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ENHANCING INTRADAY PRICE SIGNALS IN US ISO MARKETS FOR A BETTER INTEGRATION OF VARIABLE ENERGY RESOURCES

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Abstract - *Efficient operation of power systems increasingly requires accurate forecasting of variable energy resources (VER) production, and flexible resources to accommodate forecast deviations. Therefore, it is of utmost importance to enhance market price signals in the intraday horizon to provide market agents with the necessary incentives to move in this direction. The US ISO approach to reflect in market prices the costs derived from the re-schedules needed to incorporate updated forecast information, based on a two-settlement system, falls short to provide efficient intraday economic signals to, for example, incentivize VER producers to provide accurate and updated forecast information. This paper advocates for a multi-settlement system, which entails calculating intraday price signals as re-schedules are executed, while keeping the efficient centralized dispatch logic of the ISO model. The virtues of a multi-settlement system are illustrated on the basis of a stylized case example. The multi-settlement system appropriately rewards market agents for the value of their forecasts and thus sends efficient signals to improve forecast accuracy, and as a consequence facilitates the integration of VER.*

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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. But 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 uncertainty is significantly lower during intraday markets, than in the day-ahead market. The multiple intertemporal constraints in power systems make the cost derived from forecast errors quite substantial, especially in systems that cannot rely on hydro-reservoir generation. This requires forecast errors be corrected as soon as possible in order 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, thus 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).

The markets run by the Independent System Operators (ISOs) in the United States follow a different approach, which in our view does not present the same positive characteristics. ISO markets include 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 the deviation was corrected (Helman et al., 2008). A centralized dispatch approach can have significant advantages with respect to the European model, but the two-settlement system lacks the more granular signal provided by intraday prices (IEA, 2016) that would capture the different cost in time of forecast corrections, and would allocate it to the units accountable for such cost. Therefore, the

North American design does not provide market agents with the increasingly necessary incentive to improve their forecasts[1] as it is the case in the European intraday markets.

This paper does propose to modify the current market sequence in force in US ISOs through the implementation of intraday sessions, as it is the case in the EU context. We argue in favor of an alternative settlement system conceived for the US ISO context, producing intraday price signals (that somehow mimic the ones that result from European intraday markets), but compatible and consistent with the current (centralized) organization of ISO markets, in which no intraday bilateral trading is considered. As described in section 3, this is a move from the two-settlement system to a "multi-settlement" system, which entails computing a settlement for each intraday commitment process run by the ISO. In section 4, we use a simulation model to illustrate the benefits derived from the economic signals that arose from the multi-settlement system and compare it against the two-settlement system of the US.

2 BACKGROUND

Among the immensely diverse power market designs, there are many different ways to handle the uncertainty associated with day-ahead schedules. As a way of example, Latin American markets, among the first to be implemented, did not include very detailed market mechanisms beyond the day-ahead marginal cost calculation, due to the large availability of hydro-reservoir resources, i.e. due to the extremely low cost of correcting imbalances. As just introduced, in both the European and North American contexts the market designs to deal with intraday deviations are significantly more sophisticated, and they are currently subject to intense debate.

Maybe the major difference between the approaches implemented at both sides of the Atlantic Ocean lies in the degree of separation between market operation and system operation. The European approach is inclined towards allowing market agents to self-dispatch as close to real-time as considered technically possible, in such a way that each agent is responsible for maintaining a balanced program and is given market tools to do so. In the US, a centralized dispatch model is followed, where each unit is responsible for following dispatch instructions from the ISO. This difference has significant implications on how intraday dispatch corrections are made and, importantly for the purpose of this paper, on how the costs derived from such corrections are allocated.

In order to frame the proposal we develop in the core of this paper, this section reviews, in more detail, the different approaches implemented both in the European and North American electricity markets, with a special focus on how they incorporate updated information after the day-ahead market.

[1] Usually, ISOs take charge of the forecasting of renewable generation but, as reviewed in section 2.2, they are increasingly taking actions to incentivize VER to submit their own forecast.

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 across member states through the so-called Price Coupling of Regions initiative (PCR, 2016), while a common and coordinated design for intraday markets is still, at the time of this writing, under discussion (European Commission, 2015a). At the moment, all EU Power Exchanges allow intraday trading, either based on several successive auctions or on continuous trading mechanisms. 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. The Transmission System Operator (TSO) takes charge of final adjustments at the balancing market, which settles all deviations from previous schedules. This process is summarized in Figure 1.

As illustrated in the figure, a prominent feature of European markets is the separation between system and market operation. Therefore, market processes are mostly independent from system reliability constraints, which are enforced in a subsequent step by the TSO.

