ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

INGENIERO INDUSTRIAL

INTERMITTENT RES-E, SPOT PRICES AND GENERATION INVESTMENT INCENTIVES: THE ROLE OF PRICING RULES

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Madrid
Junio 2014

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Madrid
Junio 2014

FUENTES DE ENERGÍA RENOVABLE INTERMITENTES, PRECIOS SPOT E INCENTIVOS A LA INVERSIÓN EN GENERACIÓN: EL PAPEL DE LAS REGLAS DE PRECIOS

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RESUMEN DEL PROYECTO

INTRODUCCIÓN

La reestructuración de los mercados mayoristas de electricidad se ha desarrollado de forma constante desde que comenzaran en Chile durante los años ochenta los primeros procesos liberalizadores del sector eléctrico. Aun así, la gran diversidad de parques de generación y la inevitable complejidad de su proceso de operación y planificación ha derivado en un amplio número de diseños de mercado diferentes. Un elemento común en cualquier mercado eléctrico liberalizado es el mercado diario (*day-ahead market*, DAM en las siglas inglesas). La función del DAM es casar las ofertas de generadores y consumidores para determinar tanto el precio de la electricidad como el despacho económico para cada intervalo de tiempo del día siguiente.

Existen diferentes métodos para resolver este tipo de subastas; una subasta simple o semi-compleja (subastas en la que los agentes no declaran de forma explícita sus restricciones de operación, e.g. costes de arranque o rampas) es la práctica habitual en los mercados europeos de electricidad, mientras que en los EEUU (entre otros contextos) se emplea un mecanismo de subasta compleja (i.e. cada agente generador presenta ofertas compuestas por los parámetros y costes que definen las características de su unidad de generación). En este caso el Operador Independiente del Sistema (ISO, en las siglas inglesas) recurre a un algoritmo tradicional de despacho económico centralizado (*Unit Commitment*) que calcula el despacho óptimo (Batlle, 2013).

Este proyecto se centra en el enfoque de subasta compleja. El inconveniente de las subastas complejas es que no existe una solución evidente para calcular el precio horario. De acuerdo con la teoría económica marginalista, es preferible pagar a todas las unidades de generación el mismo precio por el mismo servicio (producir electricidad) en el mismo momento (Caramanis et al., 1982) (Schweppe et al. 1988). Este precio marginal es el coste marginal del sistema (el coste variable que tendría una unidad adicional de energía en un momento dado). Este precio uniforme sirve como una señal óptima para las decisiones de corto (operación) y largo plazo (inversión). Desafortunadamente, algunas de las suposiciones sobre las que se basa la teoría marginalista no se cumplen en la realidad. De hecho, cuando los costes de arranque y de funcionamiento en vacío (también conocidos como costes no convexos) se tienen en cuenta, el precio marginal no es suficiente para compensar todos los costes (Baldick et al., 2005).

Se han ideado modificaciones *ad hoc* del sistema de precios marginales para crear una regla de precios eficiente que a la vez, proporcione remuneración suficiente para compensar todos los costes en los que incurren las unidades de generación en el despacho complejo. Actualmente se pueden encontrar dos enfoques básicos de fijación de precios y no existe consenso sobre cuál de estas reglas de precios es más adecuada. Una posibilidad, conocida como regla de precios no lineal (o discriminatoria), consiste en usar los precios marginales previamente descritos y compensar cualquier coste no recuperado a través de pagos adicionales (*side-payments*). Actualmente, este es el enfoque que aplican los ISOs de EEUU.

Por otro lado, una regla de precios lineal (o no discriminatoria) consiste en calcular un precio diferente al marginal que incluya en su formación los costes no convexos de forma que los pagos adicionales sean minimizados o completamente eliminados (Vázquez, 2003) (Gribik et al., 2007). Una de las muchas posibles reglas de precios lineales es la que se ha aplicado hasta la fecha en Irlanda.

Aunque en la literatura se puede encontrar un buen número de reflexiones sobre la idoneidad de cada regla de precios en el corto plazo, algunos de los expertos académicos más reputados en este campo han señalado que aún no se comprende bien el efecto que tienen estas reglas de precios como incentivo a largo plazo (Hogan y Ring, 2003). Además, en un contexto de gran penetración de Fuentes de Energía Renovable (RES-E por sus siglas en inglés) intermitentes, se incrementa el ciclado de las plantas térmicas convencionales. Esto aumenta la cuota de costes no convexos en los costes totales de operación lo cual puede intensificar las diferencias entre las reglas de precios (Veiga et al., 2013). La proliferación de RES-E observada en algunos sistemas eléctricos y prevista en la mayoría de ellos hace de éste un problema acuciante.

METODOLOGÍA

El objetivo de este proyecto ha sido desarrollar un modelo de simulación a largo plazo que permita analizar los incentivos a la generación producidos por cada regla de precios. Para un caso ejemplo de tamaño real, este modelo simula las decisiones de inversión de los agentes en un contexto de mercado competitivo. Para cada regla de precios el modelo da como resultado un parque de generación que refleja las señales de inversión producidas por dicha regla.

El modelo desarrollado se enfrenta a un problema no lineal de gran tamaño (gran número de variables y ecuaciones). Para resolverlo se descompone el problema en varios sub-problemas y se recurre a un algoritmo de búsqueda directa (ver Figura 1). Este diseño modular permite aplicar distintas herramientas como GAMS, Excel o Matlab según sea más conveniente. En primer lugar, el modelo genera un conjunto de posibles soluciones, cada posible solución corresponde a un conjunto diferente de decisiones de inversión (módulo 1). Para cada una de las posibles soluciones se simula, para todos los días de un año, el proceso de la subasta compleja en el DAM (módulo 2). Al despacho obtenido en el DAM se le aplican las dos reglas de precios consideradas y se determina la remuneración recibida por cada generador instalado (módulo 3). La remuneración de un generador es lo que permite establecer si una determinada decisión de inversión es adecuada. Una vez todo el conjunto de posibles soluciones ha sido evaluado se selecciona para cada regla de precios aquella solución que garantiza un equilibrio competitivo (módulo 4).

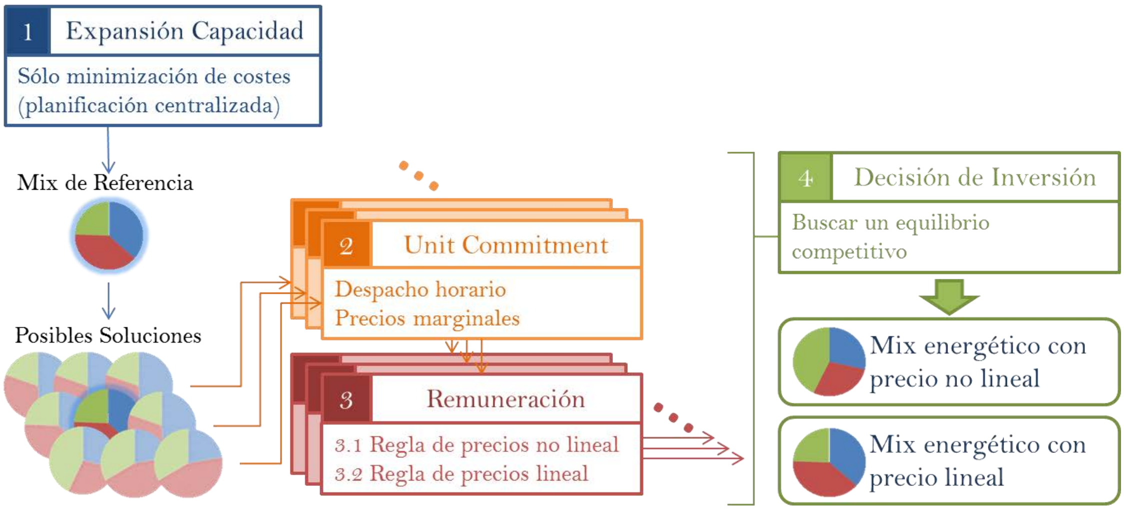

Figura 1. Diagrama resumen de la metodología

Una vez los incentivos a largo plazo producidos por cada regla de precios han sido cuantificados en términos del parque de generación obtenido, estos parques se comparan para determinar qué regla de precios es preferible en el largo plazo. Finalmente, se ejecuta el modelo bajo diferentes escenarios de penetración de renovables, estos resultados adicionales se analizan para evaluar la importancia de las RES-E en la discusión de las reglas de precios.

RESULTADOS

Inicialmente se simuló un caso base con una gran penetración de renovables obteniendo un mix energético diferente para cada regla de precios (la regla no lineal y la regla lineal). Estos mixes se comparan con un mix de referencia obtenido como el parque de generación que minimiza el coste total de operación e inversión. La regla de precios lineal produce un mix más próximo al de referencia que la regla no lineal. La regla no lineal proporciona incentivos más débiles para la inversión en generación de base (el precio no lineal no incluye los costes de las unidades de punta y por tanto la remuneración de las tecnologías de base es menor). Esto hace que se instalen más unidades de punta (centrales OCGT) de las resultantes en el caso en el que se resuelve el problema de minimización de costes, ver Figura 2.

