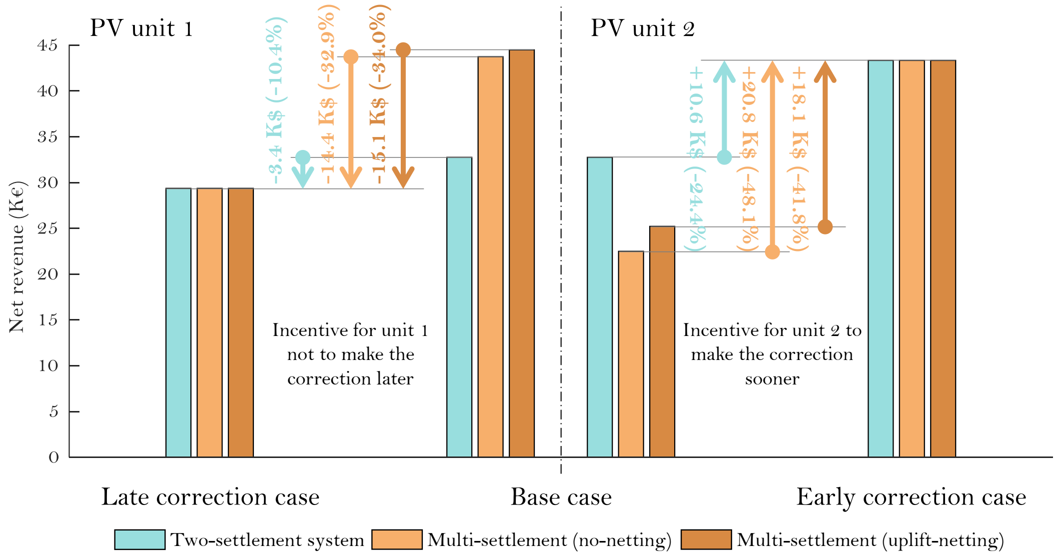


Figure 39. Revenue sensitivity to making forecast corrections later or earlier

The change in revenue from the base case to the early correction case represents the additional profit unit 2 would have made if it had updated its forecast earlier. While all settlement systems reward a forecast improvement, the change in revenue in the multi-settlement system roughly doubles the one in the two-settlement system. And, what is more important, more closely reflects the benefit to the system. Conversely, the scenario where both units make a 'late' forecast correction represents the incentive for PV unit 1 (which was 'early' in the base case) to continue to update its forecast as soon as possible.

6.5 Conclusions

Efficient power system operation requires adapting production schedules as new information (i.e. updated renewable production forecasts) becomes available. In US electricity markets, schedule changes between the day-ahead and real-time market are made at the discretion of the ISO based on its internal expectation of system conditions. This process could be significantly more efficient if this information was provided directly from producers, which can better account for local conditions. Indeed, this locational information has a much more relevant role in US markets –which account for network congestion with detail and rely on locational marginal pricing– than in Europe. Reflecting this clear economic value in price signals not only creates incentives for agents to improve their forecasting accuracy; it also sets a level playing field between renewable and conventional resources, subject to different uncertainties in their day-ahead and intraday scheduling process.

Under the two-settlement system used in ISO markets, this value is not fully disclosed and system costs are not properly allocated. To improve market incentives and cost allocation, each intraday commitment process should be accompanied by its own intraday settlement. This leads to the proposed multi-settlement system, inspired by the positive effect of European intraday markets, but especially conceived for the US context, with a higher degree of centralization. Intraday settlements would allow allocating intraday costs according to cost causality principles, creating efficient signals for market agents to improve forecast accuracy.

Given the clearing and pricing approach in US markets, introducing intraday settlements requires updated uplift computation and allocation rules. Several options are possible, but the most realistic alternative would be to net uplift payments across all intraday and real-time settlements. This option would produce no additional uplift, but because charges from different settlements are lumped into one, it may not be fully cost reflective. Of course, to the extent that uplift payments are minimized by an adequate pricing rule, such inefficiency may become irrelevant. Other important conclusion for the US context is that pricing rules should be consistent across the whole market sequence; otherwise, price differences between day-ahead and intraday markets would arise. These price differences would not reflect changes in operating costs during the intraday, but an inadequate market design, so they would lead to inefficient arbitrage opportunities.

This chapter also draws some conclusions for the European context. If day-ahead markets in Europe turned towards optimal-dispatch-based clearing, and therefore required uplift payments, what would be the most adequate pricing rule for intraday markets? Although one of the conclusions for the US context is that the same pricing rule should be implemented in all market settlements, this conclusion may not apply to European markets. The market sequence in Europe differs from the US in that, even with intraday markets, system operators perform dispatch corrections after the day-ahead market, and in between intraday auctions (see Figure 32). Therefore, price differences between markets, derived from differences in pricing rules, could be irrelevant compared to larger price differences due to system operator actions.

References

ACER-CEER, 2015. Joint ACER-CEER response to the European Commission's Consultation on a new Energy Market Design. October 07, 2015.

Batlle, C., Pérez-Arriaga, I.J., Zambrano-Barragán, P., 2012. Regulatory design for RES-E support mechanisms: Learning curves, market structure, and burden-sharing. Energy Policy 41, 212–220. doi:10.1016/j.enpol.2011.10.039

Borggrefe, F., Neuhoff, K., 2011. Balancing and Intraday Market Design: Options for Wind Integration (SSRN Scholarly Paper No. ID 1945724). Social Science Research Network, Rochester, NY.

CAISO, 2013. FERC Order No. 764 Final Draft Tariff Language. Published November 20, 2013. Accessed February 2016. Available at: www.caiso.com.

CAISO, 2015a. Business Practice Manual for Market Operations, version 43. February 19, 2015.

CAISO, 2015b. CAISO Fifth Replacement Tariff. Version of June 12, 2015.

CAISO, 2016. Order accepting tariff revisions. Docket No. ER16-2445-000, 157 FERC ¶ 61,138. November 21, 2016.

EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, TGE, 2016. EUPHEMIA Public Description, PCR Market Coupling Algorithm. Version 1.5, December 2016.

ERCOT, 2015. ERCOT Nodal Protocols. Version of December 31, 2015.

Eurelectric, 2010. Integrating intermittent renewables sources into the EU electricity system by 2020: Challenges and solutions. May 2010. Available at: www.eurelectric.org

European Commission, 2015a. Commission Regulation (EU) 2015/1222. Establishing a guideline on capacity allocation and congestion management. Official Journal of the European Union, L 197/24. July 24, 2015.

European Commission, 2015b. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions launching the public consultation process on a new energy market design. COM(2015) 340 final, SWD(2015) 142 final. July 15, 2015.

FERC, 2012. Integration of Variable Energy Resources. 18 CFR Part 35, Order No. 764, Docket No. RM10-11-000, June 22, 2012.

FERC, 2014a. Operator-Initiated Commitments in RTO and ISO markets, Staff Analysis, Docket No. AD14-14-000, December 2014

FERC, 2016. Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Notice of Proposed Rulemaking. Docket No. RM17-3-000, 157 FERC ¶ 61,213. December 15, 2016.

GE Energy Consulting, 2014. PJM Renewable Integration Study. Tasks 3B & 4. Market Analysis and Mitigation. March 31, 2014. Available at: www.pjm.com

Helman, U., Hobbs, B.F., O'Neill, R.P., 2008. Chapter 5 - The Design of US Wholesale Energy and Ancillary Service Auction Markets: Theory and Practice, in: Sioshansi, F.P. (Ed.), Competitive Electricity Markets, Elsevier Global Energy Policy and Economics Series. Elsevier, Oxford, pp. 179–243.