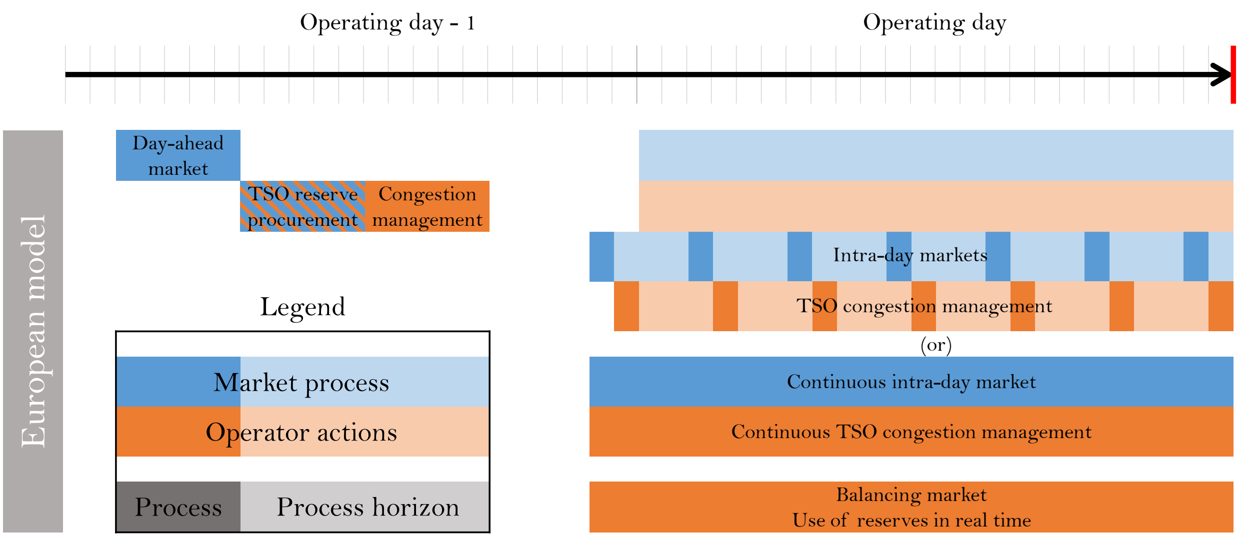


Figure 1: European markets simplified timeline

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 according to 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-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[2]. Take for example the case of Spain, where wind generators have been imbalance responsible since 2004. As illustrated in Figure 2, wind forecast errors have continuously decreased due to forecasting tools enhancements.

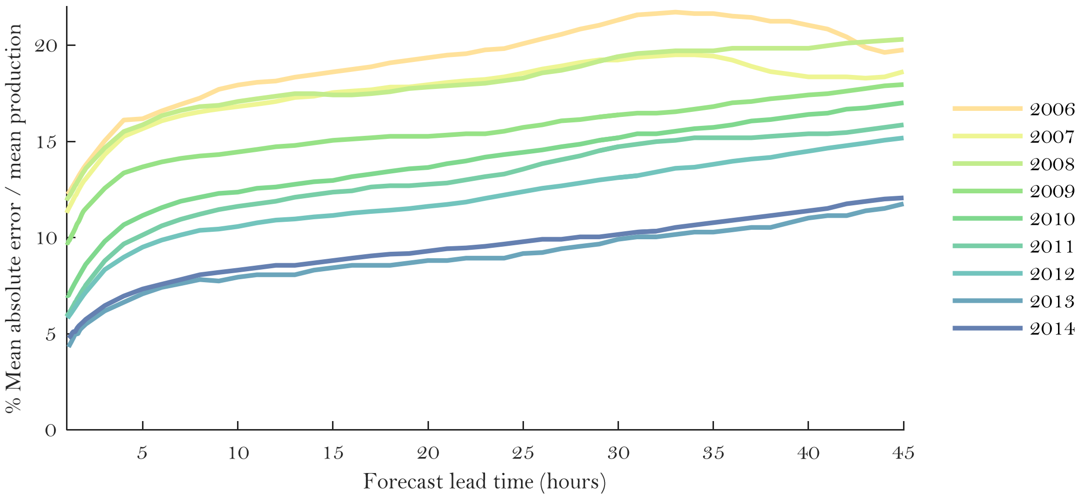


Figure 2: Wind forecast error evolution in Spain (Source: REE)

2.2 The US ISO approach

Spot electricity markets in the US are built around the 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*

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

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 although –while remaining a financial market– it 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 (e.g. minimum and maximum output, ramp constraint) and the transmission system (congestion and losses), the multipart offers submitted by generators (including, among others; offers for the start-up cost, no-load cost and variable cost) and the demand bids.

The real-time market resembles the day-ahead market in the characteristics of the SCED model employed, but the real-time market 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). Real-time market prices capture the marginal cost of generation dispatch when the final system conditions are known, and are used to settle the difference between day-ahead and real-time schedules.

