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The impact of short-term pricing on flexible generation investments in electricity markets

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ABSTRACT

The massive growth in the integration of variable renewable energy sources is producing several challenges in the operation of power systems and its associated markets. In this context, flexibility has become a critical attribute to allow the system to react to changes in generation or demand levels. Thus, it is critical for market signals at both short and long term scales to include flexibility features, to align agents' incentives with systemic flexibility requirements. In this paper, different pricing schemes for short-term markets are studied, based on various relaxations of the unit commitment problem, including convex-hull approximations, with the aim of representing operational flexibility requirements in a more explicit way. Extensive simulations illustrate the performance of the proposed schemes, as compared to conventional ones, in terms of the capability of the system to properly incentivize flexibility attributes, resulting in better agents' cost recovery and more variable renewable energy utilization. The results show that short-term pricing schemes considered improve the long-term signals for flexible investments but additional changes to market design are still required. Thus, there is a need to revisit historical practices for pricing rules by incorporating additional flexibility-related attributes into them. Several alternatives are discussed and policy recommendations based on these considerations are provided.

1. Introduction

Greater integration of variable energy sources generates a series of benefits and challenges for the system, at both the operation and market levels. At the operation level, volatility represents one of the main challenges, since the system must be able to withstand these variations. Flexibility is understood as the ability to modify the generation or demand profile quickly enough to balance untimely variations (Cochran et al., 2014; Electric Power Research Institute, 2016). Because of the variable nature of generation, flexibility becomes a relevant and necessary characteristic within any electrical system with large penetration of variable renewable energy (Ulbig and Andersson, 2015; IRENA, 2017). While there are many ways to provide flexibility (Auer and Haas, 2016), one of the main ways is through the deployment of flexible generation units, i.e., units with a great capacity to change their generation from one moment to the next (ramp capability), fast starting-up, among others. Given the expected changes to electric systems, it is necessary to achieve adequate flexibility levels to obtain a system able to take full advantage of the benefits brought by these new renewable technologies.

Significant evidence has been given that the growing integration of renewable energy sources has caused major market challenges and the need to restructure electricity markets (De Vries and Verzijlbergh, 2018; Joskow, 2019a), since many of the assumptions behind the current designs do not necessarily work in scenarios with flexibility requirements, volatile resources or cost structures with low or zero marginal costs, causing sub-optimal decisions (Morales-España et al., 2017). It has been shown that this increase in the need for flexibility intensifies the market problems produced by basic features of power systems models, such as the presence of non-convexities (O'Neill et al., 2005; Fuller and Çelebi, 2017) or the use of a centralized approach in the decision-making, generating a gap between the need for and the incentives to provide flexibility (Traber and Kemfert, 2011; Sioshansi et al., 2008). An example of the lack of alignment between the needs for flexibility and the current market design can be seen in the fact that peaking and highly flexible generators tend to have higher profit variability and risk under variable energy integration (Sioshansi and Tignor, 2012), despite delivering fundamental flexibility to the system.

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Thus, electricity markets need to be updated to integrate well-adapted technologies, reward flexibility and promote long-term investments (IRENA, 2017; Perez-Arriaga and Batlle, 2012).

There is a need to align short-term incentives with long-term objectives. In particular, short-term pricing mechanisms, which deliver energy in an efficient manner, must be aligned with long-term profits of generating units in order to deliver the right mix of generation units, on a low cost and reliable manner. An extra layer of complexity in electricity markets to achieve that alignment is due to the presence of non-convexities such as integer variables in commitment decisions (Vazquez et al., 2017; Mays et al., 2018). A common scheme to tackle these challenges in remuneration is the use of uplift payments, which are payments that help the units to recover their costs by paying any shortfall between incomes obtained from energy and incurred operation costs (Perez-Arriaga and Meseguer, 1997). Although uplift payments are useful to approach the total operation cost recovery, wholesale market schemes are preferred due to their greater transparency using a uniform marginal price for all market agents (Tesfatsion, 2009). In this vein, a market pricing scheme that has been discussed in recent years is the so called convex hull pricing (Bose and Low, 2019). A price signal that better reflects the flexibility delivered by a unit and the associated generation costs, through a convex representation of the total aggregated costs and constraints of the unit commitment problem (Gribik and Pope, 2007) resulting in a modification of the marginal cost of the system and a reduction in the associated uplift payments (IRENA, 2017; Schiro et al., 2015). Implementation is one of the biggest barriers faced by convex hull pricing (Schiro et al., 2015), and multiple approaches have been developed during the last years (Ruiz et al., 2012; Morales-España et al., 2015; Morales-España et al., 2013; Hua and Baldick, 2017). They are based on convex relaxations of the unit commitment problem through time-period polytopes to represent different flexibility associated constraints, such as ramp and min-up/min-down constraints (Pan and Guan, 2016). In any case, the implementation of the exact convex hull ensures the minimization, but not the elimination, of uplift payments (Gribik and Pope, 2007). Thus, the use of a convex hull approximation produces a mixed remuneration scheme where such additional payments seek to be minimized.[2]

In this context, it is relevant to evaluate the long-term impacts of these alternative pricing rules regarding investments. A key issue is to assess how pricing rules that internalize flexibility features can effectively incentivize flexible technologies in the long-run, delivering in efficient ways the flexibility attributes required by the system.

In this paper, we focus on investigating the role of convex hull based pricing schemes on adequately internalizing flexibility into pricing signals, and assess their impact on investments in flexible resources in the long-term. Specifically, the contributions of this paper are summarized as follows:

1. Development of a market model to study the interaction of short-term markets with different pricing schemes, including convex-hull pricing, and their impact on investments.
2. Study of the performance of different pricing schemes to quantify the market incentives for flexible generation using extensive computational experiments for different levels of penetration of renewable energy sources.
3. Discussion of policy implications of the results regarding the need to upgrade short-term market designs and to consider additional mechanisms which take into account flexibility attributes.

The paper is structured as follows. In Section 2, the implemented methodology is detailed. Section 3 presents the unit commitment models and relaxations employed. Section 4 details experimental setup and results for implemented experiments. A discussion of the results application for energy policies is presented in Section 5. Finally, conclusions are presented in Section 6.

[2] A pricing mechanism based on convex hull and average incremental cost pricing which eliminates out of the market payments is proposed in (Chen et al., 2020).

2. Methodology

There is a high level of complexity in the analysis and implementation of electricity markets. Many current market designs are based on assumptions that lose strength when the salient characteristics of electricity systems are considered. This complexity forces a compromise between the level of depth used to analyze market mechanisms and the representation of technical features of power systems.

In order to analyze system flexibility and market incentives together, some simplifications must be made. A four steps methodology is developed to find the mix of generating units induced by different pricing rules, based in the methodology presented in (Herrero et al., 2015). This analysis allows us to circumvent the impossibility of finding an analytic solution to the market equilibrium when detailed physical constraints are considered.