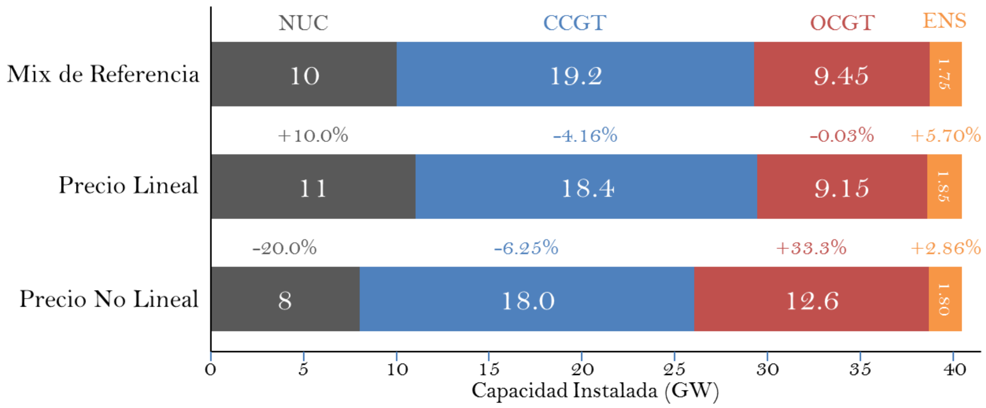

Figura 2. Resultados del mix de generación

También se compara el coste total del suministro (coste de operación y coste de inversión) asociado a cada uno de los mixes. El parque instalado bajo la regla no lineal tiene el mayor coste (Tabla i) como se esperaba por su mayor desviación del mix de referencia. Aunque la diferencia es pequeña en términos relativos, es una diferencia importante si la comparamos con el mayor coste posible que se puede evitar con un diseño adecuado del mix energético.

Tabla i. Comparación del coste total de los parques resultantes

	Coste Total Millones $	Diferencia Millones $	Diferencia Relativa %
Mix de referencia de mínimo coste	17,692		
Mix energético con precio lineal	17,693	+0.584	+0.0033
Mix energético con precio no lineal	17,816	+124.074	+0.7013

Adicionalmente, se ha aplicado la metodología desarrollada para diferentes escenarios de penetración de RES-E. Cada uno de estos escenarios toma la producción solar fotovoltaica de España en 2012 y la escala en función de la penetración a considerar (hasta nueve veces su valor para el escenario de mayor penetración renovable). Como se esperaba, la aplicación de la regla de precios no lineal resulta en un mayor valor de capacidad de generación de punta en todos los casos. Pero lo que es más importante, este efecto se acentúa con el incremento de penetración renovable (verFigura 3). El exceso de capacidad y la diferencia creciente debido a la penetración de renovables es fácilmente observable.

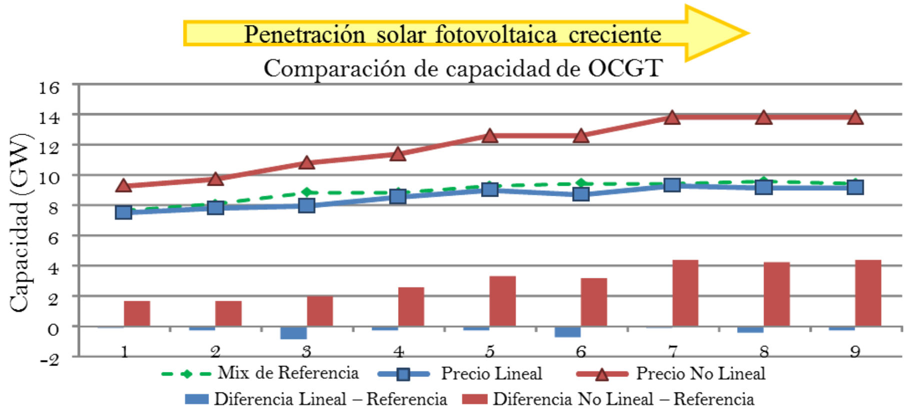

Figura 3. Evolución de la capacidad de OCGT con penetración renovable creciente

Por supuesto, esto se traduce en un incremento en el coste total del sistema. La Figura 4 muestra la diferencia en el coste total entre el mix de referencia y cada uno de los mixes basados en las reglas de precios. De nuevo, resulta evidente que la regla lineal produce un parque de generación más eficiente y que la diferencia entra las reglas de precios se agrava con el incremento de generación renovable.

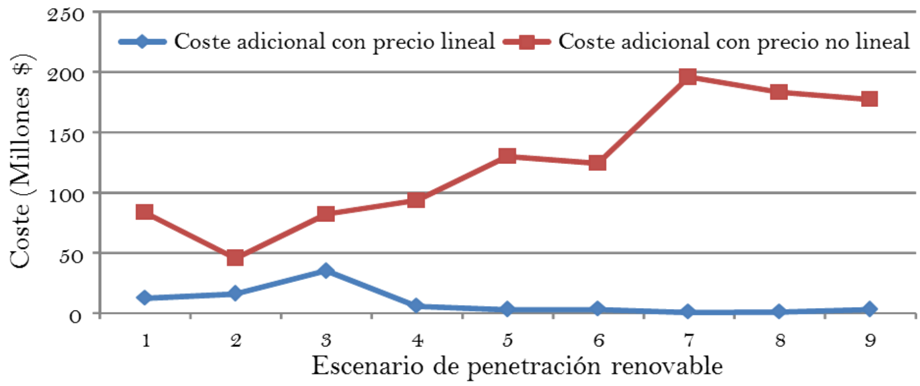

Figura 4. Desviación del coste total respecto el mix de referencia con cada regla de precios y penetración renovable

CONCLUSIONES

Este proyecto desarrolla una metodología práctica y computacionalmente eficiente para comparar el efecto a largo plazo de las reglas de precios en las señales de inversión percibidas por los agentes del mercado. Se evalúa este impacto en términos del parque de generación esperado bajo cada regla de precios.

Los resultados presentados en este proyecto sugieren que una regla de precios lineal adecuadamente diseñada puede resultar más eficiente en el largo plazo. Pero también se ha comprobado que adaptar un mercado desde una regla existente no lineal (o al contrario) puede ser un proceso problemático que requiere una cuidadosa planificación. También se ha confirmado que la introducción de fuentes de energía renovable intermitentes aumentará la importancia de la elección de la regla de precios, posiblemente requiriendo que los organismos reguladores reconsideren los diseños actuales.

La metodología desarrollada para este proyecto y los resultados obtenidos en el caso base se han reflejado en un artículo académico enviado a la revista *Energy Economics* (Herrero et al., 2014a). El análisis del impacto de los diferentes diseños de mercado para escenarios de creciente penetración de RES-E ha sido presentado en la 37ª Conferencia Internacional de la Asociación Internacional de Economía de la Energía (IAEE , por sus siglas en inglés) en Nueva York, EEUU (Herrero et al., 2014b).

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INTERMITTENT RES-E, SPOT PRICES AND GENERATION INVESTMENT INCENTIVES:
THE ROLE OF PRICING RULES

INTRODUCTION

Wholesale electricity markets restructuring has been constant since the original liberalization processes of electric power sectors started back in early eighties in Chile. Yet, the great diversity of energy mixes and the unavoidable complexities of their operation and planning have led to many different market designs. A common element in any liberalized electricity market is the day-ahead market (DAM). The purpose of the DAM is to match generators' offers and consumers' bids to determine both electricity prices and the economic dispatch for each time interval of the following day.

There are different methods to resolve DAM auctions; a simple or semi-complex auction (auctions in which the agents do not explicitly declare their operating restrictions, e.g. start-up cost or ramping constraints) is the common practice in European Power Exchanges while in the US (among other contexts) the method applied is a complex auction (i.e. each generation agent submits offers composed of the parameters and costs that define their generating units' characteristics). In this case, the ISO (independent system operator) resorts to a traditional centralised unit commitment (UC) algorithm (security constrained economic dispatch optimization) which produces an optimal dispatch (Batlle, 2013).

This project focuses on the complex auction approach. The downside of complex auctions is that finding a way to compute short-term prices has no obvious solution. According to the marginalist economic theory; it is preferable to pay all generating units the same price for the same service (producing electricity) at the same moment (Caramanis et al., 1982) (Schweppe et al. 1988). This marginal price is the marginal cost of the system (the variable cost that would have an additional unit of energy at a given moment). This uniform price serves as an optimal signal for both short-term (operation) and long-term (investment) decisions. Unfortunately, some of the assumptions in which the marginal pricing theory is based do not hold in reality. For instance, when start-up and no-load costs (aka non-convex costs) are considered, the marginal price does not suffice to compensate for all costs (Baldick et al., 2005).

Ad hoc modifications to marginal pricing have been made to create an efficient price that does provide enough remuneration to compensate all of the costs incurred by the generating units in the proposed complex dispatch. Two basic pricing approaches can be found nowadays and there is no consensus on which of these pricing rules is more adequate. One possibility, known as non-linear (or discriminatory) pricing rule, is to use the marginal price previously described and to compensate any non-recovered costs through additional side-payments. This approach is currently applied by US ISOs.

On the other hand, the linear (or non-discriminatory) pricing rule proposes to calculate a different price that includes non-convex costs in its formation such that side-payments are minimized or completely eliminated (Vázquez, 2003) (Gribik et al., 2007). One of many possible linear pricing rules has been applied in Ireland up to this point.