Last-minute dispatch instructions 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 paper as intraday commitment processes[3], 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. Intraday commitment processes are slightly different for each ISO as summarized in Table i. The table includes the denomination of the procedure, with which frequency and look-ahead horizon it is executed, and whether it produces binding commitment or dispatch instructions, and financially binding prices.

[3] In the literature, these processes are frequently called Reliability Unit Commitments (RUC), but RUC is sometimes used to refer only to the first commitment process after the day-ahead market, so to avoid confusion we introduce the more general term "intraday commitment process".

Table i. ISO's intraday timeline summary[4]

ISO	Procedure	Frequency	Look-ahead	Commitment	Dispatch	Prices[5]
CAISO	Residual unit commitment (RUC)	Daily	24-168 h	Long start units		Availability[6]
	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	✓		
	Ancillary Service Optimizer (ASO)	5 min	60 min	✓		
	Intermediate-term SCED	5 min	60-120 min	✓		
	Real-time SCED	5 min	N/A		✓	✓
ERCOT	Day-ahead Reliability Unit Commitment	Daily	Oper. day	✓		
	Hourly RUC	1 h	Oper. day	✓		
	SCED	5 min	N/A		✓	✓

As it is always the case (recall eg. the Latin American example previously mentioned), the reason for the different designs of intraday commitment processes implemented by each ISO can be at least partly explained by the reigning generation mix in each of the systems. For example, CAISO, with significant RES penetration (to US standards), presents probably the most sophisticated design; it uses separate commitment processes for power plants with different start-up times. This is possibly the trend that other ISOs are likely going to follow 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

[4] Sources: FERC 2014 § 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; ERCOT 2015 § 5.2, 6.2

[5] In some ISOs the real-time price is determined ex-post from metered outputs instead of ex-ante from the optimal dispatch. See (Helman et al., 2008).

[6] 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.

> *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."*

The efficiency of these processes depends, primarily, on the accuracy of the information available at the time it is carried out. So far, ISOs have been responsible for obtaining renewable production forecasts used in intraday commitments, but the trend is to increasingly rely on information provided directly by producers[7], which can better account for local conditions. Recently, FERC Order 764 required *"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).

Order 764 is responsible for various changes to ISO markets, for example, CAISO now allows VER producers to provide their own forecast, and has implemented a fifteen minute market (FMM) to dispatch generators using 15-minutes ahead forecast information. Furthermore, the FMM produces financially binding prices, allowing VER owners to buy/sell deviations from the day-ahead market at the FMM price (CAISO, 2013). This incentivizes market agents to submit timely and accurate forecasts to the FMM, in order to minimize imbalance payments at the real-time price.

Order 764 focuses only on intra-hour dispatch corrections, but the problems addressed, and the solutions proposed at the intra-hour level, could be extended to the intraday horizon. A significant problem when making intra-hour/intraday commitments is that the cost incurred can be hardly allocated based on cost-causality, and is generally allocated pro-rata, which clearly does not provide market agents with the increasingly necessary incentive to provide accurate information to the ISO. The philosophy of CAISO's FMM –to compute financially binding prices when 15-minute ahead dispatch corrections are made- could be extended to all intraday commitment processes. Section 3 describes an alternative settlement system built from this perspective that improves cost allocation and incentivizes intermittent generators to provide more accurate forecasts.

3 METHODOLOGY

The first part of this section describes an alternative settlement procedure for ISO markets, which tackles the shortcomings described on section 2.2 while maintaining the fundamental characteristics of the North American designs, e.g. without the need to move towards the intraday bilateral trading implemented in the EU context. The key objective is to enhance the efficiency of the market mechanism through a proper allocation of intraday rescheduling costs, in order to send efficient signals to market agents to do their best to forecast their production programs, a key factor taking into account the increasing penetration of renewables.

[7] A similar motivation –incorporating updated information– supports recent initiatives to make more flexible rules that allow generating units to update their offers in real time, for example, in ISO-NE (ISO-NE & NE Power Pool, 2013) or in PJM (2015c).

Subsection 3.2 describes a simulation model, used to assess the effects of the proposed system in a stylized case example.

3.1 Multi-settlement system

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. 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, to turn the existing two-settlement system into a multi-settlement system.

As reviewed (see Table i), the design of intraday commitment processes requires the definition of multiple parameters; such as the frequency, time horizon, or length of the dispatch interval. The best choices for these parameters will depend on the specifics of each power system and it is not possible to propose a universally valid design. Therefore, this paper does not enter into the question of how frequently or with which characteristics should the ISO perform an intraday commitment, and it simply requires any intraday commitment process to be followed by its own specific settlement. Next section describes the general implementation of intraday settlements focusing on the changes needed for its application on ISO markets.