Herrero, I., Rodilla, P., Batlle, C., 2018. Enhancing Intraday Price Signals in U.S. ISO Markets for a Better Integration of Variable Energy Resources. Energy Journal 39, No 3. doi:10.5547/01956574.39.3.iher

IEA, 2016. Re-powering markets: Market design and regulation during the transition to low-carbon power systems. Available at: www.iea.org

ISO-NE, 2014. Overview of New England's Wholesale Electricity Markets and Market Oversight. May 6, 2014. Available at: www.iso-ne.com

ISO-NE, 2015. ISO-NE Transmission, Markets and Services Tariff, Section III - Market Rule 1. Version of November 2015.

ISO-NE, NE Power Pool, 2014. Order accepting tariff revisions. Docket No. ER13-1877-001, 147 FERC ¶ 61,073. April 29, 2014.

Klessmann, C., Nabe, C., Burges, K., 2008. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. Energy Policy 36, 3646–3661. doi:10.1016/j.enpol.2008.06.022

Mc Garrigle, E.V., Leahy, P.G., 2015. Quantifying the value of improved wind energy forecasts in a pool-based electricity market. Renewable Energy 80, 517–524. doi:10.1016/j.renene.2015.02.023

MISO, 2015a. MISO Tariff Module C – Energy and Operating Reserve Market. Version of May 2015.

MISO, 2015b. Business Practices Manual No. 002 – Energy and Operating Reserve Markets, revision 14. March 2015.

MISO, 2015c. Market Settlements Calculation Guide. MS-OP-029-r26. Effective October 1, 2015.

Monitoring Analytics, LLC, 2016. Energy Uplift (Operating Reserves) Recommendations. State of the Market Report for PJM, pp 173–214. November 10, 2016.

Neuhoff, K., Batlle, C., Brunekreeft, G., Vasilakos Konstantinidis, C., Nabe, C., Oggioni, G., Rodilla, P., Schwenen, S., Siewierski, T., Strbac, G., 2015. Flexible short-term power trading: Gathering experience in EU countries. Discussion Papers, Deutsches Institut für Wirtschaftsforschung.

NYISO, 2013. Day-Ahead Scheduling Manual. February 2013.

NYISO, 2014. NYISO Accounting and Billing Manual. Version 3.3. Effective December 29, 2014.

NYISO, 2015. Market Administration and Control Area Services Tariff (MST). Version of May 2015.

Parsons, J.E., Colbert, C., Larrieu, J., Martin, T., Mastrangelo, E., 2015. Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets. MIT Cent. Energy Environ. Policy Res. No. 15-002 doi:10.2139/ssrn.2574397

PJM, 2013a. Commitment Decision Making (presentation). August 20, 2013. Available at www.pjm.com

PJM, 2013b. Intermediate Term Security Constrained Economic Dispatch (IT SCED) Engine Overview. November 2013. Available at www.pjm.com

PJM, 2015a. PJM Manual 11: Energy & Ancillary Services Market Operations, revision 72. Effective January 16, 2015.

PJM, 2015b. PJM Manual 28: Operating Agreement Accounting, revision 71. Effective June 1, 2015.

PJM, 2016. PJM Interconnection, L.L.C. Report on Price Formation Issues. Docket No. AD14-14-000. February 17, 2016.

PJM, 2017. Order on proposed tariff revisions. Docket No. ER16-372-002, 158 FERC ¶ 61,133. February 3, 2017.

Annex 6.A Model formulation

6.A.1 Indexes and sets

$g \in G$	Thermal generating units
$r \in R$	Renewable generating units
$t \in T$	Hourly periods
$g \in G^{MR}$	Subset of generating units under must-run constraints

6.A.2 Parameters

D_t	Load in hour t [MW]
S_t	Spinning-reserve requirement in hour t [MW]
C_g^{LV}	Linear variable cost of unit g [$/MWh]
C_g^{NL}	No-load cost of unit g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of unit g [$]
C_g^{SU}	Start-up cost of unit g [$]
$\bar{P}_g$	Maximum power output of unit g [MW]
$\underline{P}_g$	Minimum power output of unit g [MW]
RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
TD_g	Minimum downtime of unit g [h]
TU_g	Minimum uptime of unit g [h]
SD_g	Shut-down capability of unit g [MW]
SU_g	Start-up capability of unit g [MW]
$PF_{r,t}$	Production forecast of unit r at hour t [MW]

6.A.3 Variables

6.A.3.1 Positive variables:

nse_t	Non-served energy in hour t [MWh]
$p_{g,t}$	Power output at hour t of unit g above its minimum output $\underline{P}_g$ [MW]
$s_{g,t}$	Spinning reserve provided by unit g at hour t [MW]
pf_t^{spill}	Renewable production spill in hour t [MWh]

6.A.3.2 Binary variables:

$u_{g,t}$	Commitment status of unit g at hour t, 1 if the unit is online and 0 if offline
$v_{g,t}$	Start-up status of unit g, 1 if the unit starts-up at hour t
$w_{g,t}$	Shut-down status of unit g, 1 if the unit shuts-down at hour t

6.A.4 Formulation

$$\min \sum_{t\in T}\left[\sum_{g\in G}\left[C_g^{NL}u_{g,t}+C_g^{LV}\left(\underline{P}_g u_{g,t}+p_{g,t}\right)+C_g^{SU}v_{g,t}+C_g^{SD}w_{g,t}\right]+C^{NSE}nse_t\right] \tag{6.1}$$

$$s.t.\quad \sum_{g\in G}\left[\underline{P}_g u_{g,t}+p_{g,t}\right]+\sum_{r\in R}PF_{r,t}-pf_t^{spill}=D_t-nse_t \qquad \forall t \tag{6.2}$$

$$\sum_g s_{g,t}\geq S_t \qquad \forall t \tag{6.3}$$

$$u_{g,t}-u_{g,t-1}=v_{g,t}-w_{g,t} \qquad \forall g\notin G^{MR},t \tag{6.4}$$

$$\sum_{i=t-TU_g+1}^{t} v_{g,i}\leq u_{g,t} \qquad \forall g\notin G^{MR},t\in[TU_g,T] \tag{6.5}$$

$$\sum_{i=t-TD_g+1}^{t} w_{g,i}\leq 1-u_{g,t} \qquad \forall g\notin G^{MR},t\in[TD_g,T] \tag{6.6}$$

$$p_{g,t}+s_{g,t}\leq\left(\overline{P}_g-\underline{P}_g\right)u_{g,t}-\left(\overline{P}_g-SU_g\right)v_{g,t} \qquad \forall g,t \tag{6.7}$$

$$p_{g,t}+s_{g,t}\leq\left(\overline{P}_g-\underline{P}_g\right)u_{g,t}-\left(\overline{P}_g-SD_g\right)w_{g,t} \qquad \forall g,t \tag{6.8}$$

$$p_{g,t}+s_{g,t}-p_{g,t-1}\leq RU_g \qquad \forall g,t \tag{6.9}$$

$$p_{g,t-1}-p_{g,t}\leq RD_g \qquad \forall g,t \tag{6.10}$$

$$u_{g,t}=1,\quad v_{g,t},w_{g,t}=0 \qquad \forall g\in G^{MR},t \tag{6.11}$$

$$pf_t^{spill}\leq\sum_{r\in R}PF_{r,t} \qquad \forall t \tag{6.12}$$

6.A.5 Pricing model

In line with recommendations in FERC (2016) prices are computed in a second run of the previous model, in which commitment variables are fixed to their optimal values for uncommitted units (fixed to zero), and non-fast-start units (fixed to one). For fast-start units that were committed, however, commitment variables are not fixed, and they are relaxed (binary variables become continuous). Fast-start units are defined as those with a start-up time (TS_g) of one hour or less, and a minimum uptime (TU_g) of one hour or less.

Annex 6.B Case example data

Table xviii shows the data for the thermal generating units considered. The meaning of each parameter is defined in Annex 6.A, except for TS_g which stands for start-up and notification time, and is used as described in section 6.4.1. Units NUC1 and NUC2 are defined as must-run units and, therefore, the definition of some parameters is unnecessary for these units. C^{NSE} was set to 10,000 $/MWh.