The general steps of the methodology are explained as follows. In Step 1, a benchmark is defined. It corresponds to a centralized planner's problem which optimally selects a generating mix by minimizing investment and operation costs. Then, different mixes of generating units (a combination of different generation technologies) are constructed. Each one is evaluated in Steps 2 and 3. In Step 2 the unit commitment for each mix is simulated. Then, in Step 3, the dispatch decisions and marginal costs obtained in the previous step are used to calculate the remuneration of each of the generation units committed. Finally, Step 4 focuses on finding the generation mixes that would produce an approximate economic equilibrium, where operating units are making positive profits and potential entrants would carry economic losses if they were to enter. A summary diagram of the described methodology is showed in Fig. 1. Full details from each step are given in the next subsections.

2.1. Benchmark: planner's problem

The generating mix that minimizes total cost (construction plus operation) is calculated from a generation planning problem. This benchmark is used as a reference to be compared with the mixes induced by a market under different short-term pricing rules. A convex hull based formulation (eq. 2.1) is implemented in order to include a better representation of flexibility through ramp constraints (Hua et al., 2018). The formulation is similar to the unit commitment problems presented in Section 3, but in this case the number of units to be installed is a variable N_g for each technology g, where its optimal value defines the optimal generation mix. The implemented model is shown below.

Planner's Problem Model

$$\min \quad C^{op}\left(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}\right) + C^{cap}(N_g) \tag{1a}$$

$$\text{s.t.} N_g \geq 0 \quad N_g \in \mathbb{Z}^+ \quad \forall g \in \mathcal{G} \tag{1b}$$

$$\text{Eqs.}(4b)\text{-}(4c), (4i)\text{-}(4j), (8b)\text{-}(8h) \text{ hold} \tag{1c}$$

Parameters and variables are similar to the described in Section 3 models. Decision N_g is added to represent the number of units of the technology cluster g to be constructed. In consequence, parameter C_g^{inv} is added as the annualized capital cost of an installed MW of technology g. Total operating costs are represented as: $C^{op}\left(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}\right) = \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}}\left[C_g^{NL}u_{g,t} + C_g^{LV}p_{g,t} + C_g^{SU}v_{g,t} + C_g^{SD}w_{g,t}\right] + C^{LS}d_t^{LS}$ and the total capital costs are given by: $C^{cap}(N_g) = \sum_{g\in\mathcal{G}}C_g^{inv}N_g$.

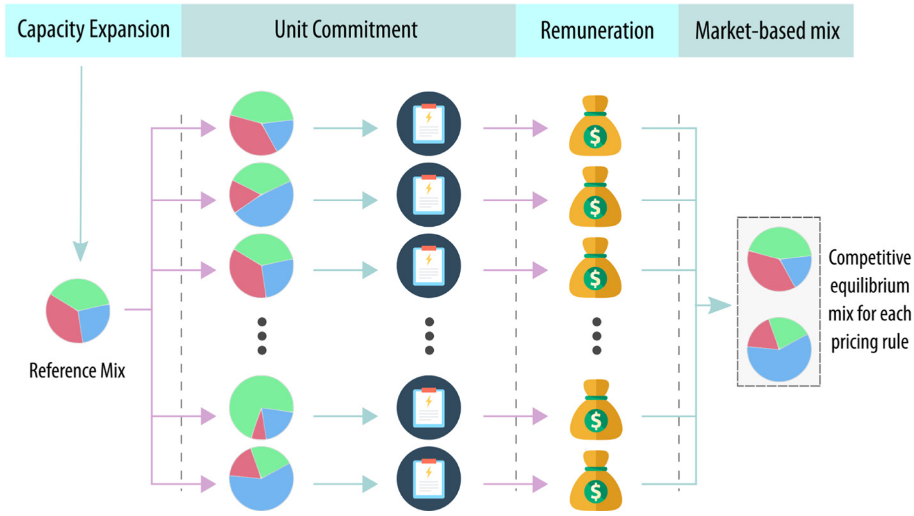


Fig. 1. Implemented methodology summary diagram.

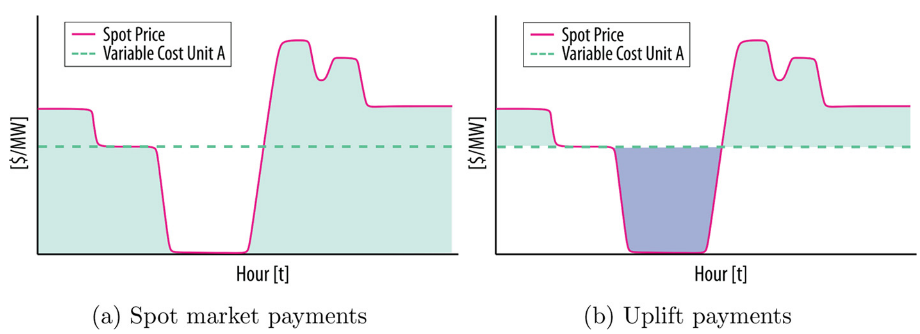


Fig. 2. Diagram of short-term schemes remuneration. Total payment received from spot markets (green) is shown in (a). Uplift payments (green area minus blue area) results from the difference between spot price remuneration and variable cost during a period of time, ensuring that generators recover, at least, their operation costs during that period.

2.2. Unit commitment

A set of generation mixes is obtained from possible combinations of the generation technologies under consideration, as described in (Herrero et al., 2015). A unit commitment problem is applied to each combination to determine operation and dispatch decisions for that mix. Then, the minimization problem is solved again using different relaxations of the unit commitment problem to obtain marginal cost information. In summary, operation decisions for each mix and marginal cost for each formulation and mix are the outputs of this module.

2.3. Remuneration

As in (Herrero et al., 2015), marginal costs obtained from the previous step are used to compute the remuneration received by generation units[3] under each pricing rule for each mix. It is important to note that the same dispatch decisions of a mix are used for each type of pricing.

The total remuneration of a unit in a period is defined by eq. 2, as the sum of total spot-market and uplift payments in that period. In this paper, four different spot-market payments will be studied, obtained from the formulations presented in Section 3. Also, for each of these cases, the impacts of uplift payments will be considered by applying uplift payments with different time horizons for its calculation: daily and hourly basis.

$$\sum_{t \in T} \boldsymbol{\pi}_t P_{g,t} + SP_{g,T} \tag{2}$$

For the spot-market payments, a uniform marginal price π_t is defined by the dual variable ρ_t obtained from each pricing rule scheme, representing the system value of the dispatched energy for every time point t. Then, the total remuneration by spot-market prices is determined by the amount of energy supplied to the system at a certain uniform price for each time point t, expressed as $\sum_{t \in T} \boldsymbol{\pi}_t P_{g,\,t}$ and depicted in Fig. 2a.