3.1.1 Price and uplift computation

Price formation in ISO markets is currently an actively discussed issue -see for example (FERC, 2014)-. Multiple methods beyond traditional marginal cost pricing can be found in practice (see Pope, 2014) and in the literature (see Liberopoulos and Andrianesis, 2016) to compute prices in electricity markets with multi-part bids. However, this paper does not impose any particular pricing approach[8] and it just notes that the price computation method used in intraday settlements should be identical to the one used in the real-time market.

Additionally to whichever pricing approach is implemented, ISOs complement generators' market remuneration through uplift credits (aka side-payments or make-whole payments) to compensate operational

[8] We acknowledge this is a significant discussion with potentially relevant effects on market price signals, but it is a topic out of the scope of this paper.

costs not recovered through uniform market 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[9]. Therefore, the uplift computation and allocation rules described next are general, and should be further developed and refined for its implementation in a particular market.

The generalized approach to compute uplifts entails two separate calculations. A make-whole payment is calculated for each generator to compensate shortfalls between day-ahead market revenues and day-ahead market as-bid costs. And a separate make-whole payment reimburses generators for costs incurred either in intraday commitment processes or the real-time market that are not offset by real-time market revenues[10]. Extending this to multiple settlements requires computing separate uplift credits for each intraday settlement. This is described by equation (1): generator g receives an uplift in settlement s for the difference between the additional as–bid cost incurred by the generator with respect to the previous intraday settlement $(s-1)$ and the revenue received in settlement s, but only if this difference is positive.

$$UpliftCredit_{g,s} = \max\left\{0; \left(Cost_{g,s} - Cost_{g,s-1}\right) - Revenue_{g,s}\right\} \qquad \forall g,s \qquad (1)$$

Two important notes should be made; first, even though the uplift is calculated separately for each settlement, it is only calculated ex-post, after the costs eligible for uplift credits are actually incurred. For example, a generator may receive start-up instructions in the day-ahead market, and be therefore eligible for a day-ahead make-whole payment, but if the generator is never actually started (either because it is no longer deemed necessary by the ISO, or because the generator does not follow this dispatch instruction) it will not receive uplift. Second, the cost difference between the day-ahead and real-time (or between two consecutive intraday settlements in the multi-settlement system), is not calculated by a simple subtraction of total costs. Each cost component (start-up, no-load cost) is compared separately and clauses exist so the same costs are not paid for twice.

Once uplift credits are calculated, they can be allocated in various ways. As previously stated, each ISO uses a different procedure. The uplift allocation rule given by equation (2) is based on a general extension of the two-settlement system, in which day-ahead uplift charges are typically paid by day-ahead demand, and real-time uplift charges are allocated proportionally to measured demand and/or to deviations from the

[9] 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.

[10] Again, this general process is adequately adapted by each ISO. For example, CAISO pays for the availability of generators committed in the RUC process through RUC prices, and therefore, computes a separate uplift for the RUC settlement.

day-ahead schedule. An agent a is allocated a portion of the total uplift amount proportionally to its incremental demand with respect to the previous settlement.

$$UpliftCharge_{a,s} = \frac{Demand_{a,s} - Demand_{a,s-1}}{\sum_{a}\left(Demand_{a,s} - Demand_{a,s-1}\right)} \sum_{g} UpliftCredit_{g,s} \qquad \forall a,s \qquad (2)$$

Demand in equation (2) does not only represent energy purchased to serve load; demand in an intraday settlement can be from a generator "buying-back" an expected deviation. These deviations would most typically be procured by non-dispatchable generation due to forecast changes, but could also come from dispatchable generators not able to deliver their full output due to a contingency.

3.2 Simulation model

In order to illustrate the potential of the proposed scheme, we apply 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 the annex) to simulate the market sequence from the day-ahead market through the following intraday settlements until the real-time; and a pricing and settlement tool to compute the charges and credits for each unit using both the multi-settlement and the two-settlement system.