Table xviii. Generating units data

Units	$\overline{P}_g$	$\underline{P}_g$	TU_g	TD_g	TS_g	RU_g	RD_g	SU_g	SD_g	C_g^{NL}	C_g^{LV}	C_g^{SU}	C_g^{SD}
	[MW]			**[h]**		**[MW/h]**		**[MW]**		**[$/h]**	**[$/MWh]**	**[k$]**	
NUC1	800	700	-	-	-	50	50	-	-	0	7	-	-
NUC2	800	700	-	-	-	40	40	-	-	0	9	-	-
COAL1	500	200	8	5	6	100	80	200	400	1500	20	90	0
COAL2	500	200	8	5	6	100	80	200	400	1500	23	90	0
COAL3	400	160	7	5	5	80	80	160	160	1200	26	70	0
COAL4	400	160	7	5	5	80	80	160	160	1200	30	70	0
CCGT1	400	200	4	2	4	200	200	400	500	2000	20	12	0
CCGT2	400	200	4	2	4	200	200	400	500	2000	25	12	0
CCGT3	350	175	4	2	4	200	200	300	300	2000	30	12	0
CCGT4	350	175	4	2	4	200	200	300	300	2000	35	12	0
CCGT5	300	150	2	2	3	200	200	250	250	1500	40	10	0
CCGT6	300	150	2	2	3	200	200	250	250	1500	43	10	0
CCGT7	300	150	2	2	3	200	200	250	250	1500	45	10	0
CCGT8	100	50	2	1	3	200	200	80	80	600	48	4	0
CCGT9	100	50	2	1	3	200	200	80	80	600	50	4	0
SCGT1	100	80	2	1	1	50	50	100	100	2000	60	5	0
SCGT2	100	80	2	1	1	50	50	100	100	2000	65	5	0
SCGT3	100	80	1	1	0	50	50	100	100	2000	70	5	0
SCGT4	80	80	1	1	0	50	50	80	80	1500	75	5	0
SCGT5	80	80	1	1	0	50	50	80	80	1500	80	5	0
SCGT6	80	80	1	1	0	50	50	80	80	1500	85	5	0

Table xix contains hourly demand and spinning reserve requirements, and the day-ahead forecast used for both PV units in the case example.

Table xix: Time dependent data

Period	$PF_{r,t}$	D_t [MW]	S_t
H01	0.0	4856.40	242.82
H02	0.0	4446.00	222.30
H03	0.0	4240.80	212.04
H04	0.0	4104.00	205.20
H05	0.0	3967.20	198.36
H06	0.0	3967.20	198.36
H07	0.0	4104.00	205.20
H08	15.5	4377.60	218.88
H09	162.2	4993.20	249.66
H10	302.2	5472.00	273.60
H11	453.1	5608.80	280.44
H12	526.6	5677.20	283.86
H13	528.2	5608.80	280.44
H14	459.5	5472.00	273.60
H15	312.6	5403.60	270.18
H16	175.8	5403.60	270.18
H17	23.1	5677.20	283.86
H18	0.0	6224.40	311.22
H19	0.0	6156.00	307.80
H20	0.0	6019.20	300.96
H21	0.0	5814.00	290.70
H22	0.0	5745.60	287.28
H23	0.0	5403.60	270.18
H24	0.0	5061.60	253.08

Annex 6.C Uplift computation and allocation

This annex presents general uplift computation and allocation rules for a two-settlement system, representative of current rules in ISO markets, although simplified to the scope of this paper. Each step in the computation is then extended to the multi-settlement system.

6.C.1 Market revenue computation

6.C.1.1 Two-settlement system

We define $MR_{g,t,DA/RT}$ as the market revenue obtained by each unit, in each settlement interval, in the day-ahead or real-time market, it includes energy and reserves revenue. The real-time market energy and reserves price is used to settle only differences between day-ahead and real-time schedules.

$$MR_{g,t,DA} = E_{g,t,DA} \cdot \lambda^{E}_{t,DA} + R_{g,t,DA} \cdot \lambda^{R}_{t,DA} \tag{6.13}$$

$$MR_{g,t,RT} = \Delta E_{g,t,DA \to RT} \cdot \lambda^{E}_{t,RT} + \Delta R_{g,t,DA \to RT} \cdot \lambda^{R}_{t,RT} \tag{6.14}$$

6.C.1.2 Multi-settlement system

We define the index $s \in S$ for all the settlements, including the day-ahead (DA) and real-time (RT) settlements, which would correspond to the first and last elements of the index. Extending the two-settlement formulation above, the market revenue for each settlement is:

$$MR_{g,t,s} = \Delta E_{g,t,s-1 \to s} \cdot \lambda^{E}_{t,s} + \Delta R_{g,t,s-1 \to s} \cdot \lambda^{R}_{t,s} \tag{6.15}$$

Note for $s = DA$ (for the day-ahead settlement), $s-1$ does not exist, that is, the amount settled at the day-ahead price is not the difference with a previous settlement, but the complete day-ahead schedule.

A C. 1.1 Eligible variable and no-load cost

6.C.1.3 Two-settlement system

We define $C^{LV}_{g,t,DA/RT}$ and $C^{NL}_{g,t,DA/RT}$ as the variable and no-load cost respectively, of each unit and during each settlement interval, as per the day-ahead or real-time dispatch instructions. Likewise, we compute the eligible variable ($EC^{LV}_{g,t,DA/RT}$) and no-load cost ($EC^{NL}_{g,t,DA/RT}$) separately, for each unit and during each settlement period, for the day-ahead or the real-time settlement.

Day-ahead costs are only eligible for uplift if they are actually incurred in real time (i.e., only if the unit is not dispatched down or de-committed in real-time):

$$EC^{LV}_{g,t,DA} = \text{Min}\left\{C^{LV}_{g,t,DA}; C^{LV}_{g,t,RT}\right\} \tag{6.16}$$

$$EC^{NL}_{g,t,DA} = \text{Min}\left\{C^{NL}_{g,t,DA}; C^{NL}_{g,t,RT}\right\} \tag{6.17}$$

Real-time costs are only eligible for uplift if they have not already been recognized in day-ahead eligible costs:

$$EC^{LV}_{g,t,RT} = C^{LV}_{g,t,RT} - EC^{LV}_{g,t,DA} \tag{6.18}$$

$$EC^{NL}_{g,t,RT} = C^{NL}_{g,t,RT} - EC^{NL}_{g,t,DA} \tag{6.19}$$

In our case study, we assume generators follow real-time dispatch instructions, in practice, uninstructed deviations may make certain costs not eligible for uplift.

6.C.1.4 Multi-settlement system

Extending the two-settlement formulation above, the eligible variable and no-load cost for each settlement is:

$$EC_{g,t,s}^{LV} = \text{Min}\left\{C_{g,t,s}^{LV}; C_{g,t,RT}^{LV}\right\} - \sum_{s'<s} EC_{g,t,s'}^{LV} \tag{6.20}$$

$$EC_{g,t,s}^{NL} = \text{Min}\left\{C_{g,t,s}^{NL}; C_{g,t,RT}^{NL}\right\} - \sum_{s'<s} EC_{g,t,s'}^{NL} \tag{6.21}$$

Where the first term imposes the condition that eligible costs are actually incurred in real-time, and the second term excludes costs that have already been recognized in previous settlements.

6.C.2 Eligible commitment cost

6.C.2.1 Two-settlement system

The formulation for eligible commitment (start-up and shut-down) cost is slightly different because it cannot be attributed to a single settlement period. Instead, we define for each generator a commitment period (cp) as a set of adjacent settlement intervals in which a unit is committed, and an eligible commitment cost for each commitment period ($EC_{g,cp,s}^{C}$). There will be a commitment period for each start-up instruction.

The criterion to follow is analogous to the one presented for variable and no-load costs. Day-ahead commitment periods are only eligible if they intersect a real-time commitment period (i.e., if the unit actually starts). Real-time commitment periods are only eligible for uplift if they do not intersect an eligible day-ahead commitment period (i.e., they have not already been recognized as eligible day-ahead costs).