Sometimes, operational conditions generate a marginal price that does not recover all of the operation cost of some generating units. Then, uplift payments are applied to construct the payment needed when the uniform price π_t is not enough to compensate for all the operation costs, incurred in a certain period of time. The main objective of this mechanism is to ensure for each dispatched generator the recovery of, at least, their operation costs. The calculation is based on the positive difference between the incurred operation costs of a unit and its uniform-priced remuneration perceived during a period of time T, as shown in eq. 5 and depicted in Fig. 2b, where the horizon T used for calculation could be hourly, daily, weekly, etc. It must be noted that we follow the same uplift definition as in (Herrero et al., 2015). Other

[3] The methodology assumes an equitable distribution of the payments between units of the same technology

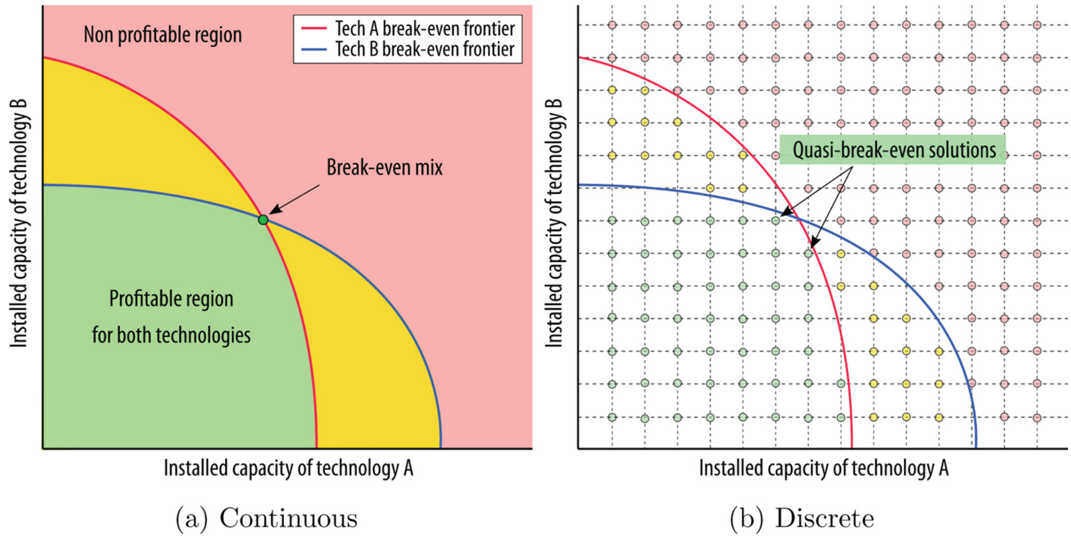


Fig. 3. Set of possible mixes when continuous investment decisions are allowed (a) and when investment decisions are discrete (b) (Herrero et al., 2015).

definitions of uplifts are available in the literature and could also be evaluated using this methodology.

$$SP_{g,T} = \max\left(0, \sum_{t \in T} C^{op}_{g,t}\left(p_{g,t}, u_{g,t}, v_{g,t}, w_{g,t}\right) - \boldsymbol{\pi}^{\boldsymbol{t}} P_{g,t}\right) \tag{3}$$

2.4. Search of market-based mix

From the comparison of the remunerations obtained for each capacity installed mix, the market-based mix is defined as the mix that each pricing rule encourages. It is important to note that each generator of the system is considered as a price taker agent that tries to maximize its own profit. In the long-term, the main purpose is that price signals encourage the investment in new energy at the right place and moment.

On this way, profitable mixes are selected from all the simulated combinations, i.e. the mixes where all generators recover their total costs (capital and operating) with the obtained remunerations. As discussed in (Herrero et al., 2015), it is relevant to consider that when continuous investment decisions are allowed, a break-even frontier for each technology can be found, as shown in Fig. 3a. Break-even is understood as the exact number of units that need to be installed for obtain remunerations that exactly equal the total costs for each unit. On this way, the market-based mix results from the intersection between the break-even frontiers of the respective technologies.

Since investment decisions are discrete, reaching the break-even mix is not possible (Herrero et al., 2015) and an approximate discrete combination of this break-even mix must be found. Then, quasi break-even mixes are defined as points that are profitable for all the generation units and are close to the continuous break-even frontier, as shown in Fig. 3b. Thus the market entry of any additional unit will cause the exit of another unit. In this way, quasi-break even mixes represent a potential market equilibrium where the entry opportunities for new actors are exhausted. As also shown in Fig. 3b, multiple points could meet with those conditions, but in this work only the mix that maximizes the net social benefit for the system will be chosen as the market-based mix.

3. Models

Different formulations proposed in the literature for Unit Commitment (UC) models are studied to observe their behavior in scenarios of need for system flexibility. Models with different types of relaxations (i.e., no relaxations, linear and two convex-hull based relaxations) are used to evaluate different short-term pricing schemes. In addition, the model without relaxations (Model 3.1) is also used to quantify the commitment and dispatch of the generating units. In particular, there are described four models:

- Non-Linear: It considers a full Unit Commitment model with clustering to improve the computational time. This model is used for evaluating the short-term system operation (i.e., commitment and dispatch). In addition, this model is also used to quantify prices by fixing the integer variables to their optimal integer values.
- Linear: This model is used to quantify prices by assuming that integer variables are relaxed.
- Convex Hull A: This model is used to quantify prices by assuming convex hull relaxations with three commitment variables.
- Convex Hull B: This model is used to quantify prices by assuming convex hull relaxations with two commitment variables.

A detailed description of each of these models is presented next.

3.1. Technology clustered unit commitment

In order to reduce computational times for the implemented simulations a technology clustered integer unit commitment, as proposed in (Gollmer et al., 2000) and implemented in (Palmintier and Webster, 2011), is utilized. In particular, it allows the clustering of thermal units by technology (van Stiphout et al., 2017), producing a reduction in the number of integer variables and a reduction in computational times, which is relevant when a large number of simulations are required. The resulting model is presented below.

Model 1: Non Linear Model

$$\min \; C^{op}(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}) \tag{4a}$$

$$\text{s.t.} \; \sum_{g\in\mathcal{G}} p_{g,t} - p_t^{EC} = D_t - d_t^{LS} \;\; \forall t \in \mathcal{T} \quad \perp \boldsymbol{\rho_t} \tag{4b}$$

$$\underline{P}_g u_{g,t} \le p_{g,t} \le \overline{P}_g u_{g,t} \;\; \forall t \in \mathcal{T}, g \in \mathcal{F} \tag{4c}$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \;\; \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{4d}$$

$$p_{g,t} - p_{g,t-1} \le R_g u_{g,t-1} + R_g^{su} v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{4e}$$

$$p_{g,t-1} - p_{g,t} \le R_g u_{g,t} + R_g^{su} w_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{4f}$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g \;\; \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{4g}$$

$$u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{Z} \;\; \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{4h}$$

$$p_{g,t} = \alpha_{g,t}\overline{P}_g \;\; \forall t \in \mathcal{T}, g \in \mathcal{R} \tag{4i}$$

$$p_t^{EC} \le \sum_{g\in\mathcal{R}} p_{g,t} \;\; \forall t \in \mathcal{T} \tag{4j}$$

$$p_{g,t}, d_t^{LS}, p_t^{EC} \ge 0 \;\; \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{4k}$$

$$p_{g,t}, d_t^{LS}, p_t^{EC} \in \mathbb{R} \;\; \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{4l}$$

Here, $\mathcal{G}, \mathcal{F}, \mathcal{R}, \mathcal{T}$ are the sets of generating technologies, fuel generating technologies, renewable generating technologies and hourly periods respectively. The decisions are $u_{g,t}$, $v_{g,t}$, $w_{g,t}$, $p_{g,t}$, d_t^{LS}, p_t^{EC}.