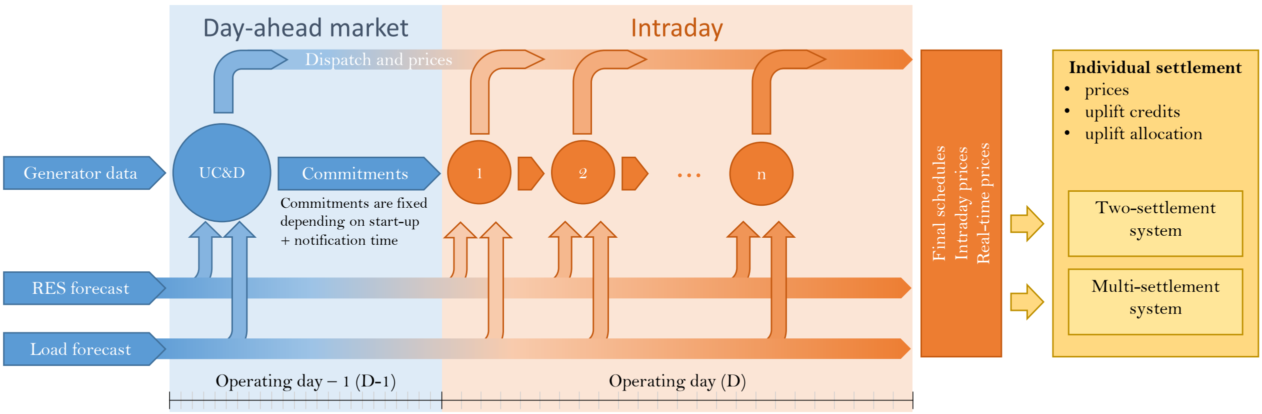


Figure 3: Market sequence simulation overview

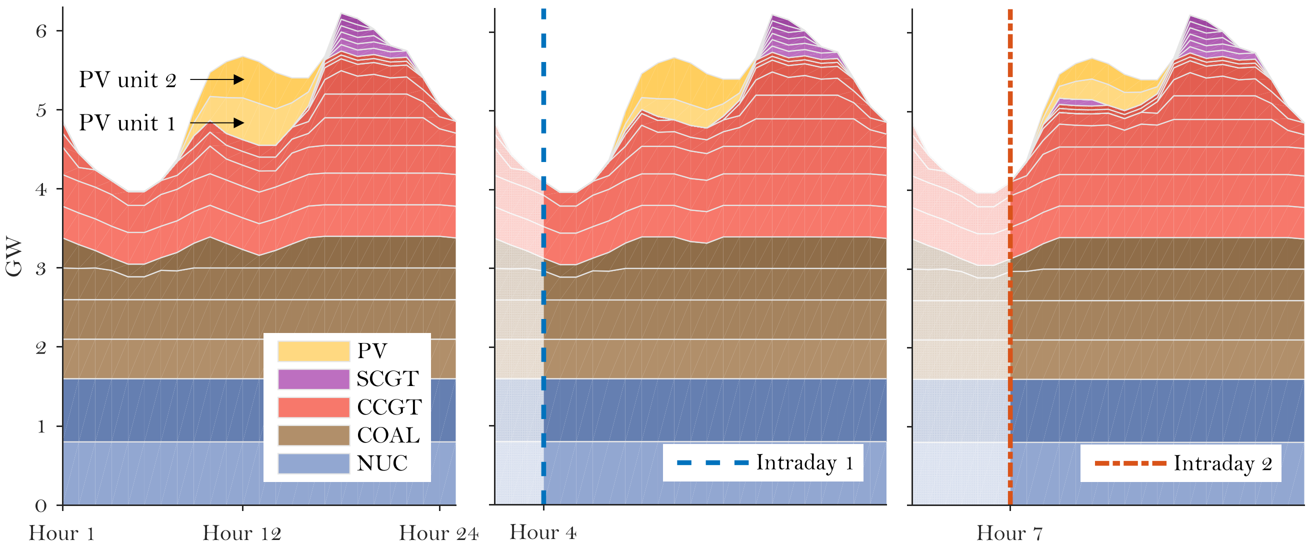
Figure 3 summarizes the tasks performed by the model. The day-ahead market (UC&D model) receives as inputs generation offers (that we assume perfectly competitive), and day-ahead forecasts for RES and load; and outputs day-ahead prices and schedules. The UC&D model is then re-run for each intraday commitment 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 RES 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 generation unit as described in section 3.1.1, taking into account all the previous results.

We apply this model to a stylized case example in order to illustrate the incentives produced by these alternative settlement systems. 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 time scales, both on overall system costs and on the particular economic results of each of these two generators.

4 RESULTS AND DISCUSSION

4.1 Base case

Figure 4 illustrates the case study considered. In the day-ahead market –Figure 4(a)–, both of the 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 two corresponding intraday commitment processes made with hourly resolution for simplicity; the first intraday change takes place in hour 4, once PV unit 1 corrects the forecast to 50% of the initial program –The resulting economic dispatch is shown on Figure 4(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 -see Figure 4(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 1 dispatch (c) Intraday 2/final dispatch

Figure 4: 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 (83% higher in this case example) because of the greater inflexibility found closer to real time. The redispatch cost of each of the corrections is shown on

Figure 5, where the cost is disaggregated in variable and fixed (start-up and no-load cost). Figure 6 shows the marginal price obtained for each of the settlements. Since we consider no other changes than the PV forecast errors, the 'latest' price computed for each period also corresponds in this simplified case to the real-time price.