6.C.2.2 Multi-settlement system

This criterion can be extended to multiple settlements, in this case, a commitment period is eligible if it intersects a real-time commitment period and it does not intersect any eligible commitment period from a previous settlement. For simplicity, this process is illustrated in Figure 40.

Lastly, commitment costs can be uniformly distributed across a commitment period for the purpose of uplift allocation. Therefore, the eligible commitment cost for each unit, interval and settlement, is the average commitment cost over all dispatch intervals of an eligible commitment period:

$$EC^{C}_{g,t,s} = \frac{\sum_{t\in cp} C^{SU}_{g,t,s} + C^{SD}_{g,t,s}}{\sum_{t\in cp} 1} \qquad : cp \text{ is eligible} \tag{6.22}$$

As shown in section 6.C.2.3, this rule can lead to eligible costs above actual costs, in that case eligible costs are proportionally reduced to match actual costs.

6.C.2.3 Illustration (Multi-settlement system)

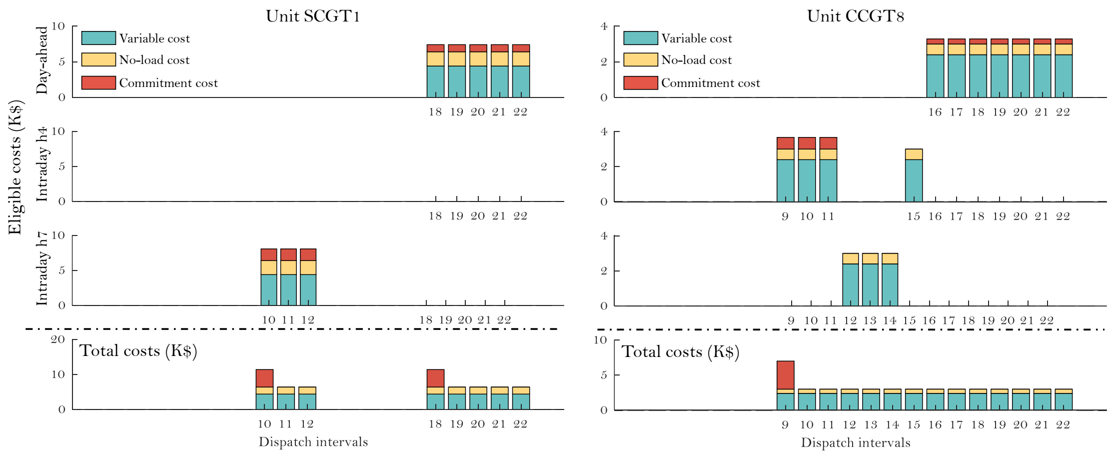


Figure 40. Sample eligible cost computation

Figure 40 shows, in the bottom plots, the final operating cost of two units (SCGT1 and CCGT8) in the base case. The three plots above show the portion of those costs assigned (defined as eligible) to the day-ahead, intraday h4 and intraday h7 settlements respectively. The real-time settlement is omitted because we assumed no dispatch changes between the intraday commitment and the real-time dispatch. The first case (SCGT1) is quite simple; the unit has two commitment periods (10-12 and 18-22) during which it operates at a constant output. Both commitment periods are eligible according to the intersection rule. The first commitment is instructed in the intraday h7 process, so all of its cost is assigned to the intraday h7 settlement. The second commitment was already necessary in the day-ahead schedule, so its cost is assigned to the day-ahead settlement. Note start-up costs are uniformly distributed along all the hours in the commitment period.

The second case (CCGT8) shows a more complex possibility. The unit has a single commitment period in real-time (9-22), but at the time of the intraday h4 process it had two separate start-up instructions. Following the intersection rule, the commitment period 9-11 in intraday h4 would be eligible, since it intersects the real-time commitment period and it does not intersect any previous commitment period. However, that would lead to eligible costs above actual costs. In this case, actual commitment costs are split between the day-ahead and the intraday h4 settlement.

6.C.3 Uplift computation

6.C.3.1 Two-settlement system

We compute the shortfall for each unit and for each period, separately for the day-ahead and real-time market:

$$SF_{g,t,DA} = EC^{LV}_{g,t,DA} + EC^{NL}_{g,t,DA} + EC^{C}_{g,t,DA} - MR_{g,t,DA} \tag{6.23}$$

$$SF_{g,t,RT} = EC^{LV}_{g,t,RT} + EC^{NL}_{g,t,RT} + EC^{C}_{g,t,RT} - MR_{g,t,RT} \tag{6.24}$$

Units with a positive shortfall over the course of the trading day, calculated separately for each settlement, are awarded uplift payments ($UP_{g,s}$).

$$UP_{g,DA} = \max\left(0; \sum_{t \in day} SF_{g,t,DA}\right) \tag{6.25}$$

$$UP_{g,RT} = \max\left(0; \sum_{t \in day} SF_{g,t,RT}\right) \tag{6.26}$$

6.C.3.2 Multi-settlement system (no-netting)

The extension to the multi-settlement system is straightforward:

$$SF^{no-net}_{g,t,s} = EC^{LV}_{g,t,s} + EC^{NL}_{g,t,s} + EC^{C}_{g,t,s} - MR_{g,t,s} \tag{6.27}$$

$$UP^{no-net}_{g,s} = \max\left(0; \sum_{t \in day} SF_{g,t,s}\right) \tag{6.28}$$

6.C.3.3 Multi-settlement system (uplift netting)

In the uplift-netting option, a single shortfall is computed for all settlements except the day-ahead market ($s \in S - DA$).

$$SF^{net}_{g,t} = \sum_{s \in S-DA} EC^{LV}_{g,t,s} + EC^{NL}_{g,t,s} + EC^{C}_{g,t,s} - MR_{g,t,s} \tag{6.29}$$

Note $SF^{net}_{g,t} = SF_{g,t,RT}$, so the uplift assigned to intraday and real-time settlements equals $UP_{g,RT}$. However, for the purpose of uplift allocation, it is possible to disaggregate

$UP_{g,RT}$ into the various settlements proportionally to the uplift allocation in the no-netting option.

$$UP^{net}_{g,s\in S-DA} = UP^{no-net}_{g,s} \frac{UP_{g,RT}}{\sum\limits_{s\in s-DA} UP^{no-net}_{g,s}} \tag{6.30}$$

While the day-ahead uplift remains the same

$$UP^{net}_{g,DA} = UP^{no-net}_{g,DA} \tag{6.31}$$

6.C.4 Uplift allocation

6.C.4.1 Two-settlement system

The uplift charges $UC_{a,t,DA}$ for each agent (a) in each period are proportional to its uplift obligation $UO_{a,t,DA}$, typically, in the day ahead market the uplift obligation for an agent is simply its net load consumption. Assigning uplift obligations in the real-time market can be more complex, for the purposes of this paper it is enough to consider uplift obligations $UO_{a,t,RT}$ as positive demand increases and VER production decreases. We assume all other generation follows dispatch instructions, but in practice, uninstructed deviations could also be assigned uplift obligations.

6.C.4.2 Multi-settlement system

In the multi-settlement system, the uplift obligation remains the same as in the two-settlement system. For the rest of the settlements, uplift obligations $UO_{a,t,s}$ correspond to positive demand increases and VER production decreases, calculated separately for each settlement.

Total uplift payments are assigned to each settlement period proportionally to the total positive shortfall in each period (other criteria are possible), and finally allocated to each agent proportionally to its uplift obligations. The procedure is the same in the two-settlement system so it is not repeated for brevity:

$$UC_{a,t,s} = \frac{\sum\limits_{g} UP_{g,s}}{\sum\limits_{t\in day}\left(\max\left(0; \sum\limits_{g} SF_{g,t,s}\right)\right)} \cdot \max\left(0; \sum\limits_{g} SF_{g,t,s}\right) \cdot \frac{UO_{a,t,s}}{\sum\limits_{a} UO_{a,t,s}} \tag{6.32}$$

There could be instances where this allocation rule does not collect enough charges to pay for all uplift credits. For example, if there are uplift credits assigned to a dispatch interval in which no agent has an uplift obligation. In these rare cases, residual uplift can be allocated proportionally to these uplift charges.