Decisions $u_{g,t}$, $v_{g,t}$ and $w_{g,t}$ are integer variables that represent the number of online, starting-up, and shutting-down units for technology g at time point t, respectively. Decisions $p_{g,t}$, d_t^{LS} and p_t^{EC} correspond to linear variables that represent the power generation from technology cluster g, load shedding and curtailment of renewable energy at time point t, respectively. Parameters of generation, no load, start-up and shut-down costs are given by C_g^{LV}, C_g^{NL}, C_g^{SU}, C_g^{SD}. Additionally, C^{LS} represents the load shedding penalty for the system; $\alpha_{g,\,t}$ is a capacity factor between 0 and 1, which represents the resource availability for variable generator g in time point t, $\overline{P}_g$ and $\underline{P}_g$ are maximum/minimum generation limits; R_g is the maximum up/down ramp limit between consecutive operating time points; R_g^{su} is the maximum up/down ramp limit when a start-up or shut-down occurs; N_g is the number of installed units of g technology; and D_t stands for the hourly system demand. ρ_t is the dual variable associated to the power system balance eq. (4b) that represents the marginal cost of the system for each time point t. For this case, ρ_t is calculated from the linear problem resulting of presolving Model 1 and then fixing integer variable values at their optimal value.

$$C^{op}\left(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}\right) = \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}}\Big[C_g^{NL}u_{g,t} + C_g^{LV}p_{g,t} + C_g^{SU}v_{g,t} + C_g^{SD}w_{g,t}\Big] + C^{LS}d_t^{LS} \tag{5}$$

Objective function (4a) represents the total operating cost, that is defined by eq. 5. System power balance is represented by constraint (4b) allowing load shedding and energy curtailment from renewable sources. Constraints (4c) - (4d) represent generation limits and the temporal logic between the number of online units, number of units starting up and number of units shutting down. Ramp constraints are defined by (4e) - (4f), (4 g) restricts possible values of online units to the number of installed units, (4 h) defines the natures of integer variables. Constraint (4i) ensures that renewable generation is restricted by the corresponding capacity factor, (4j) allows the option to make curtailment from renewable sources according to real generation from these technologies. Finally, (4 k) and (4 l) are the bounds and nature of the linear variables associated to power generation, load shedding and curtailment.

3.2. Relaxed clustered integer unit commitment

A first approach to include flexibility on pricing rules consists in the relaxation of the binary variables of the original problem, as presented in the model defined in eq. 6. This change means that some units are partially dispatched and variable and fixed costs are considered at the same time, which makes its fixed costs behave like variables. The incorporation of operational attributes in marginal prices is produced through this formulation.

Model 2: Linear Model

$$\min \ C^{op}(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}) \tag{6a}$$

$$\text{s.t. } p_{g,t} - p_{g,t-1} \le R_g u_{g,t-1} + R_g^{su} v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{6b}$$

$$p_{g,t-1} - p_{g,t} \le R_g u_{g,t} + R_g^{su} w_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{6c}$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g \quad \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{6d}$$

$$u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{R} \quad \forall t \in \mathcal{T}, g \in \mathcal{G} \tag{6e}$$

$$\text{Eqs. (4b)-(4d), (4i)-(4l) hold} \tag{6f}$$

3.3. Tight approximation of convex hull with three commitment variables

In this model a tight approximation of the convex hull relaxation of the UC is considered (Damcı-Kurt et al., 2016). On this way, ramp constraints and UC temporal balance constraints are relaxed through a 2 time-period polytope, as shown in eqs. (7b-7f).

Model 3: Convex Hull-A Model

$$\min \ C^{op}(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}) \tag{7a}$$

$$\text{s.t. } p_{g,t} - p_{g,t-1} \le \left(\underline{P}_g + R_g\right) u_{g,t} - \underline{P}_g u_{g,t-1} - \left(\underline{P}_g + R_g - R_g^{su}\right) v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7b}$$

$$p_{g,t} \le \overline{P}_g u_{g,t} - \left(\overline{P}_g - R_g^{su}\right) v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7c}$$

$$p_{g,t-1} \le \overline{P}_g u_{g,t-1} - \left(\overline{P}_g - R_g^{su}\right) w_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7d}$$

$$p_{g,t-1} - p_{g,t} \le \left(\underline{P}_g + R_g\right) u_{g,t-1} - \underline{P}_g u_{g,t} - \left(\underline{P}_g + R_g - R_g^{su}\right) w_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7e}$$

$$0 \le u_{g,t} \le N_g, 0 \le v_{g,t}, 0 \le w_{g,t} \quad t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7f}$$

$$u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{R} \quad t \in \mathcal{T}/1, g \in \mathcal{G} \tag{7g}$$

$$\text{Eqs. (4b)-(4d), (4i)-(4j) hold} \tag{7h}$$

3.4. Tight approximation of convex hull with two commitment variables

Assuming that the shutdown costs are zero, a simpler version of the model 7 can be used (Hua and Baldick, 2017), thus reducing the dimensions of the associated optimization problem by using only the commitment variables that represents online and starting-up units, giving advantages for its real implementation by having shorter calculation times in large problems (Hua et al., 2018).

Model 4: Convex Hull-B Model

$$\min \; C^{op}(p_{gt}, u_{gt}, v_{gt}, w_{gt}, d_t^{LS}) \tag{8a}$$

$$\text{s.t. } u_{g,t} - u_{g,t-1} <= v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8b}$$

$$p_{g,t} - p_{g,t-1} \leq \left(\underline{P}_g + R_g\right) u_{g,t} - \underline{P}_g u_{g,t-1} - \left(\underline{P}_g + R_g - R_g^{su}\right) v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8c}$$

$$p_{g,t} \leq \overline{P}_g u_{g,t} - \left(\overline{P}_g - R_g^{su}\right) v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8d}$$

$$p_{g,t-1} \leq R_g^{su} u_{g,t-1} + \left(\overline{P}_g - R_g^{su}\right)\left(u_{g,t} - v_{g,t}\right) \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8e}$$

$$p_{g,t-1} - p_{g,t} \leq R_g^{su} u_{g,t-1} - \left(R_g^{su} - R_g\right) u_{g,t} - \left(\underline{P}_g + R_g - R_g^{su}\right) v_{g,t} \quad \forall t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8f}$$

$$0 \leq u_{g,t} \leq N_g, 0 \leq v_{g,t} \quad t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8g}$$

$$u_{g,t}, v_{g,t} \in \mathbb{R} \quad t \in \mathcal{T}/1, g \in \mathcal{G} \tag{8h}$$

$$\text{Eqs. (4b)-(4c), (4i)-(4j) hold} \tag{8i}$$

4. Computational experiments

This section presents several computational experiments comparing the pricing rules outcomes with the purpose of understanding how these different rules could be aligned with long-term objectives of the system, particularly related to flexible resources. Similar to related works (Vazquez et al., 2017; Mays et al., 2018; Herrero et al., 2015), we use a uni-nodal system which simplifies the implementation of the experiments and interpretation of the results, without the need to consider spatial dimensions. Three representative generation technologies are constructed in order to represent units with different capacity to provide flexibility through their ramp restrictions. In this way, 'Base', 'Cycling' and 'Peaking' units are modeled based on the characteristics and costs indicated in (Herrero et al., 2015; Black, 2012). The implemented parameters are shown in Table 1.