While many short-term considerations have been made in the literature to help determine the adequacy of each pricing rule, it has been profusely pointed out by some of the most reputed academic experts in the field that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003). Furthermore, in a context of a large penetration of intermittent RES-E (renewable energy sources for electricity), conventional thermal plants cycling is increased. This augments the share of non-convex costs in total operation costs which may intensify the differences between pricing rules (Veiga et al. 2013). The proliferation of RES-E observed in some power systems and expected in the majority of them makes this a pressing problem.

METHODOLOGY

The objective of this project was to develop a long-term simulation model to analyse the investment incentives produced by each of the pricing rules. For a real size case example, this model simulates the agents' investment decisions in a competitive market context. For each pricing rule a generation mix is obtained by the model representing the investment signals produced by each pricing approach.

The model developed faces a large (large number of variables and equations) non-linear problem. The problem is decomposed in various sub-problems so it can be solved and a direct search method is applied (see Figure 1). This modular design allows different tools to be used applied such as GAMS, Excel or Matlab depending on their convenience. In the first place, the model generates a set of possible solutions; each possible solution corresponds to a different set of investment decisions (module 1). For each of the possible solutions, the DAM complex auction process is simulated for every day in a year (module 2). Each of the pricing rules is then applied to the dispatch resulting from the DAM to determine the remuneration received by each installed generator (module 3). The remuneration of a generator determines if any particular investment decision is adequate. Once the whole set of possible solutions has been characterized, the solution that best fulfils the competitive equilibrium conditions is selected for each pricing rule (module 4).

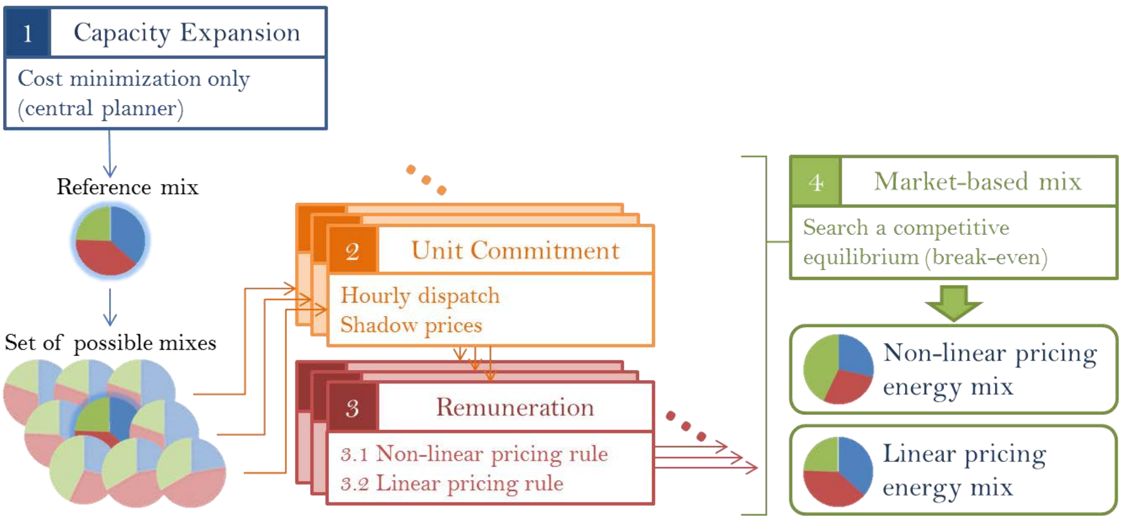

Figure 1. Methodology summary diagram

Once the long-term incentives produced by each pricing rule have been quantified in terms of the generation mix obtained, this mixes are compared to determine which pricing rule is preferable. Finally, the model will is run under different RES-E penetration scenarios, these additional results are analysed to assess the importance of RES-E in the pricing rules discussion.

RESULTS

A base case with a large penetration of RES-E was initially simulated obtaining a different energy mix for each pricing rule (non-linear pricing rule and linear pricing rule). These mixes are compared against a reference mix obtained minimizing total operation and investment costs. The linear pricing rule produces an energy mix closer to the reference than the non-linear pricing mix. The non-linear pricing rule produces weaker investment incentives for base-load generation (non-linear prices do not include all of the peaker units' costs and thus the base-load units receive less remuneration). This produces a higher than optimal amount of peak-load capacity (OCGT power plants) to be installed, see Figure 2.

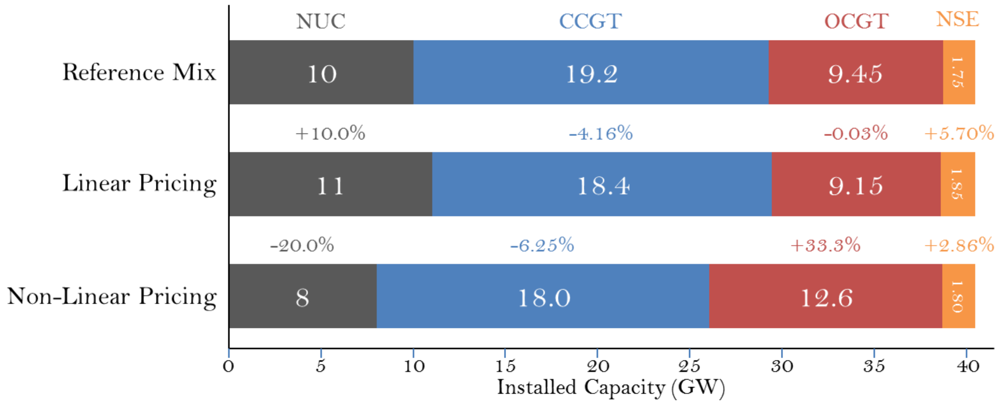

Figure 2. Generation mix results

The total supply cost (operation cost and investment cost) associated to each of these mixes is also compared. The non-linear pricing mix has the highest cost (Table i), as expected from its greater deviation from the reference mix. Although the difference is small in relative terms it is an important difference if compared to the maximum possible cost savings that a properly designed generation mix can produce.

Table i. Total cost comparison of the resulting mixes

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

Additionally, the same methodology was applied for different RES-E penetration scenarios. Each of these scenarios included the solar PV production for Spain 2012 scaled up to nine times in the scenario with the largest RES-E penetration. As expected, the non-linear pricing rule produces an excess of peak-load capacity in every case but more importantly, the problem is aggravated with the increase of RES-E penetration. The peak-load capacity (OCGT capacity) obtained in this simulation for each pricing rule with increasing solar PV penetration is represented in Figure 3. The excess of capacity and the increasing difference due to RES-E penetration are easily observable.

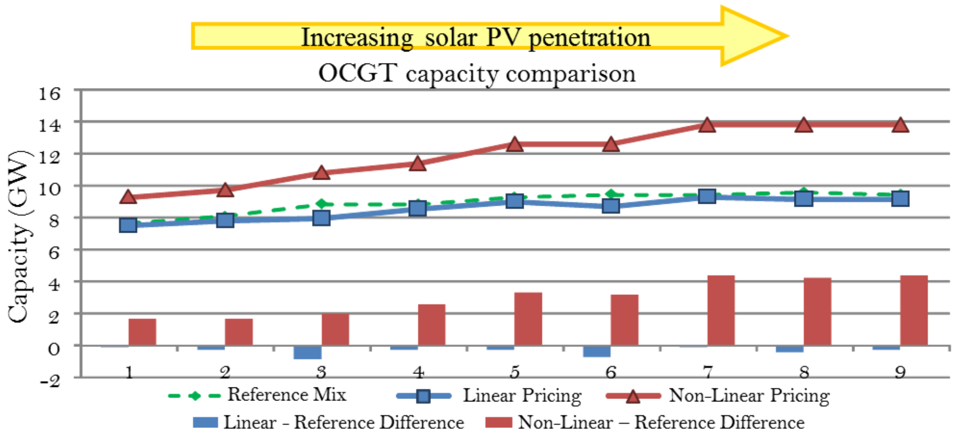

Figure 3. Evolution of OCGT capacity with increasing RES-E penetration

This of course is also translated into an increase in total system cost. Figure 4 shows the difference in total cost between the reference mix and each of the pricing rule based mixes. Again, it becomes evident that the linear pricing rule produces a more efficient energy mix and that the difference between each pricing rule is aggravated with the increase of RES-E penetration.

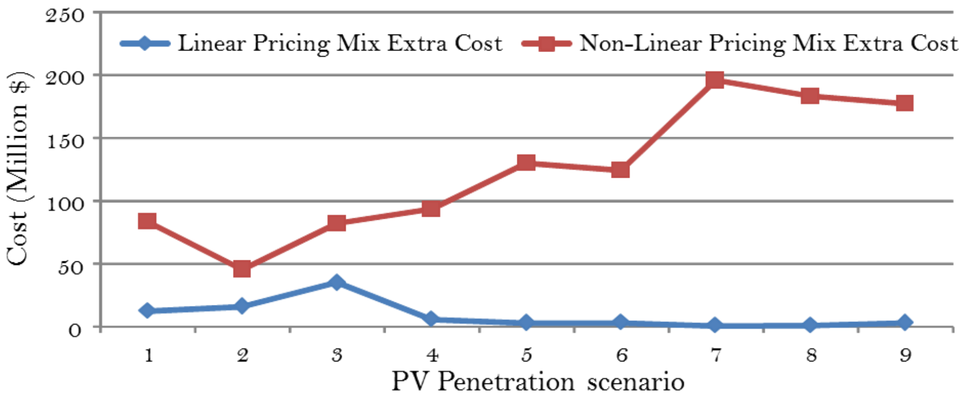

Figure 4. Total cost deviation from reference mix for each pricing rule with increasing RES-E penetration

CONCLUSIONS

This project has developed a practical and computationally efficient methodology to compare the long-term effect of pricing rules in the investment signals perceived by market agents. We asses this impact in terms of the expected energy mix to be installed under different pricing rules.º

The results presented in this project suggest that a properly designed linear pricing rule can be more efficient in the long term. But it has been evidenced that adapting a market from an existing non-linear settlement mechanism (or the other way around) could be a problematic process that requires careful planning. It has also been confirmed that the introduction of RES-E will increase the importance of the pricing rule choice possibly requiring policy makers to reconsider current designs.