7 Conclusions and future work

This chapter presents the main findings of the document, providing recommendations to improve the design of electricity markets in low-carbon power systems. Previous chapters analyzed several design elements independently –pricing and clearing rules, bidding formats and intraday markets–, so this recapitulation provides a more comprehensive vision of the necessary market reforms. Finally, additional research that could complement the analysis in this work is proposed.

7.1 Summary

The need for market reforms in short-term electricity markets mainly arises from the introduction of VER, and the consequent increased complexity in the operation. Some of the existing market tools are insufficient to handle the increased needs of market agents. For instance, bidding formats in European markets cannot represent some of the increasingly relevant operating constraints of generation units, degrading the operational efficiency of the power system. New energy resources, such as storage and aggregators, require new and adapted bidding formats, both in the US and Europe. The most efficient way to incorporate these constraints in power markets is through resource-specific bidding formats, but to do so in a computationally tractable way, some clearing approaches should be avoided.

Imposing uniform pricing in European power markets has derived in unnecessarily complex clearing algorithms, however, welfare-maximizing clearing algorithms used in US markets, require an ex-post price computation step. Computing prices when complex (non-convex) bids are used has proven to be a challenging problem, especially in a context of large VER penetration. In US markets, efforts to reduce uplift payments should continue, but there is also an increasing need to improve the allocation of uplift charges, in a way that does not hinder demand participation.

The integration of VER introduces uncertainty in day-ahead market programs, that will frequently require corrections. In this regards, intraday price signals are critical to incentivize market agents to provide updated information to market or power system operators. Especially, updated VER production forecasts that can be taken into account when computing dispatch corrections. Improving intraday price signals should be a priority in US markets, where the current market structure would allow the introduction of financially binding prices in intraday commitment processes, without the need to adopt European-like intraday markets.

7.2 Main recommendations and contributions

7.2.1 Tradeoffs between uplift and uniform pricing

The differences between clearing and pricing rules in US and EU markets highlights the complexity of this particular design element. Uniform pricing in European markets requires a complex clearing approach to find an equilibrium between buy and sell orders, while guaranteeing all accepted orders are profitable at the market price. This clearing approach unavoidably leads to a suboptimal market welfare. The clearing approach in US markets maximizes market welfare, but it requires uplift payments for some participants that incur in losses at the market price, distorting marginal price signals. Indeed, the positive properties of marginal pricing do not hold in non-convex markets, leading to these differences in implementation.

This problem clearly calls for trading-off between the desirable properties of alternative clearing and pricing rules, and the objective of uniform pricing should not be pursued (as it is in EU markets) without a clear understanding of its advantages and disadvantages. First, it is difficult to justify any clearing approach that provides a suboptimal market welfare, and the uniform-price-based clearing approach is leading to implementation problems due to its computational complexity. Options based on the optimal-dispatch and an ex-post price computation seem more adequate. Decoupling clearing from pricing also decreases the computational burden, and facilitates the understanding and verification of market results. The ex-post price computation is where more open questions remain, but recent experiences in US markets can provide valuable insights for European markets as well.

US markets initially implemented non-linear pricing rules (marginal cost pricing), but are evolving to alternative schemes aimed at reducing uplift payments; these alternative pricing schemes can be classified as linear pricing rules. The main linear pricing rule applied in practice is based on a relaxed (convex) version of the unit commitment problem (integer relaxation). Different versions of this linear pricing rule are gaining traction in US markets, although regulators are still very careful in their implementation, and have only realized relatively modest benefits. The main improvement over traditional marginal pricing is a reduction of uplift payments, which can lead to improved price signals. However, an improper allocation of the remaining uplift charges (unavoidable in the welfare maximizing clearing approach) can present barriers to the participation of demand resources in the market. Pricing rules should guarantee revenue adequacy for both the supply and demand side of the market.

7.2.2 Impact of VER on pricing rules design

The penetration of VER in power systems is increasing the relevance of the pricing rules discussion. The variability of some renewable sources, such as wind and solar, change the operation regime of thermal generating units. In general, larger shares of renewable resources lead to increased cycling and more frequent start-up/shutdown cycles for thermal units. These changes have a widely different impact on market prices depending on what pricing rule is implemented. While linear and non-linear pricing rules may have resulted in relatively similar prices before, this is no longer the case after renewable generation begins to dominate the operation of power systems.

7.2.3 Long-term effects of pricing rules

One of the main objectives of pricing rule designs should be to provide price signals that drive market agents towards efficient investment decisions. The way in which non-convex costs are reflected in market prices can have a significant impact in the investment signals perceived by market agents, especially in a context of high renewable energy penetration. Linear pricing rules provide incentives closely aligned with the optimal investment decisions, while non-linear pricing rules (that involve higher uplift charges) lead market agents to suboptimal investments.

It is often assumed that linear pricing rules necessarily produce higher energy prices than non-linear pricing rules, but in the long-term, a linear pricing rule can lower energy prices because it promotes investments in a more efficient mix with higher capacity of baseload technologies with lower variable costs technologies.

7.2.4 Need for more complex bidding formats

The penetration of renewable energy resources has significantly altered power systems. In light of these changes, wholesale electricity markets, and in particular day-ahead markets, in their role to guide operating and planning decisions, require increasingly complex bidding formats. While US markets already provide detailed multi-part bids to reflect the most relevant constraints of thermal generators, European markets provide a limited choice of block orders and complex conditions. The energy transition will also bring about the introduction of new energy resources, for example batteries and other types of storage, making it necessary to address their needs and remove barriers for effective competition.

Introducing complex bidding formats is especially challenging in European markets, where the uniform-price-based clearing approach is already causing computational issues. Therefore, an additional benefit of a welfare-maximizing clearing approach is that it would enable more complex bidding formats. In this regard, resource-specific bidding formats, similar to US multi-part bids, can be the most advantageous approach. Resource-specific bidding formats remove inefficiencies by explicitly modeling the most relevant operational constraints, significantly simplifying bidding strategies for market agents. At the same time, this approach removes barriers for small market players (that cannot mitigate bidding format limitations with a large portfolio) and facilitates market monitoring. However, the range of bidding formats offered must be regularly reviewed to ensure new resources have adequate participation models.

7.2.5 Improving price signals in the intraday timeframe

Efficient power system operation requires adapting production schedules as new information (i.e. updated renewable production forecasts) becomes available. In US electricity markets, schedule changes between the day-ahead and real-time market are made at the discretion of the ISO based on its internal expectation of system conditions. This process could be significantly more efficient if this information was provided directly from producers, which can better account for local conditions, although only to the extent that this clear economic value is reflected in the price signals received by agents. Under the two-settlement system used in ISO markets, this value is not fully disclosed and system costs are not properly allocated. To improve market incentives and cost allocation, each intraday commitment process should be accompanied by its own intraday settlement. This leads to the proposed multi-settlement system, inspired by the positive effect of European intraday markets, but especially conceived for the US context, with a higher degree of centralization. Intraday settlements would allow allocating intraday costs according to cost causality principles, creating efficient signals for market agents to improve forecast accuracy.

Given the clearing and pricing approach in US markets, introducing intraday settlements requires updated uplift computation and allocation rules. Several options are possible, but the most realistic alternative would be to net uplift payments across all intraday and real-time settlements. This option would produce no additional uplift, but because charges from different settlements are lumped into one, it may not be fully cost reflective. Of course, to the extent that uplift payments are minimized by an adequate pricing rule, such inefficiency may become irrelevant. Other important conclusion for the US context is that pricing rules should be consistent across the whole market sequence; otherwise, price differences between day-ahead and intraday markets would arise. These price differences would not reflect changes in operating costs during the intraday, but an inadequate market design, so they would lead to inefficient arbitrage opportunities.