Demand profile and capacity factors for renewable energy sources are taken from (Lab, 2018) as representation of the Chilean power system with total annual load of 71.719 GWh, with a peak-load of 9.824 GW and a bottom-load of 6.375 GW. Installed capacity of solar and wind units are also based in the Chilean case, with 2368.16 MW and 1489.19 MW of solar and wind generation capacity, respectively (Coordinador Electrico Nacional, 2019). Load shedding value was set at 1000 US$/MWh.

Table 1
Generation technologies characteristics.

Technology	Max. Cap. [MW]	Min. Cap. [MW]	Up/dn Ramp [MW/h]	Su/Sd Ramp [MW/h]	C^{LV} [US$/MWh]	C^{NL} [kUS$/h]	C^{SU} [kUS$]
Peaking	150	60	72	72	104	1.65	14.75
Cycling	400	160	20	160	57	2.44	28.33
Base	1000	500	0	500	8.5	1.5	–

A full year of real data is used to generate daily operational profiles for load and renewable capacity factors for generation expansion planning problems. Then, a clustering technique was applied over the 365 daily profiles in the base year for the study cases, next 6 clusters were obtained for be applied as representative days in each simulation of the UC problem (See section 2.2). Each representative day is associated to its own daily operational profile.

All experiments have been implemented in Python, using the Pyomo package for optimization modeling. Gurobi was employed for solving mixed-integer optimization problems with an optimality gap of 1.0% for the planning problem described in section 2.1, 0.1% was used for the simulations of the UC described in section 2.2. All experiments have been performed in a Dell PowerEdge R360 server with an Intel Xeon CPU E5–2630 v4 processor running at 2.20GHz, and 64 GB of RAM.

4.1. Experiment 1: synthesis of reference mix

This part studies the optimal amount of constructed units obtained by the generation planning problem, assuming that the system is constructed from zero and focusing on the operation of the final planning period through the use of annualized investment costs. To perform this analysis, real data for 365 days are used to generate daily operational profiles for load and renewable capacity factors. Using these data, a UC problem is solved for every day over the whole planning horizon, under three levels of variable sources integration: solar and wind integration, only solar, and no renewable integration, where variable sources installed capacity has been previously defined. Through this experimental setup, total annualized capital and operating costs of the generation planning problem and optimal mix configuration is obtained for the representative year.

The resulting generation capacity mixes at the end of the planning horizon, obtained for each level of renewable integration, are shown in Fig. 4. As expected, it can be observed an increment in the number of flexible generation units and the total installed capacity between the levels of renewable integration. These changes are produced due to a system need for being prepared for high levels of operational

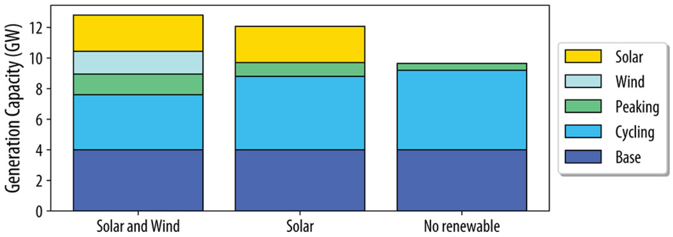


Fig. 4. Generation capacity mix under different cases of renewable sources integration.

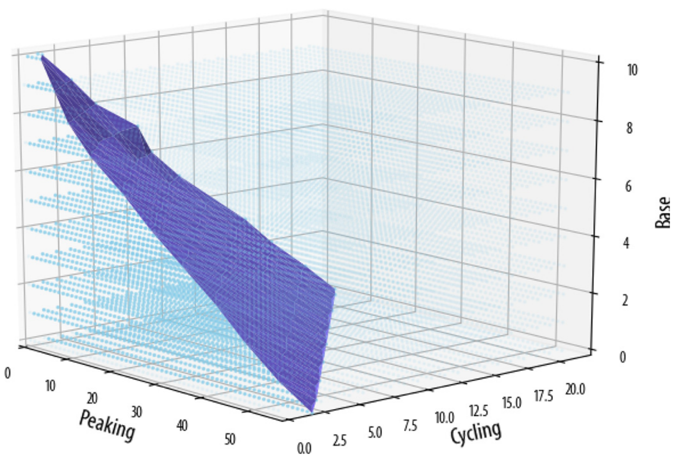


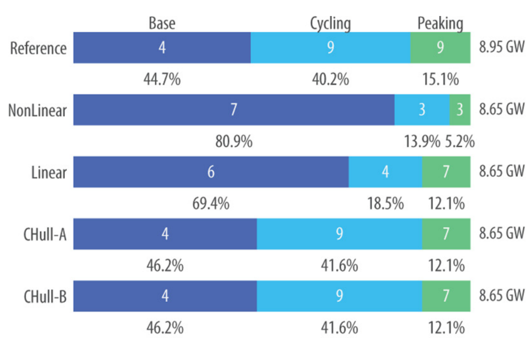
Fig. 5. Break-even surface is obtained from set of all profitable and simulated combinations of capacity installed generation.

uncertainty, resulting from the renewable integration, which leads to additional investment in flexible generation resources.

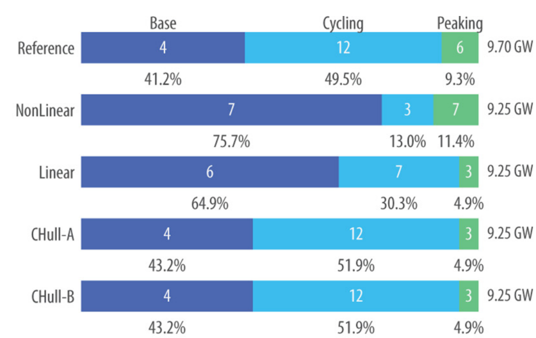
4.2. Experiment 2: market-based mix through short-term incentives

From the optimal mix obtained in the previous experiment, we proceed to look for the incentivized mixes through each pricing rule under study. A set of possible combinations is built, generating 20,306 potential solutions. The methodology described in section 2.2 and section 2.3 is applied to each of these combinations, generating a break-even surface from the profitable combinations, as shown in Fig. 5. From this surface, the market-based mix encouraged by each pricing rule incentive is obtained by applying the methodology described in section 2.4. In this way, this experiment studies the differences among the generation mixes encouraged by each pricing rule.

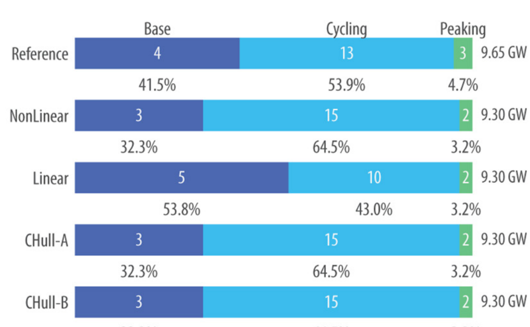
Market-based mix produced for the solar and wind integration case are shown in Fig. 6a. It can be observed that the incentivized mixes resulting from the four applied pricing schemes deviate from the reference mix, evidencing that none of the pricing rules is capable to provide sufficient remunerations for making profitable all the units. In fact, not only the composition of the market-based mix varies with respect to the references, but the total installed capacity in each case suffers a reduction from the optimal reference capacity mix. In general, it is noted that the difference between the market-based mix and the reference mix is lower when the applied pricing rule is based on approximations of the convex hull. The same effects can be observed for the cases of solar integration and no renewable integration (see Fig. 6b and c), but it is possible to see that in the no renewable integration case, the mix encouraged by the Non-Linear pricing rule is equal to the mix obtained by CHull-A and CHull-B pricing rules. This is because since the convex hull captures part of the flexibility of the system, the differences are



(a) Solar and wind integration



(b) Solar integration



(c) No renewable integration

Fig. 6. Market-based mix results for different levels of renewable integration compared to planning problem reference. Reference is the optimal benchmark solution determined by the centralized Planner's Problem Model presented in Section 2.1.