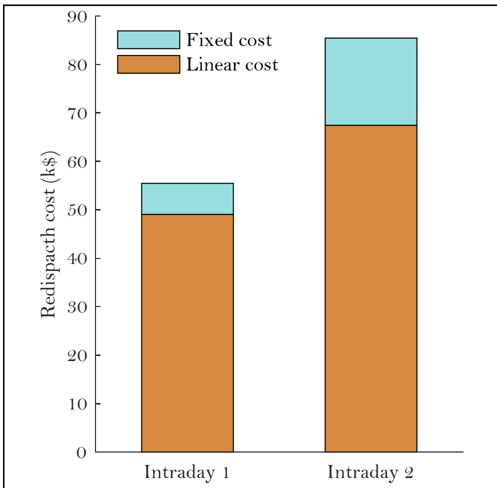


Figure 5: Intraday redispatch cost

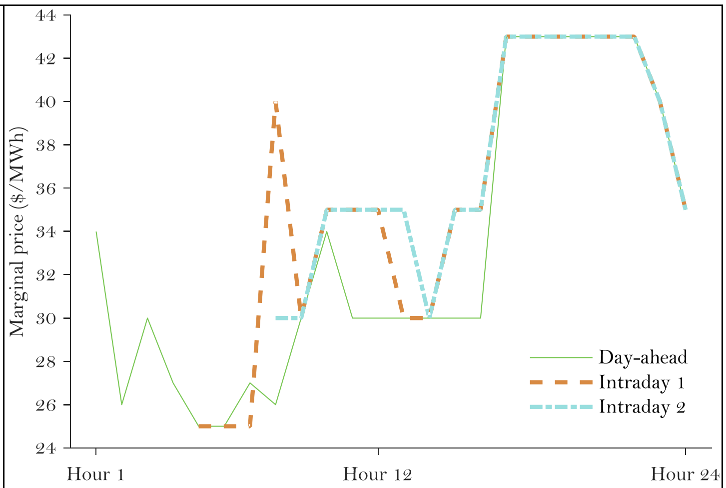


Figure 6: Day-ahead and intraday marginal prices

The final and most relevant result of the model is the settlement for each unit. Figure 7 shows the total revenue for each of the PV units, detailing the source of the incomes (day-ahead market) and charges (real-time or intraday markets), for both the two-settlement and multi-settlement system. Under the multi-settlement system, intraday prices reflect the cost of each of the two forecast deviations, which can then be allocated to each of the units accordingly. Note the marginal price do not capture the whole redispatch cost, and therefore, part of the cost is recovered via uplift. This makes uplift allocation a very relevant part of the settlement system, as described in section 3.1.1, uplift is allocated proportionally to uninstructed deviations to reflect cost causality.

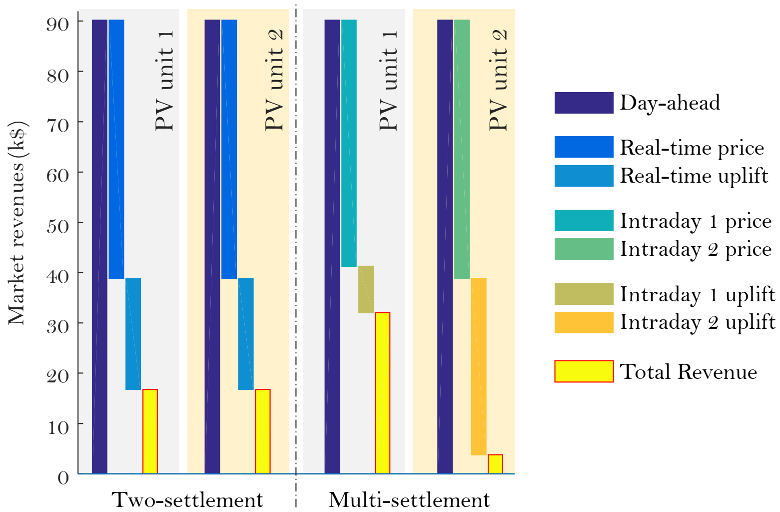
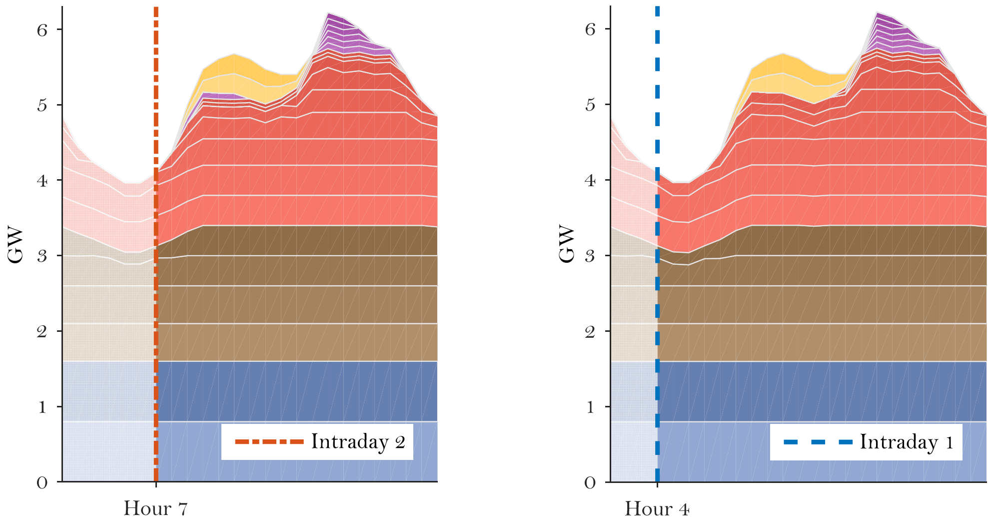