7.3 Closing remarks

The goal of this document is to present recommendations that are both realistic and ambitious. These recommendations imply some degree of convergence between US and EU power market designs, and yet, they are compatible with the institutional differences between these two contexts. At the same time, they are ambitious in pushing the "philosophical" barriers between these two designs.

For instance, the European vision from the beginning of the restructuring process was that electricity markets should be as simple as possible to facilitate trading and enhance liquidity. The goal of the market was not to optimize the operation of the system, but rather to balance generation and demand, allowing market agents to self-dispatch and exchange electricity if necessary to adjust their programs. This simplicity enhances the transparency of the market, but said transparency stays away from the actual operation of the power system, which is in the hands of power producers and system operators. The self-dispatching approach was favored by large power producers, which are the ones in a better position to optimize their generation portfolio without any external tools.

The proposals gathered in this document move away from the original vision of European markets, but this does not make them less realistic, as the market itself is moving away from this vision. Complex bidding formats are used more often than ever in all power exchanges, and the determination to clear the market with uniform prices has turned the clearing process into a complex endeavor with all the limitations of the "simple" vision and none of the attempted transparency. European regulators are questioning the benefits of this design and open to improvements[37]. The original vision was that competition between power exchanges (multiple NEMOs can operate in the same region) would provide the incentives for NEMOs to ensure markets meet the requirements of market participants. However, the goal of integrating all Member States into a single electricity market does not allow for diverging market designs across NEMOs. Therefore, this vision should be replaced by greater reliance on participative stakeholder processes that shape the evolution of market design, as it is the case in US markets.

The proposals for the US context are again away from the traditional vision of ISO markets, but realistic and in line with the latest developments. In the last few years, the limitations of marginal cost pricing have been clearly identified in US markets, and the question is now to select the best solution among the multiple pricing alternatives. This document emphasizes the relevance of improving investment incentives through linear pricing rules and highlights the need to create cost-reflective uplift allocation rules. Perhaps, where these proposals break the most with the ISO vision is in allowing greater participation of renewable and demand resources in power markets, however, this ambition is also reflected in recent market design changes. For instance, the motivations for the multi-settlement system proposed here and the fifteen-minute market implemented in CAISO are the same.

7.4 Future work

The analysis in this document recommends some directions for future developments in power markets. However, additional research is necessary for the detailed implementation of some of these measures. In this regard, some of the market design elements that were not discussed in this document should be explored as progress is made in power market developments.

Although this research has focused on the integration of VER, new energy resources will play an increasing role in power systems. Some of the recommendations provided

[37] ACER, 2018. Public consultation on the compliance of the all NEMOs' proposal for the Price Coupling Algorithm and Continuous Trading Matching Algorithm with the CACM Regulation. PC_2018_E_02, April 26, 2018.

examine the adaptation of bidding formats for storage resources, but this research line requires further exploration. Demand response, especially through aggregators, poses new challenges in the design of bidding formats. The business model of aggregators is not well understood, and the full needs of this potentially critical resource, yet unknown.

This research has focused on energy markets (day-ahead and intraday markets) to allow generalizing conclusions to both US and European markets, but developments in reserve and balancing markets also play a critical role in integrating renewable productions. In particular, European markets could benefit from improved coordination between energy and reserve markets. While US markets tend to co-optimize energy and reserves in both day-ahead and real-time markets, European reserve markets are run separately by TSOs.

As indicated in the recommendations, pricing rules should incorporate the computation and allocation of uplift charges in a way that ensures revenue adequacy for demand resources as well. In other words, the distinction between generation and demand is becoming outdated as new resources enter the market, and all market agents should be subject to the same rules. Pricing rules in US markets require further developments in this direction. In the European context, the uniform pricing approach facilitates the equal treatment of all market agents, and further research is necessary to propose alternative pricing schemes that guarantee the same positive properties if uniform pricing is phased out. This line of research will benefit from developments in the US context.

The models proposed in this document for the comparison of pricing rules could be extended to analyze new pricing alternatives. The comparison here focused on general differences between linear and non-linear schemes, but as pricing rules are refined, the proposed methodology can help discern among more specific alternatives. The introduction of intraday settlements in US markets is also relevant for the determination of efficient pricing rules. The incentive effects of intraday price signals and uplift charges should be considered in the design of pricing rules. The modeling approach proposed can be extended as well for the comparison of other pricing approaches.

In the European context, the discussion between continuous markets and intraday auctions is ongoing, and the analysis in this document highlights some of the benefits of an auction-based design (which would have similar properties to the proposed multi-settlement design). Intraday auctions can improve market liquidity with respect to continuous markets, and allow pricing rules consistent with day-ahead markets.

However, this discussion is also affected by the design of reserve markets, and TSO reliability procedures, which were not considered in this analysis. The design of energy markets should be the highest priority, but the discussion of reserve markets should be progressively incorporated, among other reasons, for its implications in intraday markets. This is especially true in the European context, where the coordination between NEMOs and TSOs can be significantly improved, although this issue faces multiple institutional challenges.

Bibliography

ACER-CEER, 2015. Joint ACER-CEER response to the European Commission's Consultation on a new Energy Market Design. October 07, 2015.

ACER, 2018. Public consultation on the compliance of the all NEMOs' proposal for the Price Coupling Algorithm and Continuous Trading Matching Algorithm with the CACM Regulation. PC_2018_E_02, April 26, 2018.

Ammari, S., Cheung, K.W., 2013. Advanced combined-cycle modeling, in: PowerTech (POWERTECH), 2013 IEEE Grenoble. pp. 1–5. doi:10.1109/PTC.2013.6652321

Baldick, R., Helman, U., Hobbs, B.F., O'Neill, R.P., 2005. Design of Efficient Generation Markets. Proceedings of the IEEE 93, 1998–2012. doi:10.1109/JPROC.2005.857484

Balevic, D., Hartman, S., Youmans, R., 2010. Heavy-Duty Gas Turbine Operating and Maintenance Considerations. GER-3620L.1 (10/10), GE Energy, Atlanta, GA.

Batlle, C. & Rodilla, P., 2013. An enhanced screening curves method for considering thermal cycling operation costs in generation expansion planning. IEEE Transactions on Power Systems, vol. 28, no. 4, pp. 3683-3691, Nov. 2013.

Batlle, C., Pérez-Arriaga, I.J., Zambrano-Barragán, P., 2012. Regulatory design for RES-E support mechanisms: Learning curves, market structure, and burden-sharing. Energy Policy 41, 212–220. doi:10.1016/j.enpol.2011.10.039

Black and Veatch, 2012, Cost and performance data for power generation technologies. Prepared for the National Renewable Energy Laboratory, February 2012. Available at bv.com/docs/reports-studies/nrel-cost-report.pdf.

Borggrefe, F., Neuhoff, K., 2011. Balancing and Intraday Market Design: Options for Wind Integration (SSRN Scholarly Paper No. ID 1945724). Social Science Research Network, Rochester, NY.

CAISO, 2013. FERC Order No. 764 Final Draft Tariff Language. Published November 20, 2013. Accessed February 2016. Available at: www.caiso.com.

CAISO, 2015a. Business Practice Manual for Market Operations, version 43. February 19, 2015.

CAISO, 2015b. CAISO Fifth Replacement Tariff. Version of June 12, 2015.

CAISO, 2016. Order accepting tariff revisions. Docket No. ER16-2445-000, 157 FERC ¶ 61,138. November 21, 2016.