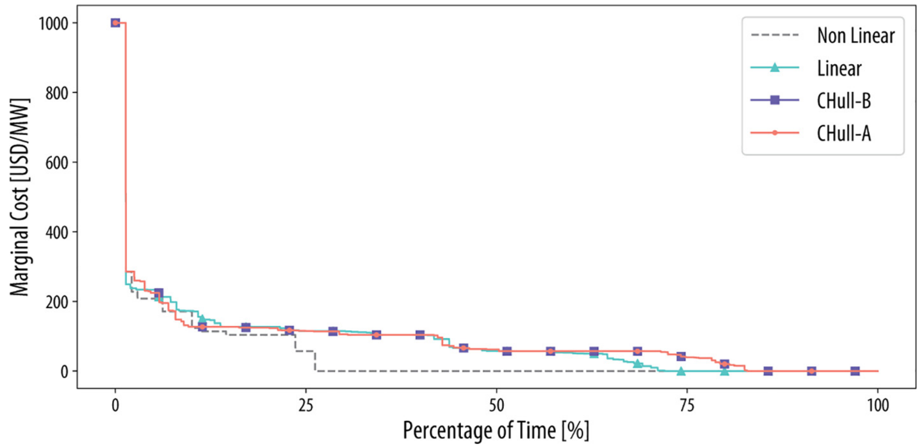


Fig. 7. Market prices for different pricing schemes considering solar and wind integration and market incentivized mixes.

more visible when convex hull pricing is applied to a system with higher volatility in its net demand. This high volatility in net demand can be the product of the amount of renewable energy (as in this case) or even by a different behavior of demand.

The marginal cost is one of the variables of interest in the analysis of the functioning of the electrical system, since its value defines the remunerations from the spot market. Market prices for the case in which solar and wind integration is considered are shown in Fig. 7. As expected, the use of the proposed pricing rules in models 3.2 to 3.4 entails an increase in the value of the marginal price, because the dual variable of these problems not only integrates variable costs but also the impact of non-convexities, internalizing in the marginal signals flexibility dimensions of the system operation.

Table 2 shows the total operating costs and annualized investment costs obtained by simulating the unit commitment of each market-based mix obtained and the difference in percentage with respect to reference benchmark, for the case of solar and wind integration. It can be observed that all the mixes deliver a higher cost than that obtained by the reference mix; however, it can be noted that lower costs are produced with the use of pricing rules based on some relaxation. The same outcome occurs in the case of solar integration, while the case of no renewable integration does not require further analysis since almost the same market-based mix is obtained by each pricing rule.

The small differences that occurs between pricing rules could lead to a debate about whether it is really worth the application of these alternative pricing schemes. To answer this concern, it is necessary to remember that the objective of the alternative pricing schemes enunciated in the Section 3 is to incorporate aspects of flexibility into the problem, that is, that the system is appropriate for variable generation sources and at the same time, get the most out of these technologies. In this way, Table 3 shows the amount of renewable sources curtailment that is made in each encouraged mix and the relation with the total available variable sources generation. The fact that, for renewable integration cases, the level of curtailment in a non-linear market-based mix exceeds 10 and 15% of the total renewable energy available, respectively, is key. Meanwhile, the use of a pricing rule based on a relaxation of UC provides better use of these units, where the curtailment does not exceed 2% of the available energy, proving that these schemes encourage more flexible generation mixes for the system.

It is important to note that identical results are obtained under the use of the CHull-A and CHull-B models, which generates interesting insights for an eventual application within a real system, due to the smaller number of variables used by the second model.

4.3. Experiment 3: performance of pricing rules and uplift payments in reference mix

It is also interesting to analyze the behavior and effects of the different pricing rules when they are applied in the optimal reference mix given by the generation planning problem. Specially, to gain insights into which type of units are more impacted. For this part, the behavior of the marginal costs, the uplift payments and the way in which the units recover their total costs under each price scheme will be studied. Although the results were obtained for all cases of integration of renewable sources, the discussion of this experiment will focus on the optimal mix obtained by the solar and wind integration case.

Similar to the results of the previous experiment, the use of the proposed pricing rules in models 3.2 to 3.4 entails an increase in the value of the marginal price. In this way, the average marginal price increases according to the used pricing rule, being 69.9, 79.15, 79.18 $/MW for non linear, linear and convex hull relaxations, respectively. In any case, Fig. 8a shows how despite the rise in the average, the behavior of marginal prices remains very similar between the different pricing rules during the year of operation represented. This figure also shows that, unlike the prices for the market incentivized mixes presented in Section 4.2, under the reference mix prices are never up to the level of the value of load-shedding.

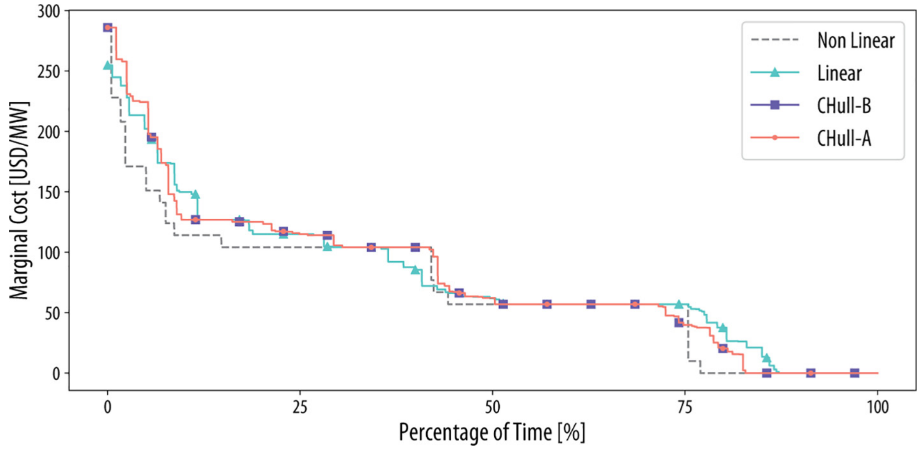
When uplift payments by unit are analyzed, it can be observed in Fig. 8b that when these payments are defined in an hourly basis, the

Table 2
Costs under different market-based mixes.