The methodology developed for this project and the base case results obtained led to the submission of an academic paper to the Energy Economics Journal (Herrero et al., 2014a). The additional RES-E scenario analysis has been presented in the 37th International IAEE (International Association for Energy Economics) Conference in New York City, USA (Herrero et al., 2014b).

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CHAPTER 1. INTRODUCTION AND OBJECTIVES

1.1 Introduction and motivation

Wholesale electricity markets restructuring has been constant since the original liberalization processes of electric power sectors started back in early eighties in Chile. Yet, the unavoidable complexities of electricity generation have led to many different market designs and many associated regulatory questions (many of which remain open). In general, each design includes various markets to represent different timescales in which energy and ancillary services are traded (Batlle, 2013). This sequence of markets could be classified into long-term markets, day-ahead markets (DAM) and intraday plus balancing markets (in the EU) or real-time markets (in the US).

The core of wholesale markets is commonly the DAM, whose purpose is to match generators' offers and consumers' bids to determine electricity prices for each time interval of the following day. However, this can be achieved in a number of different ways and, as mentioned, DAMs evolved very differently in each system. An essential difference lies in the way generators can submit their offers. As explained in detail in Batlle (2013), in the majority of European Power Exchanges, market clearing is built upon simple bids (i.e. generators submit quantity-price pairs per time interval). Although some additional semi-complex conditions can be added to the bids (as for instance block bids linking bids in consecutive time intervals), this approach does not reflect either the real generation cost structure (e.g. the start-up costs) or many of the plants operation constraints (e.g. the start-up trajectory). These features can be explicitly declared in the markets run by US ISOs, where generation agents submit offers representing the parameters and costs that define their generating units' characteristics.

In principle, auctions based on simple bids have the advantage of applying a more straightforward and transparent clearing process to compute prices, but this is obtained at the expense of the efficiency of the economic dispatch[1]. In contrast, complex auctions resort to a traditional centralised unit commitment (UC) algorithm (security constrained economic dispatch optimization), with the only difference from

[1] However, while it is true that the schedule resulting from the clearing of the simple bids in the DAM is often not close to the one that in principle would result from solving a unit commitment problem with perfect information, intraday markets provide market agents with an opportunity to partly correct these potential inefficiencies.

the traditional UC problem solved in the non-liberalized context being that the data considered are market agents' bids instead of costs. The downside of complex auctions is that finding a way to compute short-term prices has no obvious solution.

In a complex auction, a uniform[2] price computed as the marginal cost of the economic dispatch solution cannot guarantee total production cost recovery for all generation agents. The marginal cost reflects the variable costs components of the offers but not the non-convex costs (start-up, no-load cost). This led to different approaches to calculate market-clearing prices that can sufficiently compensate generators for their non-convex costs; these approaches can be classified into two large groups: non-linear and linear pricing rules.

Non-linear pricing rules (also known as discriminatory) obtain a uniform marginal price (marginal cost) from the unit commitment model and, on top of it, additional side-payments are provided on a differentiated per generation unit basis. Side-payments account for the non-convex costs that the generation units could not recover solely through uniform prices[3].

On the other hand, linear pricing rules (or non-discriminatory) produce a uniform price that includes in it the effect of non-convex costs such. In the short term, the most important reason given in favour of linear pricing rules are based on efficiency implications. In particular, linear prices should bring generators' short-term offers closer to their real costs. See for example Hogan and Ring (2003) for further details.

Both of these two pricing approaches support the optimal short-term operation of DAMs but prices also have to serve as the key signal for new investments. Prices do not only compensate for operations costs, in the long run, prices resulting from a well-designed and well-functioning market should allow generators to recover the investment costs. For all inframarginal units, the difference between market prices and their operation costs should be considered a payment to finance their capital costs. Given that the uniform price perceived by all units differs from one pricing rule to the other, so does the remuneration aimed at compensating investment costs and therefore, different investment decisions should in principle be expected under each pricing rule. This long-term consideration should help to discern which of the pricing approaches is more appropriate (Vázquez, 2003). Nonetheless, it has been profusely pointed out by some of the most reputed academic experts in the field that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003), (Ring, 1995).

[2] "Uniform" indicates that all generating agents are compensated using the same price regardless of their offer.

[3] Note that side-payments resemble a "pay-as-bid" system for non-convex costs, bringing along all its inefficiency issues (Baldick et al., 2005).

1.2 Simple case illustration of different pricing approaches

The following case will illustrate the differences between non-linear and linear pricing rules. Three generation technologies are considered; base-load, mid-load and peak-load. Only variable costs and start-up costs are considered. The peak-load unit has the highest variable cost, and the base-load unit has the lowest variable cost.

In Figure 1 an hourly demand is shown; this demand is supplied by the base-load and mid-load units running for three hours at maximum power, and the peak-load unit starting-up to run for one hour. The hourly price is set by the marginal cost of the system, in this simple case the marginal price is simply the variable cost of the most expensive unit. As clearly shown in the figure, this marginal price produces profits for the base-load and the mid-load unit. The marginal price though, does not suffice to compensate for the start-up costs of the peak-load unit, which only recovers variable costs through market remuneration.

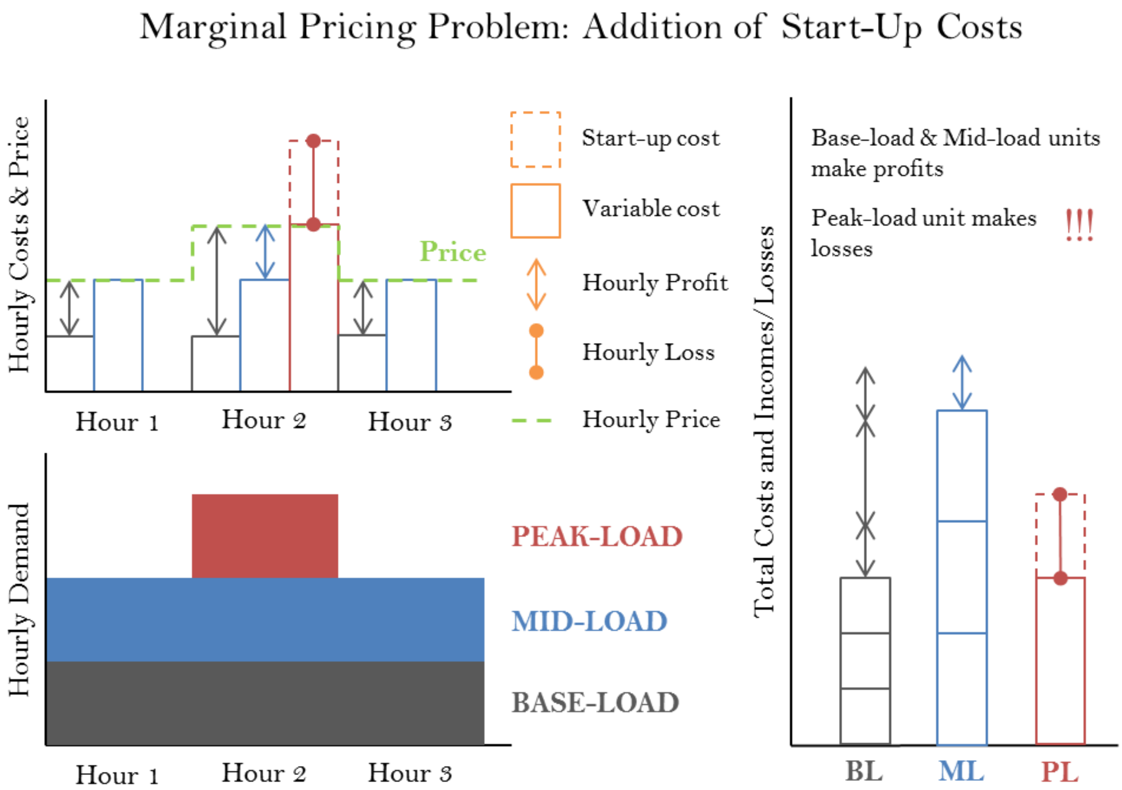

Figure 1. Simple case illustration of marginal pricing

This situation requires a different pricing approach. The previously introduced non-linear and linear pricing rules solve this problem in two different ways.

The non-linear pricing rule is illustrated in Figure 2, it relies on an additional side-payment given to the peak-load unit which compensates for the start-up cost. The base-load and the mid-load unit remain in the previous situation, making exactly the same profit as before.