Chang, G.W., Chuang, G.S., Lu, T.K., 2008. A simplified combined-cycle unit model for mixed integer linear programming-based unit commitment, in: 2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century. pp. 1–6. doi:10.1109/PES.2008.4596496

David Fuller, J., Çelebi, E., 2017. Alternative models for markets with nonconvexities. Eur. J. Oper. Res. 261, 436–449. doi:10.1016/j.ejor.2017.02.032

Eirgrid, SEMO, APX Power & SONI, 2015. I-SEM trialling of EUPHEMIA: initial phase report. September 2015, available at www.sem-o.com

Ela, E., Wang, C., Moorty, S., Ragsdale, K., O'Sullivan, J., Rothleder, M., Hobbs, B., Ela, B.E., Wang, C., Moorty, S., Ragsdale, K., Sullivan, J.O., 2017. Electricity Markets and Renewables. IEEE Power Energy Mag. 15, 70–82. doi:10.1109/MPE.2017.2730827

ENTSO-E, 2017. 3rd Report on the progress and potential problems with the implementation of Single Day-ahead and Intraday Coupling. August 2017. Available at: www.entsoe.eu

EPEX SPOT, 2018. EPEX SPOT Operational Rules, version 008. Available at www.epexspot.com. January 1, 2018.

EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, TGE, 2016. EUPHEMIA Public Description, PCR Market Coupling Algorithm. Version 1.5, December 2016.

ERCOT, 2011. Verifiable Cost Manual, available at www.ercot.com

ERCOT, 2015. ERCOT Nodal Protocols. Version of December 31, 2015.

Eurelectric, 2010. Integrating intermittent renewables sources into the EU electricity system by 2020: Challenges and solutions. May 2010. Available at: www.eurelectric.org

European Commission, 2015a. Commission Regulation (EU) 2015/1222. Establishing a guideline on capacity allocation and congestion management. Official Journal of the European Union, L 197/24. July 24, 2015.

European Commission, 2015b. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions launching the public consultation process on a new energy market design. COM(2015) 340 final, SWD(2015) 142 final. July 15, 2015.

European Commission, 2016. Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity. November 2016. Available at http://ec.europa.eu/

European Stakeholder Committee of the Price Coupling of Regions, 2015. Euphemia Performance, September 2015.

European Stakeholder Committee of the Price Coupling of Regions, 2016. PCR Stakeholder Forum, January 2016.

European Stakeholder Committee of the Price Coupling of Regions, 2017. PCR Status Update, June 2017.

FERC, 1996. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Order No. 888, FERC Stats. & Regs. 31,036, 24 April.

FERC, 1999. Regional Transmission Organizations. Order No. 2000, 89 FERC 61,285, 20 December.

FERC, 2012. Integration of Variable Energy Resources. 18 CFR Part 35, Order No. 764, Docket No. RM10-11-000, June 22, 2012.

FERC, 2014a. Operator-Initiated Commitments in RTO and ISO markets, Staff Analysis, Docket No. AD14-14-000, December 2014.

FERC, 2014b. Uplift in RTO and ISO markets, Staff Analysis, Docket No. AD14-14-000, August 2014.

FERC, 2014c. Notice of proceeding regarding the Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators. Docket No. AD14-14-000. June 19, 2014.

FERC, 2016. Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Notice of Proposed Rulemaking. Docket No. RM17-3-000, 157 FERC ¶ 61,213. December 15, 2016.

FERC, 2017. Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Withdrawal of Notice of Proposed Rulemaking and Termination of Rulemaking Proceeding. Docket No. RM17-3-000, 161 FERC ¶ 61,293. December 21, 2017.

FERC, 2018. Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. Order No. 841, 162 FERC 61,127. February 15, 2018.

GE Energy Consulting, 2014. PJM Renewable Integration Study. Tasks 3B & 4. Market Analysis and Mitigation. March 31, 2014. Available at: www.pjm.com

Gollmer, R., Nowak, M.P., Römisch,W., Schultz, R., 2000. Unit commitment in power generation – a basic model and some extensions. Ann. Oper. Res. 96, 167–189. doi: 10.1023/A:1018947401538

Gribik, P.R., Hogan, W.W., Pope, S.L., 2007. Market-Clearing Electricity Prices and Energy Uplift. Harvard University.

Harvey, S., 2014. Is the California ISO Becoming an Uplift Market? Pricing, Uplift and Commitment (presentation). FTI Consulting. Available at: www.caiso.com

Helman, U., Hobbs, B.F., O'Neill, R.P., 2008. Chapter 5 - The Design of US Wholesale Energy and Ancillary Service Auction Markets: Theory and Practice, in: Sioshansi, F.P. (Ed.), Competitive Electricity Markets, Elsevier Global Energy Policy and Economics Series. Elsevier, Oxford, pp. 179–243.

Herrero, I., Rodilla, P., Batlle, C., 2014. Impact of day-ahead market pricing rules on generation capacity expansion. In Energy & the Economy, 37th IAEE International Conference, New York, USA, June 15-18, 2014. International Association for Energy Economics.

Herrero, I., Rodilla, P., Batlle, C., 2015. Electricity market-clearing prices and investment incentives: The role of pricing rules. Energy Economics 47, 42–51. doi:10.1016/j.eneco.2014.10.024

Herrero, I., Rodilla, P., Batlle, C., 2016. The Need for Intra-day Settlements in US Electricity Markets. In Energy: Expectations and Uncertainty, 39th IAEE International Conference, Bergen, Norway, Jun 19-22, 2016. International Association for Energy Economics.

Herrero, I., Rodilla, P., Batlle, C., 2018. Enhancing Intraday Price Signals in U.S. ISO Markets for a Better Integration of Variable Energy Resources. Energy Journal 39, No 3. doi:10.5547/01956574.39.3.iher

Hogan, W., 1995. A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy. The Electricity Journal, December 1995, pp. 26-37.

Hogan, W., 2014. Electricity Market Design and Efficient Pricing: Applications for New England and Beyond, June 24, 2014

Hogan, W., Ring, B.J., 2003. On minimum-uplift pricing for electricity markets. Electricity Policy Group.

IEA, 2016. Re-powering markets: Market design and regulation during the transition to low-carbon power systems. Available at: www.iea.org

ISO-NE, 2014. Overview of New England's Wholesale Electricity Markets and Market Oversight. May 6, 2014. Available at: www.iso-ne.com

ISO-NE, 2015. ISO-NE Transmission, Markets and Services Tariff, Section III - Market Rule 1. Version of November 2015.

ISO-NE, NE Power Pool, 2014. Order accepting tariff revisions. Docket No. ER13-1877-001, 147 FERC ¶ 61,073. April 29, 2014.

Klessmann, C., Nabe, C., Burges, K., 2008. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. Energy Policy 36, 3646–3661. doi:10.1016/j.enpol.2008.06.022

Kumar, N., Besuner, P., Lefton, S., Agan, D., Hilleman, D., 2012. Power Plant Cycling Costs. Intertek APTECH. Available at www.nrel.gov. April 2012.

Liberopoulos, G., Andrianesis, P., 2016. Critical Review of Pricing Schemes in Markets with Non-Convex Costs. Oper. Res. doi:10.1287/opre.2015.1451

Madani, M., Van Vyve, M., 2015. Computationally efficient MIP formulation and algorithms for European day-ahead electricity market auctions. European Journal of Operational Research, 242(2), 580–593. doi:10.1016/j.ejor.2014.09.060

Martin, A., Müller, J. C., Pokutta, S., 2014. Strict linear prices in non-convex European day-ahead electricity markets. Optimization Methods and Software, 29(1), 189–221. doi:10.1080/10556788.2013.823544

Mc Garrigle, E.V., Leahy, P.G., 2015. Quantifying the value of improved wind energy forecasts in a pool-based electricity market. Renewable Energy 80, 517–524. doi:10.1016/j.renene.2015.02.023

McNamara, R. R., 2011. Methodology to Update ISO Default Operations and Maintenance Adder Values, September 7, 2011. Available at http://www.caiso.com.

MISO, 2015a. MISO Tariff Module C – Energy and Operating Reserve Market. Version of May 2015.

MISO, 2015b. Business Practices Manual No. 002 – Energy and Operating Reserve Markets, revision 14. March 2015.