Figure 7: Final settlement for PV units

With the two-settlement system, however, both PV units face the same charges, although unit 1 corrected its forecast much sooner. It over-penalizes unit 1 and under-penalizes unit 2. The multi-settlement system provides results that better reflect the costs produced by the deviation of each plant, which critically depends on when (how early) the deviation was corrected.

4.2 Sensitivity analysis

The desired effect of the proposed settlement system is to incentivize PV units to submit forecast deviations as soon as possible. Therefore, to fully assess the incentive produced by intraday settlements vs the two-settlement system, we can compare the results of the base case with two additional cases (see Figure 8) 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 8: Dispatch result for the additional cases

We compare the revenues earned by each of the PV unit in these two additional scenarios (see Figure 9). We consider the possibility of unit 1 announcing the need to correct their schedule in hour 7 (that is, later than in the base case), and observe the change in its revenue with respect to the base case for both of the settlement systems. The change in revenue represents the incentive for unit 1 not to make the correction later than in the base case. On the other hand, we also evaluate the change in the revenue of unit 2 if it was able to update its forecast in hour 4 (sooner than in the base case). This change in revenue represents the incentive for unit 2 to make the correction sooner.

The results on Figure 9 show the significant difference in the incentive effect produced by each of the settlement systems. The multi-settlement system, which is closely aligned with cost causality principles, sends a clear signal to make forecast corrections as soon as possible.

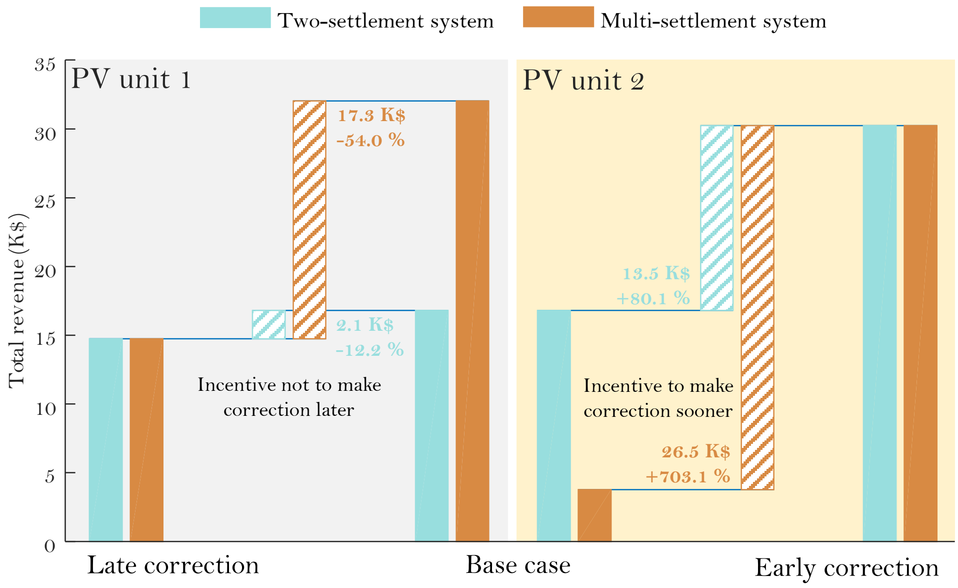


Figure 9: Revenue sensitivity to making forecast corrections later or earlier

5 CONCLUSIONS

ISOs use multiple intraday commitment processes to make dispatch corrections between the day-ahead and real-time markets using gradually updated forecast information. The ISO could benefit from receiving forecast updates directly from producers, which can better account for local conditions, but only to the extent that these agents are appropriately rewarded for the value of accurate forecasting. Although receiving forecast corrections as soon as possible has a clear economic value, under the two-settlement system used in ISO markets this value is not fully disclosed and costs are not properly allocated. To improve the efficiency of the market, each intraday commitment process should be accompanied by its own intraday settlement. This leads to the proposed multi-settlement system, which allows to allocate intraday costs according to cost causality principles, and creates efficient signals for market agents to improve forecast accuracy.