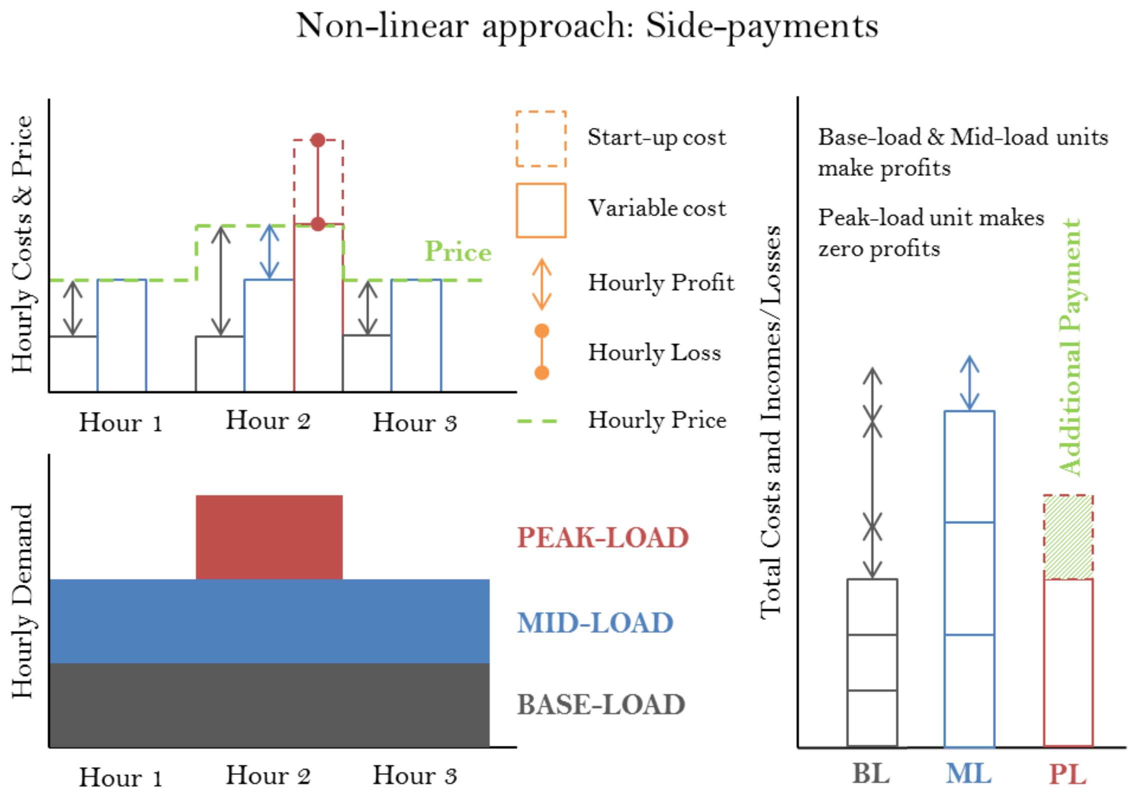

Figure 2. Simple case illustration of non-linear pricing

This approach is effectively creating two pricing regimes during hour 2. For the base-load and the mid-load unit the previous marginal price is applied. For the peak-load unit, an alternative higher price is applied. Contrary to this, the linear pricing rule relies on one uniform price only for each hour.

As shown in Figure 3, a new price has been calculated. There can be various method to calculate this new price, in any case, the new price is able to compensate for all costs without any side-payments. Just as the non-linear pricing rule, the linear pricing rule solved the problem and left the peak-load unit with zero profits. In this case though, the base-load and mid-load units now make more profits because of the new higher price.

An additional consideration to be made is that in between this two pricing rules there are infinite intermediate solutions to this problem. Note that it is possible to partly compensate the peak-load unit start-up through the market price while compensating for the rest through a side-payment.

The pricing rules just described are extreme cases of these infinite intermediate solutions. In fact, the linear pricing rule used for the simulations developed in this project lies in this intermediate area, although closer to the extreme linear pricing case.

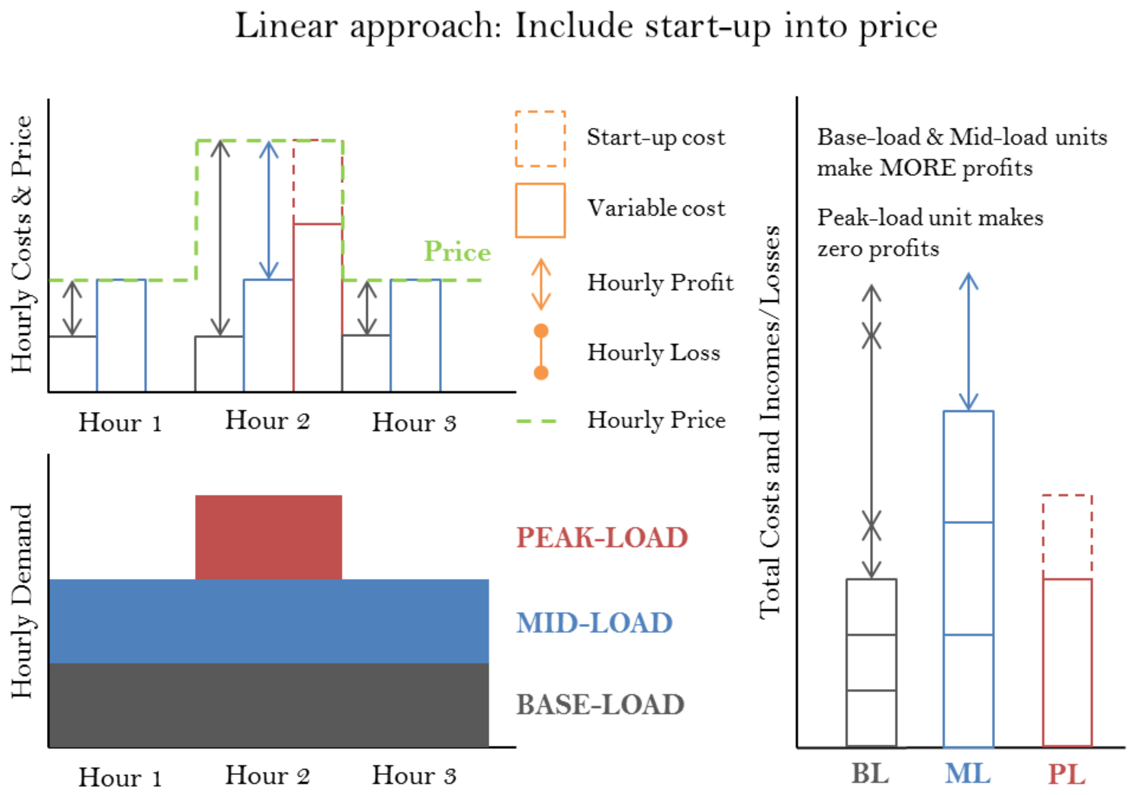

Figure 3. Simple case illustration of linear pricing

Through this simple example it has been evidenced that the different pricing rules produce different incomes for each generating technology. As exposed in the introduction, many short-term considerations have been made about these pricing rules in the literature but the long-term effect requires further research. It seems reasonable to think that investment decisions will be affected by the pricing rule implemented and we develop this idea around the objectives stated in the following Section.

1.3 Objectives

1.3.1 Assessing the long-term impact of pricing rules

The first question to be answered is whether each of the alternative pricing approaches presented (linear and non-linear) lead the market to different investment decisions. To do so, a very detailed capacity expansion optimization model will be developed.

The objective of this model will be to simulate both the short-term and the long-term behaviour of a competitive market. The result provided by this model will be the generation mix installed by market agents taking market-driven decisions under each of the pricing rules.

1.3.2 Comparing the long-term efficiency of pricing rules

We follow the evidence presented by Vázquez (2003) who compared various pricing rules and stated the following: "Although, when exclusively studying operation decisions, it seems that only variable costs need to be considered (in the price formation); when the impact of the price on investment decisions is considered it is observed that it also has to partially include non-convex operation costs. When including in the price the corresponding part of start-up and no-load cost of the marginal unit, a larger remuneration is given to inframarginal units. These inframarginal units will find a greater long-term incentive to invest, and as a consequence will partially substitute the marginal technology."

This suggests that linear pricing rules might be more efficient in the long term. If our first objective is achieved (determining the generation mix under each pricing rule), we will be able to determine which of the pricing rules led the market to a more efficient generation mix. Thus, our second objective is to quantify the long-term efficiency of each pricing rule and to extract conclusions about what market design is preferable.

1.3.3 Evaluating RES-E impact on pricing rules efficiency

Intermittent renewable energy sources (RES-E) which are expected to reach larger penetration levels in the next decades, can make this discussion more relevant. We build on the foundations of Veiga et al. (2013), who already exposed how RES-E penetration increases conventional thermal plants cycling -augmenting the share of non-convex costs (mainly start-up costs) in total operation costs- and therefore increases the differences in remuneration perceived under each of the pricing rules, especially for the case of base-load plants.

Therefore, an additional question has been raised. If (from the first two objectives) it is determined that alternative pricing rules result in the long-term in different energy mixes, we will also determine if these differences are exacerbated by a large deployment of RES-E. A scenario analysis for different RES-E penetration levels will be made to answer this last question.