MISO, 2015c. Market Settlements Calculation Guide. MS-OP-029-r26. Effective October 1, 2015.

Monitoring Analytics, LLC, 2016. Energy Uplift (Operating Reserves) Recommendations. State of the Market Report for PJM, pp 173–214. November 10, 2016.

Morales-España, G., Latorre, J.M., Ramos, A., 2013. Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem. IEEE Transactions on Power Systems, vol. 28, no. 4, pp. 4897-4908, Nov. 2013.

NEMOs, 2017. All NEMOs' proposal for products that can be taken into account by NEMOs in single day-ahead process in accordance with Article 40 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management. November 13, 2017. Available at: www.europex.org/all-nemos

Neuhoff, K., Batlle, C., Brunekreeft, G., Vasilakos Konstantinidis, C., Nabe, C., Oggioni, G., Rodilla, P., Schwenen, S., Siewierski, T., Strbac, G., 2015. Flexible short-term power trading: Gathering experience in EU countries. Discussion Papers, Deutsches Institut für Wirtschaftsforschung.

Nord Pool, 2017a. Product Specification Nordic, Baltic and German market areas. Available at www.nordpoolgroup.com. July 3, 2017.

Nord Pool, 2017b. Product Specifications GB Market. Available at www.nordpoolgroup.com. August 15, 2017.

NYISO, 2001. New York Independent System operator, INC's Motion for Permission to implement Hybrid Fixed Block Generation Pricing Rule. March 20, 2001.

NYISO, 2013. Day-Ahead Scheduling Manual. February 2013.

NYISO, 2014. NYISO Accounting and Billing Manual. Version 3.3. Effective December 29, 2014.

NYISO, 2015. Market Administration and Control Area Services Tariff (MST). Version of May 2015.

O'Neill, R., Castillo, A., Eldridge, B., Hytowitz, R.B., 2016. Dual Pricing Algorithm in ISO Markets. IEEE Trans. Power Syst. 8950, 1–1. doi:10.1109/TPWRS.2016.2614891

O'Neill, R.P., Dautel, T., Krall, E., 2011. Recent ISO software enhancements and future software and modeling plans. Available at https://www.ferc.gov/industries/electric/indus-act/rto/rto-iso-soft-2011.pdf.

Palmintier, B., Webster, M., 2011. Impact of unit commitment constraints on generation expansion planning with renewables. Power and Energy Society General Meeting, 2011 IEEE, pp. 1–7, 24-29 July 2011.

Parsons, J.E., Colbert, C., Larrieu, J., Martin, T., Mastrangelo, E., 2015. Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets. MIT Cent. Energy Environ. Policy Res. No. 15-002 doi:10.2139/ssrn.2574397

Pérez-Arriaga, I, J., Batlle, C., 2012. Impacts of intermittent renewables on electricity generation system operation. Economics of Energy and Environmental Policy, vol. 1, No. 2.

Pérez-Arriaga, I.J., Gómez, T., Batlle, C., Rodilla, P., Cossent, R., Herrero, I., Usera, I., Matropietro, P., Vinci, S., 2017. Adapting market design to high shares of variable renewable energy. International Renewable Energy Agency, Abu Dhabi. ISBN: 978-92-9260-025-9

Pérez-Arriaga, I.J., Knittel, C., Miller, R., Tabors, R., Bharaktumar, A., Birk, M., Burger, S., Chaves, J.P., Dueñas-Martínez., P., Herrero, I., Huntington, S., Jenkins, J., Luke, M., Rodilla, P., Tapia-Ahumada, K., Vergara, C., Xu, N., 2016. Utility of the Future. An MIT Energy Initiative response to an Industry in transition. ISBN: 978-0-692-80824-5. Available at www.energy.mit.edu/uof

Phillips, D., Jenkin, F.P., Pritchard, J.A.T., Rybicki, K., 1969. A mathematical model for determining generating plant mix. Proceedings of the Third IEEE PSCC, Rome.

PJM, 2012. PJM Manual 15: Cost Development Guidelines, available at www.pjm.com.

PJM, 2013a. Commitment Decision Making (presentation). August 20, 2013. Available at www.pjm.com

PJM, 2013b. Intermediate Term Security Constrained Economic Dispatch (IT SCED) Engine Overview. November 2013. Available at www.pjm.com

PJM, 2015a. PJM Manual 11: Energy & Ancillary Services Market Operations, revision 72. Effective January 16, 2015.

PJM, 2015b. PJM Manual 28: Operating Agreement Accounting, revision 71. Effective June 1, 2015.

PJM, 2016. PJM Interconnection, L.L.C. Report on Price Formation Issues. Docket No. AD14-14-000. February 17, 2016.

PJM, 2017. Order on proposed tariff revisions. Docket No. ER16-372-002, 158 FERC ¶ 61,133. February 3, 2017.

Pope, S.L., 2014. Price formation in ISOs and RTOs, principles and improvements. October 2014. FTI Consulting. Available at www.epsa.org

Potomac Economics, 2017. 2016 State of the Market report for the MISO Electricity Markets. June 2017. Available at: www.potomaceconomics.com

PPA (Power Planning Associates), 2002. Dictamen Técnico sobre Costos de Generación de Plantas Térmicas en Colombia para soportar el expediente 7728. In Spanish. April 2002

Ring, B.J., 1995. Dispatch based pricing in decentralised power systems. Ph.D, Thesis Dissertation. University of Canterbury 1995, p. 213.

Rodilla, P., Cerisola, S., Batlle, C., 2014. Modeling the major overhaul cost of gas-fired plants in the unit commitment problem. IEEE Transactions on Power Systems. vol. 29, no. 3, pp. 1001-1011, May 2014 doi: 10.1109/TPWRS.2013.2293604.

Ruiz, C., Conejo, A.J., Gabriel, S.A., 2012. Pricing non-convexities in an electricity pool. IEEE Trans. Power Syst. 27, 1334–1342. doi:10.1109/TPWRS.2012.2184562

Scarf, H.E., 1994. The allocation of resources in the presence of indivisibilities. The Journal of Economic Perspectives 111–128.

Schiro, D.A.D.A., Zheng, T., Zhao, F., Litvinov, E., 2015. Convex Hull Pricing in Electricity Markets: Formulation, Analysis, and Implementation Challenges. IEEE Trans. Power Syst. PP, 1–8. doi:10.1109/TPWRS.2015.2486380

SEMO, 2013. SEM-13-089: Uplift Parameters Decision Paper 2014. 12 December 2013. Available at: www.sem-o.com

SEMO, 2014. Trading and Settlement Code. v15.0. 16 May 2014. Available at: www.sem-o.com

Sundheim, E., 2001. Long-Term Service Agreements: Weighing the Risks and Rewards. Power Engineering, vol. 105, iss. 8, 08/01/2001. Available at www.power-eng.com.

Troy, N., Flynn, D., Milligan, M., O'Malley, M., 2012. Unit Commitment With Dynamic Cycling Costs. Power Systems, IEEE Transactions on , vol.27, no.4, pp.2196,2205, Nov. 2012 doi: 10.1109/TPWRS.2012.2192141

Usera, I., Rodilla, P., Burger, S., Herrero, I., Batlle, C., 2017. The Regulatory Debate About Energy Storage Systems: State of the Art and Open Issues. IEEE Power Energy Mag. 15, 42–50. doi:10.1109/MPE.2017.2708859

Van Vyve, M., 2011. Linear prices for non-convex electricity markets: models and algorithms. CORE Discussion Paper 2011/50.

Vázquez, C., 2003. Modelos de casación de ofertas en mercados eléctricos. PhD (in Spanish). Institute for Research in Technology. Comillas Pontifical University.

Veiga, A., Rodilla, P., Herrero, I., Batlle, C., 2015. Intermittent RES-E, cycling and spot prices: The role of pricing rules. Electr. Power Syst. Res. 121, 134–144. doi:10.1016/j.epsr.2014.11.030