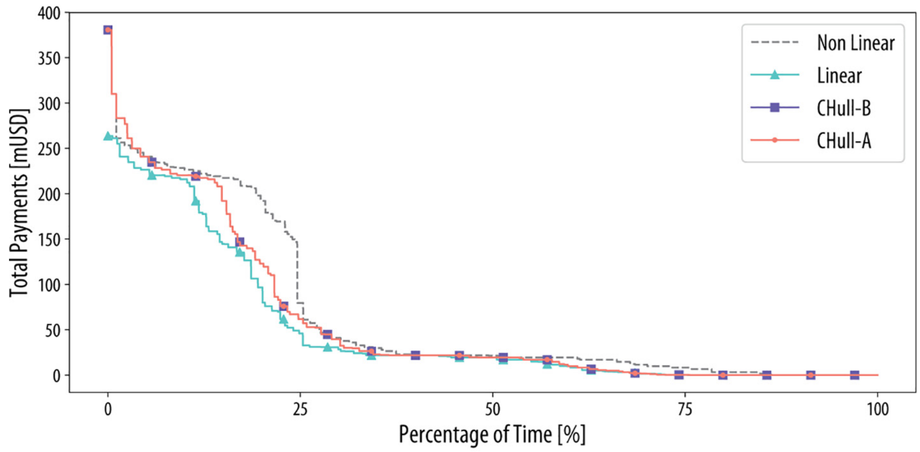
Pricing Rule	Total Cost [MM $]	Dif. from Ref. mix	Op. Costs From Total Costs	Load Shedding
NonLinear	5396.69	+2.63%	19.6%	0.008%
Linear	5341.49	+1.58%	27.9%	0.006%
CHull-A	5336.75	+1.49%	44.6%	0.006%
CHull-B	5336.75	+1.49%	44.6%	0.006%

Table 3
Curtailment from renewable energy sources under different market-based mixes.

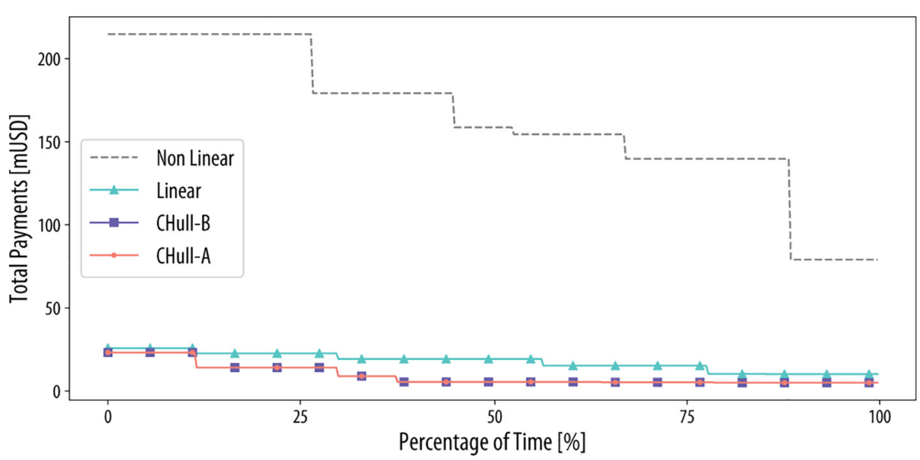
Solar and wind case	NonLinear	Linear	CHull-A	CHull-B
Total curtailment [GWh]	1505.2	508.6	136.9	136.9
% from available ren.	17.87%	6.04%	1.62%	1.62%
Solar case	NonLinear	Linear	CHull-A	CHull-B
Total curtailment [GWh]	453.6	222.3	76.5	76.5
% from available ren.	10.58%	5.18%	1.78%	1.78%



(a) Marginal cost



(b) Hourly uplift payments



(c) Daily uplift payments

Fig. 8. Operational performance of different pricing rules applied in the reference mix.

total uplift remuneration have a similar profile under each price rule with a slight decrease when pricing rules based on relaxation are applied. A total of 587.6 MM$ in uplift payments should be paid when non-linear pricing is used. When linear pricing or convex hull are applied, a 26.3% and 14.6% reduction is observed, respectively. Greater

Table 4
Uplift payments as percentage respect to spot-market payments for each pricing rule.

Pricing rule basis	Non linear	Linear	CHull-A	CHull-B
Hourly	11.38%	7.37%	8.53%	8.53%
Daily	1.16%	0.11%	0.06%	0.06%
Spot-Market Payments (MM USD)	5164.9	5876.9	5885.9	5885.9

Table 5
Total payments for each pricing rule and hourly side payments.

Payments (MM USD)	Non linear	Linear	CHull-A	CHull-B
Side Payments	587.6	433.3	501.9	501.9
Spot-Market Payments	5164.9	5876.9	5885.9	5885.9
Total Payments	5752.5	6310.2	6387.8	6387.8

benefits of using an approximation of the convex hull to define the price scheme can be observed in Fig. 8c. When the uplift payments are defined on a daily basis (equivalent to the horizon used for the calculation of the UC problem) there is a notable reduction of payments in all the price schemes. Aligned with the fact that the greater effectiveness of convex hull pricing is achieved when the same horizon as the commitment problem is used (Schiro et al., 2015). As example, non-linear pricing produces a total of 56.69 MM$ in uplift payments, that is, less than 10% of the amount produced when hourly uplift payments are used. This is because when considering a shorter time horizon, whenever there is a period where the marginal cost is lower than the variable costs, the generator must be remunerated. On the other hand, when considering a longer time horizon, the possibility that the supra-marginal periods are compensated with infra-marginal periods, achieves a reduction in the amount of uplift payments. In addition, the difference between pricing rules is also more remarkable from Fig. 8c: there is a reduction of uplift payments in relation to the Non-Linear case of 89.1% and 94.4% when linear and convex hull pricings are applied, respectively. Table 5 summarizes the total payments when hourly side payments are considered, Table 4 summarizes the differences between the uplift payments produced by each pricing rule, showing how they behave in relation to the total spot-market payments, the best reduction in payments is observed when daily uplift payments and a convex hull pricing are applied.

Finally, Table 6 shows that regardless of the price rule used, only Base and Cycling units achieve total recovery of their operating and investment costs, which not happen for units that provide more flexibility to the system (Peaking). This means that, even the application of pricing schemes that internalize flexibility costs, might not be enough to produce proper entry signals to new investments. A deeper analysis is shown in Table 7, where only the operating costs are compared with the short-term remuneration schemes. It is observed that when daily basis uplift payments are applied, all units at least recover exactly their operating costs. On the other hand, the use of hourly basis uplift payments causes an over payment that do not materialize into a significant improvement in the total costs recovery (investment and operation), as previously seen in Table 6.

5. Policy discussion

As mentioned, the deployment of variable renewable sources has brought a series of challenges at both the operation of power systems and its markets. At the market dimension, the different cost structure of renewables regarding marginal costs, and the need to cope with volatility and uncertainty by having a flexible system require the development of new market designs and pricing schemes. Moreover, as several authors have pointed out (Joskow, 2019b; Roques and Finon, 2017; Newbery et al., 2018), the notion of hybrid markets with competition *for* and *in* the market might be required to face these challenges.

The results of this work provide several insights that illustrate the need to change pricing schemes and quantify the impact of different solutions. First, there is an impact of short-term pricing schemes in the long-term signals for investment in flexible resources. In particular, convex hull-based schemes do capture flexibility features of power systems that are internalized into the short-term prices, generating short-term incentives better aligned with long-term objectives. These results complement other results available in the literature, not focused on flexibility issues, which also illustrate that pricing schemes based on the modification of marginal signals provides better long-term outcomes (Vazquez et al., 2017; Mays et al., 2018). Second, it can be observed that none of the combinations of pricing rules and uplift payments evaluated manage to align the incentives for new investments with the system needs of flexibility. Thus, additional design elements must be incorporated into electricity markets, making the questions about the timescale (e.g., short- long-term) and nature (e.g., competition for- in- the market), among other features of these elements, relevant.