CHAPTER 2. BACKGROUND

This chapter provides some useful background to help fully comprehend the discussion presented in this dissertation. First, in Section 2.1, the main and most common designs implemented in practice in organized day-ahead markets (DAMs) worldwide are classified and reviewed. Section 2.2 points out how these designs might be affected by a high penetration of VER. This analysis suggests that a strong presence of intermittent renewable generation may exacerbate the different impacts of the alternative design options.

Section 2.3 reviews the marginalist economic theory that justifies current day-ahead market pricing approaches. More importantly, it is illustrated how marginal pricing provides the right incentives for optimal long-term investment decisions under a set of ideal assumptions. The deviation from this theory when these assumptions no longer hold is precisely what is analyzed in this project.

2.1 Alternative design elements of day-ahead auctions

Electricity wholesale markets are composed of all the commercial transactions of buying and selling of energy and also other related to the supply of electricity (the so-called operating reserves), which are essential for this to occur in adequate conditions of security and quality. These transactions are organized around a sequence of successive markets where supply and demand trade the abovementioned products related to the supply of electricity in different periods.

Roughly speaking, in organized short-term electricity markets the day-ahead market (sometimes half hourly, some others even every five minutes) prices are, in principle, determined by matching generators offers and consumers bids. However, this can be achieved in a number of different ways.

Short-term electricity auctions can be classified around three major criteria:

- Whether they use complex bidding or simple bidding;
- Whether the pricing rule is discriminatory or non-discriminatory;
- Whether single, zonal or nodal prices are computed.

A number of other aspects could also be distinguished (Baíllo et al., 2006): the trading intervals used (hourly, half hourly or even every five minutes), if portfolio bidding is allowed or not (i.e. if no link is required between bids and units or on the contrary each bid must refer to a particular unit), if is there a limited number of bids for each portfolio or unit per time interval, if price caps are implemented, etc. However, next we will focus on discussing the three ones previously highlighted as most relevant plus one more, if negatives prices are allowed and to what extent.

2.1.1 Complex versus simple auction

Since electricity is a very complex commodity, and its production is subject both to inter-temporal constraints and to the existence of a number of non-convex costs, the format of the generators offers can range from the so-called simple one (a series of quantity-price pairs per time interval) to a grayscale of more complex alternatives, in which inter-temporal constraints and/or multidimensional cost structures can be declared. We build our brief review of the main alternatives around the two extremes (complex and simple auctions).

Complex auctions

In a complex auction generation agents submit offers, representing the parameters and costs which define best their generating units' characteristics (fuel cost, start-up cost, ramp up limit, etc.). With all these data, the market operator clears the market using an optimization-based algorithm which maximizes the net social benefit. This optimization algorithm shares most of the characteristics of the traditional unit commitment, but with the only difference that the data considered are market agents bids instead of costs. Usually, market prices are obtained as a by-product of the complex optimization-based algorithm.

Simple auctions

The downside of the complex-auction approach is the associated complexity of market clearing process. This factor has been the key argument held by (mainly) generators to move towards a much simpler auction, where the efficiency of the economic dispatch that results from the market clearing is sacrificed in favor of the transparency of the price computation process.

In the so-called simple auction scheme, the format of the offers does not explicitly reflect the generation cost structure (e.g. an offer component for the start-up cost) or imply any inter-temporal constraint. Instead, market agents submit simple offers/bids, which exclusively consist of price-quantity pairs representing the willingness to sell/buy the underlying product (one MWh in a certain time period of the day, e.g. an hour). Matching the market and obtaining the volume of electricity that is traded in each time period of the day is straightforward when offers and bids are simple: generation's offers are sorted in order of increasing prices and the demand's bids are sorted in order of descending prices.

Fully simple offers/bids do not imply any inter-temporal constraint. This means that for instance the offers of one thermal generating unit in the day-ahead market could be accepted in the third, fifth and seventh periods, leading to a resulting unit schedule which could be highly uneconomical or simply infeasible from the technical perspective. As we later further discuss, the main drawback of this approach is that it entails that to some extent generators have to anticipate (based on conjectures) the dispatch so as they properly internalize all cost in the hourly price component.

Hybrid or semi-complex auctions

In principle, the previous inconvenience could be partially fixed either by means of subsequent secondary trading (in the so-called intraday markets, in the EU context, or in the real-time market, e.g. in the US, see below) or closer to real time later in the balancing mechanisms/markets managed in most cases by the System Operator. However, in an attempt to combine the advantages of the complex and the simple auction design, EU PXs have opted for implementing hybrid alternatives, allowing linking semi-complex conditions to their offers.

The common idea behind the design of these semi-complex designs is simply to introduce as few complex constraints as possible in the auction, so as to not to complicate the matching process in excess while at the same time removing the huge risk at which agents are exposed in the simple auction context. Obviously, there is a whole continuum, between the extreme of including all potential constraints and the extreme of including none of them. The larger the number of constraints allowed, the closer the offers can represent the cost functions of the generating units.

In practice, this trade-off has been achieved either by introducing some of the most relevant (most difficult to be internalized) constraints, as it is the case with the ramp-up constraint (used in the Iberian day-ahead market) or by allowing some heuristic-based inter-temporal constraints in the offers format, in most cases not necessarily representing actual constraints or cost components, but rather a mixed effect of many of them.

Some of the complex conditions and offers used in semi-complex auctions are for example user-defined block bids (implemented, among others in the Nordpool, EPEX Germany and EPEX France), meaning that a market agent can offer/bid a price/quantity pair for a set of consecutive hours (three as a minimum), flexible hourly bids (Nordpool & EPEX France), i.e. price/quantity pairs with no pre-defined hourly period assignment or the so-called minimum income condition implemented in OMIE, enabling a generating unit to include a minimum income condition expressed as a fix (expressed in euros) and variable term (in euros per MWh) associated to the whole set of hourly bids corresponding to one particular unit.

2.1.2 Pricing rules: discriminatory versus non-discriminatory payments

The computation of market prices as well as the related determination of the generating units' remuneration is a quite controversial and still open issue in the context of complex auctions. We can classify these approaches in two large groups:

- non-linear pricing rules (also known as discriminatory pricing schemes), according to which, on top of the hourly prices, some additional side-payments are provided on a differentiated per unit basis;
- linear (or non-discriminatory) pricing rules, according to which the same hourly price is used to remunerate all the hourly production and no side-payments exist.

As it can be straightforwardly observed, the key factor that differentiates these two rules is that they yield different payments for consumers and correspondingly different income for generating units.

Non-linear pricing

In the context of complex auctions, non-linear (or discriminatory) pricing is undoubtedly the most extended pricing rule (especially in the US markets). This mechanism translates into each generator having a remuneration consisting of:

- first, a set of (non-discriminatory) prices which serve to remunerate all production in each time period,
- and then, some additional discriminatory side-payments (in practice computed as a lump-sum daily payment) which are calculated on a per unit basis.

As a consequence of the method used to compute marginal prices, these prices do not include the effect of non-convex costs (as it is the case with start-up or no-load costs). This is the reason why additional payments are considered on a per unit basis so as to ensure (if necessary) that every unit fully recovers its operating costs.

Linear pricing

Although the non-linear pricing approach is the most extended alternative in the context of complex auctions, linear pricing is also a possibility. Linear pricing in this type of auctions entails computing non-discriminatory hourly prices in such a way that all generating units fully recover their operation costs (thus avoiding the need for discriminatory side-payments of any kind), so in each time period (e.g. hour) every MWh produced is remunerated with the same hourly price.

Finally it is important to remark that we have just focused on the complex auction context. The reason is that the linear versus the non-linear pricing discussion has been less relevant in the context of simple auction. This is mainly because the question on whether or not the single price should internalize the effect of non-convex costs (such as the start-up cost or the no-load cost) makes no sense in the simple auction scheme. In the simple auction context generators have to internalize all types of costs in their price-quantity pairs offers. Once submitted, there is no way for the market operator to make distinction on which part of the price corresponds to convex and which part of the price corresponds to non-convex costs.

2.2 Auction and pricing design for high shares of RES-E

Under normal circumstances, the particular design of the short-term market (format of the bids, market clearing algorithm and pricing and remuneration rule) conditions the market results. As discussed by Rodilla & Batlle (2012), a significant penetration of VER may exacerbate the outcomes of the different design elements just introduced. Next the arguments of these authors are developed.

2.2.1 *Efficiency of the economic dispatch resulting from simple and complex auctions in the presence of VER*

In the simple auction scheme, agents have to calculate the quantity-price pairs in such a way that all expected costs (including non-convex costs, such as the ones related to starts) are properly internalized. This way, for instance, a peaking unit expecting to have to start to produce electricity the next day in four hours (e.g. for the evening peak, from 6 p.m. to 10 p.m.) and then shut down, would have to impute all operation-related costs in those hours. Note that, since generators do not know in advance the resulting dispatch (e.g. the hours in which the unit will be finally committed), it is evident that this internalization is subject to risk (e.g. the market clearing results might imply that unit should be committed just two hours), and thus, may lead to inefficiencies in the resulting dispatch (the income in these two hours might not be enough for the unit to fully recover its operating costs).