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Annex A. Model formulation

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

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 [$]
$\overline{P}_g$	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]

A.3 Variables

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]

A.3.2 Binary variables:

$u_{g,t}$ Commitment status of unit g at hour t, which is 1 if the unit is online and 0 if offline

$v_{g,t}$ Start-up status of unit g, which is 1 if unit starts-up at hour t and 0 otherwise

$w_{g,t}$ Shut-down status of unit g, which is 1 unit shuts-down at hour t and 0 otherwise

A.4 Formulation

$$\min \sum_{t \in T} \left[\sum_{g \in G} \left[C_g^{NL} u_{g,t} + C_g^{LV} \left(\underline{P}_g u_{g,t} + p_{g,t} \right) + C_g^{SU} v_{g,t} + C_g^{SD} w_{g,t} \right] + C^{NSE} nse_t \right] \tag{A.1}$$

$$s.t. \quad \sum_{g \in G} \left[\underline{P}_g u_{g,t} + p_{g,t} \right] + \sum_{r \in R} PF_{r,t} - pf_t^{spill} = D_t - nse_t \qquad \forall t \tag{A.2}$$

$$\sum_{g} s_{g,t} \geq S_t \qquad \forall t \tag{A.3}$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \qquad \forall g \notin G^{MR}, t \tag{A.4}$$

$$\sum_{i=t-TU_g+1}^{t} v_{g,i} \leq u_{g,t} \qquad \forall g \notin G^{MR}, t \in [TU_g, T] \tag{A.5}$$

$$\sum_{i=t-TD_g+1}^{t} w_{g,i} \leq 1 - u_{g,t} \qquad \forall g \notin G^{MR}, t \in [TD_g, T] \tag{A.6}$$

$$p_{g,t} + s_{g,t} \leq \left(\overline{P}_g - \underline{P}_g \right) u_{g,t} - \left(\overline{P}_g - SU_g \right) v_{g,t} \qquad \forall g, t \tag{A.7}$$

$$p_{g,t} + s_{g,t} \leq \left(\overline{P}_g - \underline{P}_g \right) u_{g,t} - \left(\overline{P}_g - SD_g \right) w_{g,t} \qquad \forall g, t \tag{A.8}$$

$$p_{g,t} + s_{g,t} - p_{g,t-1} \leq RU_g \qquad \forall g, t \tag{A.9}$$

$$p_{g,t-1} - p_{g,t} \leq RD_g \qquad \forall g, t \tag{A.10}$$

$$u_{g,t} = 1, \quad v_{g,t}, w_{g,t} = 0 \qquad \forall g \in G^{MR}, t \tag{A.11}$$

$$pf_t^{spill} \leq \sum_{r \in R} PF_{r,t} \qquad \forall t \tag{A.12}$$

Annex B. Case example data

Table ii shows the data for the thermal generating units considered. The meaning of each parameter is defined in Annex A, except for TS_g which stands for start-up and notification time, and is used as described in section 3.2. 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 ii. 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]	[$]	
NUC1	800	700				50	50			0	7		0
NUC2	800	700				40	40			0	9		0
COAL1	500	200	8	5	6	100	80	200	400	1500	20	90000	0
COAL2	500	200	8	5	6	100	80	200	400	1500	23	90000	0
COAL3	400	160	7	5	5	80	80	160	160	1200	26	70000	0
COAL4	400	160	7	5	5	80	80	160	160	1200	30	70000	0
CCGT1	400	200	4	2	4	200	200	400	500	2000	20	12000	0
CCGT2	400	200	4	2	4	200	200	400	500	2000	25	12000	0
CCGT3	350	175	4	2	4	200	200	300	300	2000	30	12000	0
CCGT4	350	175	4	2	4	200	200	300	300	2000	35	12000	0
CCGT5	300	150	2	2	3	200	200	250	250	1500	40	10000	0
CCGT6	300	150	2	2	3	200	200	250	250	1500	43	10000	0
CCGT7	300	150	2	2	3	200	200	250	250	1500	45	10000	0
CCGT8	100	50	2	1	2	200	200	80	80	600	48	4000	0
CCGT9	100	50	2	1	2	200	200	80	80	600	50	4000	0
SCGT1	100	80	2	1	1	50	50	100	100	2000	75	10000	0
SCGT2	100	80	2	1	1	50	50	100	100	2000	80	12000	0
SCGT3	100	80	1	1	0	50	50	100	100	2000	85	14000	0
SCGT4	80	80	1	1	0	50	50	80	80	1500	90	14000	0
SCGT5	80	80	1	1	0	50	50	80	80	1500	95	15000	0
SCGT6	80	80	1	1	0	50	50	80	80	1500	100	16000	0

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

Table iii: 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