Regarding the short-term pricing schemes evaluated in this work, the results show that under the assumptions considered there is a small difference in total operation and investment costs that results between the several pricing rules analyzed. This can lead to a relevant policy discussion about whether it is really worth the application of these new pricing schemes. Similarly, the possible increments in marginal energy prices, which is a natural and expected outcome, or the possible

Table 6
Total cost recovery by technology under different pricing rules.

Technology	Peaking			Base			Cycling		
Side payment	None	Daily	Hourly	None	Daily	Hourly	None	Daily	Hourly
Non Linear	52.8%	68.6%	72.2%	90.4%	90.4%	93.3%	88.4%	88.7%	107.9%
Linear	66.6%	68.6%	79.4%	102.3%	102.3%	104.1%	101.2%	101.2%	116.3%
ConvexHull-A	67.6%	68.6%	80.9%	102.4%	102.4%	104.6%	101.5%	101.5%	118.9%
ConvexHull-B	67.6%	68.6%	80.9%	102.4%	102.4%	104.6%	101.5%	101.5%	118.9%

Table 7
Operating Cost recovery by technology under different pricing rules.

Technology	Peaking			Base			Cycling		
Side payment	None	Daily	Hourly	None	Daily	Hourly	None	Daily	Hourly
Non Linear	77.0%	100.0%	105.3%	699.0%	699.0%	722.0%	114.3%	114.7%	139.5%
Linear	97.2%	100.0%	115.8%	791.5%	791.5%	805.0%	130.8%	130.8%	150.3%
ConvexHull-A	98.5%	100.0%	118.0%	791.8%	791.8%	809.2%	131.2%	131.2%	153.7%
ConvexHull-B	98.5%	100.0%	118.0%	791.8%	791.8%	809.2%	131.2%	131.2%	153.7%

implementation costs might become an obstacle at the moment of their real implementation.

It should be noted that the convex hull models produce a solution that seems more expensive than that the delivered one by the current pricing models. However, we must consider the impact of these schemes on all the other dimensions that are not being internalized by them. In specific, the results of this paper show the benefit of these pricing rules regarding integration of renewables: incentivize a system with greater flexibility attributes which allows a better use of the renewable energy available, reflected in the level of renewable energy curtailment associated with each pricing scheme. Therefore, the impact on system emissions or some type of environmental metric should be a relevant policy objective to justify some additional expected costs. However, the policy challenge is clear regarding a systemic property and benefits: system flexibility and renewable integration, and the impression of additional direct energy costs. Opening the discussion about who should bear those potential additional costs: society as a whole because renewable energy brings benefits to all, demand through increased energy prices because electricity is cleaner, variable energy providers because they inject volatility into the system, or some hybrid combination. This is primary a policy question.

The other relevant policy and market design issue is how to further adapt the current markets to the needs brought by large penetration of renewable energy, given that as the results of the paper show, these new pricing schemes which capture flexibility dimensions are not enough to align private incentives with system needs. Particularly during the transition between the current energy mix and a scenario with mostly renewable energy sources, as supported by (Roques and Finon, 2017).

Central questions that need to be addressed include the timescale of the changes: short-term measures such as operational reserve demand curves (ORDCs) and improved scarcity pricing schemes (Hogan, 2019); or long-term modifications including capacity mechanisms including centralized capacity markets, strategic reserves or reliability options. Implementation challenges of ORDCs, which are usually based on several administrative, parameters are described in (Mays, 2019); a novel reinterpretation of the use of ORDCs as a practical linkage to efficient stochastic markets is described, reducing the need to rely on administrative parameters. Similarly, in (Mays et al., 2019) challenges of capacity mechanisms and its potential impacts on incentivizing low-carbon resources are described. In general, the literature shows that once risk-aversion and market power issues are taking into consideration capacity mechanisms seems to provide better outcomes than reliance only on short-term measures (Fabra, 2018; Höschle et al., 2017; Ousman Abani et al., 2018; Petitet et al., 2017). In addition, (Keppler, 2017) provides conceptual reasons regarding externalities, public good features of reliability and non-divisibility of generation investments that provide support for the need of capacity mechanisms. However, as it also pointed out in (Keppler, 2017), once the system had transitioned to a new state with more responsive demand and modular technologies, the need for such long-term capacity mechanisms might be decreased. Thus, it is an open question how fast that transition will be.

Given all these features, the solution to the investment challenges in electricity markets probably does not come only from changes to short-term energy markets or the addition of new ancillary services remunerations. Thus, the efforts in the development of market policies should be focused on generating adequate long-term market schemes to reduce or share investment risks; particularly, if features of the generation mix, for example in terms of technological attributes, are required to satisfy government objectives regarding decarbonisation (Roques and Finon, 2017; Comission, 2015). These changes could move the architecture of electricity markets towards hybrid regimes of long and short-term market structures. Long-term markets in which some requirements are centralized quantified and then market structures are deployed to satisfy that requirement, i.e., competition for the market, and short-term markets in which the resources already in place participate in energy and ancillary services competitive markets, i.e., competition in the market (Joskow, 2019b; Roques and Finon, 2017).

6. Conclusions

This paper investigates the flexibility impacts of alternative pricing schemes using tight approximations of the UC problem and short-term remuneration mechanisms. Several computational experiments show the effectiveness of the evaluated pricing rules to incentivize flexible generation, under different levels of renewable integration. An innovative aspect of the analyzed pricing rules is the use of an approximation of the convex hull pricing for the short-term payments produced by the system operation. This relaxation allows to define short-term prices that internalize flexibility features, encouraging investment decisions that are able to handle variability during the operation.

Through a comparative analysis of the marked-based mix encouraged by each pricing rule, and a comparison of the performance of each pricing rule on an optimal mix, we provide experimental evidence of the advantages of the proposed pricing rules schemes, in terms of costs and operational performance. On this way, the proposed pricing outperforms the non-linear and linear schemes in terms of market-based cost recovery, minimization of uplift payments and variable sources utilization, due to an effective spatial placement of variable and flexible resources.

Recognizing the fact that the remuneration and investment challenges in electricity markets are not only restricted to flexibility, the results of this paper provide key insights for policy regarding the need to account for flexibility requirements in markets schemes. In fact, it can be observed that although the proposed pricing rules and uplift payments schemes are adjusted as desirable in the short-term incentives, ensuring operating costs recovery for generation units, they are not enough to make flexible units profitable. Thus, it is necessary to develop additional market schemes to provide the proper incentives for flexible technologies.

Multiple paths of future work can be developed from this paper. In first place, the use of a larger system could provide important insights on the impact of the applied pricing rules when more technologies exist in the system or when physical restrictions (e.g., transmission) are considered. In terms of modeling, other pricing rules can be analyzed if a three-time period polytope is used as approximations of the convex-hull, or if min-up/min-down constraints polytopes are considered.

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