On the contrary, complex auctions enable generators to better align their offers with their actual generating units' cost structure. This scheme allows agents to better express their willingness to buy and sell electricity, since it allows them to declare all parameters defining generation technical constraints (e.g. ramp-up and down limits, etc.) and generation costs (heat rate efficiency rate, hot start cost, cold start cost, wear-and-tear-derived costs, etc.). By providing all these detailed data, the generating unit is most likely scheduled in the most efficient way. In this context, the generator does not need to anticipate ex-ante which the resulting dispatch will be, since this intricate issue can be left in the hands of the optimization algorithm.

As previously stated, in the case of the day-ahead markets of EU Power Exchanges, in which simple bids were originally considered, this problem has been tackled in two sequential (ex-ante and ex-post) and complementary ways: semi-complex conditions aim at reducing the risk of market agents associated to the simple bid decision-making process, and secondary markets provide market agents with additional opportunities to reschedule their positions[4]. Thus, these two tools can be used to first avoid and then

[4] Intraday sessions as for instance the ones implemented in the Iberian or French cases or balancing markets as the ones also implemented in France or Elbas in Nordpool.

(if necessary) correct a non-profitable scheduling that has previously resulted in the day-ahead market.

Nevertheless, in practice these two alternatives are still far from solving the efficiency loss problem linked to simple bidding. First, secondary markets in theory would allow market agents to first solve the potential infeasibilities that might result from the day-ahead market clearing, and at the same time to gradually adjust their schedules to changing conditions. But on the one hand, transaction costs, although not significant, cannot be considered as negligible: being able to properly trade in these markets implies additional costs for market agents. And more importantly, due to the traditionally oligopolistic structure of a good number of electricity markets, these secondary markets have proven not to be always liquid enough, increasing the costs for particularly generators owning small generation portfolios, and thus affecting to their competitiveness[5].

Second, semi-complex conditions certainly are a valuable tool for market agents to mitigate their risk to face an uneconomical (or even technically infeasible) schedule resulting from the market clearing. But by no means they guarantee that efficiency of the schedule resulting from the market clearing is maximized. Most of the simple bids linked to semi-complex conditions explicitly or implicitly expose generators to the necessity of anticipating under uncertainty their expected dispatch. This is for instance evident in the case of block bidding, where generators have to decide the hourly interval in which they are willing to offer their energy (e.g. from 10 a.m. to 15 a.m.). Then, on the basis of this expected dispatch, it is possible to add a "kill-the-offer" condition if a minimum income is not perceived. In the example of the block bid, this is expressed usually through an average price.

Simple and semi-complex-conditioned offers allow for a significantly less flexibility than the complex bidding alternative. Note that the kill-the-offer condition allows avoiding the risk of losses for the generating agent, but does not avoid the risk of not being scheduled in the most efficient way from the standpoint of the overall system economic dispatch optimization[6]. For instance, an offer killed by the semi-complex condition may have been scheduled in some other intervals in such a way that both the system and the agent would have been better off.

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[5] See for instance Batlle et al. (2007). Although the situation apparently has improved after the implementation of intraday markets, observed balancing spreads have occasionally been rather significant.

[6] Ideally (in a competitive market) this solution is also supposed to represent the equilibrium, i.e. the desired schedule from the agent's point of view in the absence of market power.

2.2.2 VER and the efficiency of the auction design

A large penetration of VER directly increases the need for flexibility and thus for balancing resources. This has been the case in those markets in which the deployment of VER has been particularly significant, as for instance the German or Spanish cases, to name two particularly relevant examples. But, at least for the moment, since storage technologies and demand response tools are not yet sufficiently developed, this increasing need has not been accompanied by an equivalent addition of flexible technologies able to cope with it with the same level of efficiency. Thus liquidity is lower, and therefore the cost of adjusting the generation programs resulting for the market clearing are larger.

In the case of complex auctions, the presence of wind does not impact in a relevant way the generators strategies. Obviously, the associated uncertainty will introduce a risk component in the determination of the net social benefit, but this should not affect to generators' offers, since again, the algorithm is the responsible of finding the optimal schedule.

In the case of simple auctions, ideally, under perfect information, the offers of all the market agents would also lead to the most efficient economic dispatch, the one corresponding to the equilibrium under perfect competition conditions. But in this case, a significant amount of wind in the system entails an additional source of uncertainty on the expected day-ahead market scenarios on which the bids building process of each market agent is based. The consequence is therefore that the disparity of these market agents' estimations grows, and thus the errors are more likely and the market result further deviates from the optimum.

As argued by Vázquez et al. (2014), there is empirical evidence about the fact that VER significantly complicates the bidding task of market agents in simple and semi-complex day-ahead markets: bidders make an increasing use of semi-complex constraints as the amount of installed VER grows, as well as also these constraints activate the kill-the-offer condition accordingly. This kill-the-offer condition can allow some generators hedging from an incorrect assessment of the future market conditions when building the bids, but it will obviously will be too restrictive for some others whose production could probably have been scheduled in a different pattern than the one implicitly included in the semi-complex offer. When the amount of offers killed by the algorithm becomes large, the efficiency of the market results can be put into question.

Take for instance the case of the Spanish system, where the deployment of wind and solar technologies has been more than remarkable[7]. Since the start of the market in Spain back in 1998, market agents operating in OMIE, the Iberian day-ahead market, can link their hourly quantity-price pairs to semi-complex constraints. The market clearing algorithm then searches for a solution that respects the constraints, so result is that a number of bids are killed. This is clearly illustrated in the figure below, in which for a particular hour back in 2010, the market matching, including the supply function before considering the quantity-price simple offers and the finally considered offer curve, resulting from the activation of the semi-complex conditions (in thick trace) are shown.

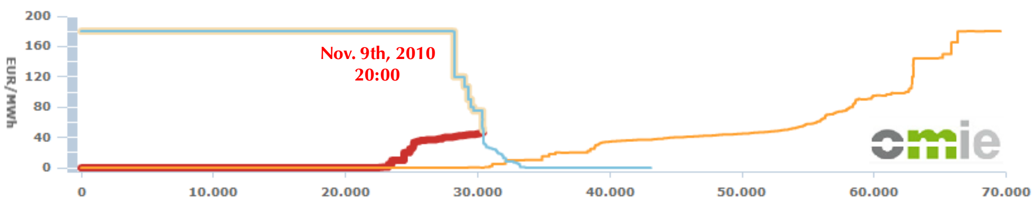

Figure 4 Renewable Market price settlement in OMIE

The effect that VER have had on the relevance of these semi-complex conditions is clearly illustrated in the figure below, taken from Vázquez et al. (2014). The withdrawn energy in the day-ahead market stemming from the activation of the minimum income condition in the peak hours is depicted along with the evolution of daily wind production from 2002 to 2010.

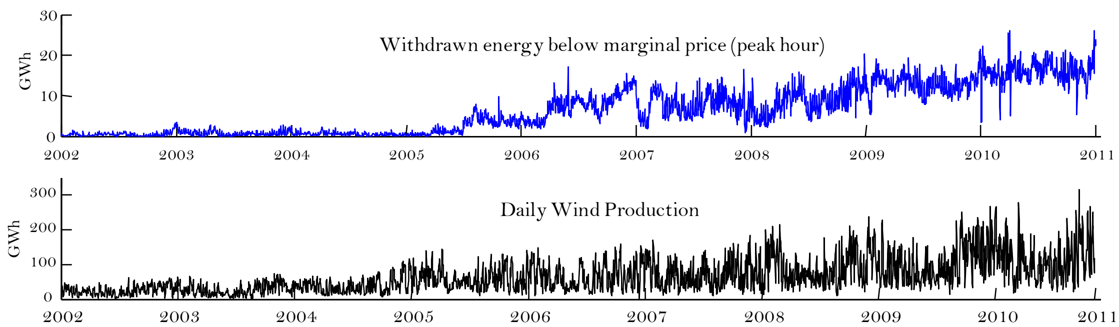

Figure 5 Energy withdrawn as a consequence of the activation of the complex conditions

As the installed capacity of VER (namely wind, but also a significant amount of solar PV, around 4 GW as for the end of 2010) has grown, the amount of energy discarded

[7] As of the beginning of 2012, the installed capacity of wind was close to 21 GW, plus 4 GW of solar PV and 1.2 GW of solar thermal, while the recorded peak demand in 2011 was 44 GW.

in the final market clearing due to the activation of semi-complex constraints has increased accordingly[8].

In the same line, Borggrefe & Neuhoff (2011) argue market design needs to allow generators to adjust their energy production and provision of balancing services in a joint bid, so that they can contribute to an efficient system operation.

2.2.3 Non-discriminatory versus discriminatory pricing in a context with high penetration of VER

Veiga et al. (2012) shows how the pricing rules implemented (either uniform prices or the shadow prices resulting from the unit commitment plus additional side-payments) may amplify or reduce the resulting change on short term price dynamics due to the presence of VER. To do so, the authors base their discussion on a simulation analysis using a detailed unit commitment model, able to capture the impact of cycling in the short-term price formation.

The two pricing contexts selected are respectively a simplified version of the pricing rules in force in the US ISOs short-term markets (as e.g. PJM or ISO-NE) and a simplified version of the pricing rules in force in the SEMO short-term market in Ireland. While in the first ones a uniform price not including non-convex cost is used in addition to some discriminatory side-payments to ensure operation cost recovery, in the latter just uniform prices including the effect of the non-convex costs serve to remunerate all generation.

The authors show how in the particular context of a system with large penetration of VER, non-convex costs are expected to increase and argue that, due to the increased impact of the non-convex costs of conventional thermal plants, the growing deployment of VER exacerbates these differences, which can have a relevant effect on the long-term capacity expansion of the system. It can be observed that the income in the linear pricing context increases when a significant amount of solar is added into the system due to the increase of the costs related to the larger need to start the plants and therefore to increase the O&M costs.

The authors illustrate how the income for a baseload plant is significantly different depending on the pricing rule implemented, what naturally would lead to a different generation mix in the future. The income in the discriminatory context is equal

---

[8] It is important to note that this increase cannot be attributed to a demand growth, since in the Spanish case electric power demand has experienced a very significant decrease from 2008 (281 TWh) to 2011 (261 TWh), a drop of around 7.5% in three years.

without and with a large penetration of VER as the calculated prices do not include the non-convex costs such as no-load or start-up costs of the marginal units and the marginal generator is a ccgt plant in both scenarios. Conversely, in the linear scheme, these start-up costs are perceived by all units.

One question raised by Veiga et al. (2012) is about the role of short-term market prices as optimal long-term signals. If short-term prices have to serve as incentives to bring in the most efficient investments (from the net social benefit standpoint), prices need to reflect what the energy is worth, and this necessarily calls for internalizing all related-costs in the market price. Thus, linear pricing rules (which internalize the non-convex-cost-related component of the actual value of electricity) may be the best option to send proper sound long-term market signals.

2.3 Optimal short-term prices under ideal hypotheses[9]

2.3.1 Theoretical results under ideal hypotheses

Here we review the major results stemming from microeconomic marginal theory applied to electricity markets, and we show how short-term prices, under ideal hypotheses, are supposed to drive efficient operation, planning and investments.

The application of microeconomic marginal theory to the electric power systems was first sketched by a MIT research group (Caramanis et al., 1982), (Bohn et al., 1984), (Caramanis, 1982), (Schweppe et al. 1988) and has been subsequently complemented and refined by some other works, among others (Pérez-Arriaga, 1994), (Pérez-Arriaga & Meseguer, 97), (Baughman et al, 1997) and (Vázquez, 2003).

The classic analysis makes use of a reference model, which consists in an ideal centralized planner having perfect information about costs and agents' preferences, and whose objective is the maximization of the net social benefit. This reference model is compared with the one resulting from a market context where short-term energy prices are the sole signal driving agents' decisions. The main objective is to analyze whether or not both contexts are equivalent, in other words, whether or not short-term market prices are capable of driving efficient operation, planning and investments.

Some ideal hypotheses are considered in this analysis, being the most relevant ones:

- Generators' costs functions are convex.
- Agents' are not risk averse.
- Generators can only get revenue from the sale of their energy in the short term market.
- There are neither economies of scale nor lumpy investments.
- The market is perfectly competitive.

Optimal prices for operation

The optimal centralized operation problem consists in a central planner maximizing the net social benefit. Thus, this problem can be schematically represented as:

$$
\begin{aligned}
&\underset{q_{ih}}{Max} \quad \sum_h [U_{dh}(\sum_i q_{ih}) - \sum_i C_i(q_{ih})] \\
&s.t. \\
&\qquad q_{ih} \le \overline{q}_{ih} \quad \perp \psi_{ih} \\
&\qquad R(q_{ih}) = 0 \quad \perp \zeta_{ih}
\end{aligned}
\tag{1}
$$

[9] This Section heavily relies on Rodilla (2010).

Where:

$C_i(q_{ih})$ represents the variable costs incurred by the unit i when producing the quantity q_{ih} in the hour h

U_{dh} represents the demand utility function in hour h for the total consumption $Q_h = \sum_i q_{ih}$.

$\overline{q}_{ih}$ is the maximum output limit of unit i in hour h.

$R(q_{ih}) = 0$, represents schematically the operational technical constraints of the different generating units.

ψ and ζ are the dual variables of the previous constraints.

By forming the Lagrangian function and then calculating the first order derivative with respect to the decision variables (q_{ih}) we obtain the optimality conditions of the problem:

$$\begin{aligned} &\frac{dU_{dh}(\sum_i q_{ih})}{dq_{ih}} - \frac{dC_i(q_{ih})}{dq_{ih}} + \psi_{ih} + \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih} = 0 \Rightarrow \\ &\Rightarrow \frac{dU_{dh}(Q_h)}{dQ_h} = \frac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih}, \forall i,h \end{aligned} \tag{2}$$

Therefore, each generating unit should produce in each hour up to the level in which its marginal costs equals the marginal demand utility, in other words, the cost of producing an additional unit ($/MWh) should equal the price ($/MWh) that the demand is willing to pay for the last MWh consumed. Indeed, this relationship will only be true in each hour h for the marginal unit, which is the generating unit i that is producing in that moment and whose technical constraints are not binding (i.e. ψ_{ih} and ζ_{ih} have a zero value).

On the other hand the problems of the generators and demand in a market context can be represented as:

$$\begin{array}{ll} \textit{Demand's problem} & \textit{Generators' problem} \\ \underset{Q_h}{Max} \sum_h [U_{dh}(Q_h) - \pi_h \cdot Q_h] & \underset{q_{ih}}{Max} \sum_h [\pi_h \cdot \sum_i q_{ih} - \sum_i C_i(q_{ih})] \\ & s.t. \\ & q_{ih} \le \overline{q}_{ih} \quad \perp \psi_{ih} \\ & R(q_{ih}) = 0 \quad \perp \zeta_{ih} \end{array} \tag{3}$$

Again, we obtain the first order condition for each one of the corresponding Lagrangian functions with respect to the decision variables (Q and q_{ih} respectively) so as to analyze the optimality conditions of each problem:

$$\begin{array}{ll} \textit{Demand's optimality conditions} & \textit{Generators' optimality conditions} \\ \dfrac{dU_{dh}(Q_h)}{dQ_h} = \pi_h, \forall h & \pi_h = \dfrac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \dfrac{dR(q_{ih})}{dq_{ih}} \zeta_{ih}, \forall i, h \end{array} \tag{4}$$

It is straightforward to check how these optimality conditions are equivalent to the conditions obtained in the central planner problem[10]. Therefore, under the ideal hypotheses enumerated above, both contexts should provide the same outcome.

Note that short-term prices should always be determined by the marginal demand utility. These short-term prices are also equal to the marginal costs of the marginal unit. But in the particular case where all existing plants are at their full capacity, the market price will not correspond to any of their marginal costs. This is a very important: when there is not enough generation to meet demand requirements, the price has to be set by the demand (not by any of the marginal costs of the generating plants) so as to ensure an efficient outcome.

Optimal prices for investment

We have seen how short-term prices should drive an efficient operation in a market context. But, in order to conclude that both, the ideal central planner and the market context, lead to the same results, it is essential to prove that short-term market prices send also optimal signals to long-term investments. With this purpose we next extend the previous analysis in order to include the investments in generation.

The new optimal centralized operation and investment problem can be schematically represented as:

$$\begin{array}{l} \underset{\overline{q}_{ih}}{Max} \quad NSB(q_{ih}, \overline{q}_{ih}) - \sum_i IC_i(\overline{q}_{ih}) \\ NSB = \begin{cases} \underset{q_{ih}}{Max} \quad \sum_h [U_{dh}(\sum_i q_{ih}) - \sum_i C_i(q_{ih})] \\ s.t. \\ \qquad q_{ih} \le \overline{q}_{ih} \qquad \perp \psi_{ih}, \ \forall i, h \\ \qquad R(q_{ih}) = 0 \qquad \perp \zeta_{ih}, \ \forall i, h \end{cases} \end{array} \tag{5}$$

Where:

NSB is the net social benefit, i.e. the objective function of the centralized scheduling problem.

[10] Note that for the sake of simplicity we have assumed that the set of R constraints is the same in both cases (central planner and market). In this respect, a more general representation can be found in (Pérez-Arriaga, 1994).

IC_i represents the investment costs of the generating plant i.

The optimality condition of the investment problem is:

$$\frac{dNSB}{d\overline{q}_{ih}} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}} \tag{6}$$

Meaning that investments should be carried out up to the point in which the long-term marginal cost equals the short-term marginal increment of the net social benefit.

In the operation problem, if we take into account the relation existing between the objective function and the dual variable ψ_{ih} we have:

$$\frac{dNSB}{d\overline{q}_{ih}} = \psi_{ih} \Rightarrow \psi_{ih} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}} \tag{7}$$

Thus, if we introduce the previous expression in the first order condition of the operation problem we obtain:

$$\frac{dU_{dh}(Q_h)}{dQ_h} - \frac{dC_i(q_{ih})}{dq_{ih}} + \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih} = -\frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}, \forall i,h \tag{8}$$

On the other hand the generators' and demand problem in a market context can be represented as:

$$\begin{array}{ll}
\text{Demand's problem} & \text{Generators' problem} \\
\underset{Q_h}{Max} \ \sum_h [U_{dh}(Q_h) - \pi_h \cdot Q_h] & \underset{\overline{q}_{ih}}{Max} \ B - \sum_i IC_i(\overline{q}_{ih}) \\
 & B = \begin{cases} \underset{q_{ih}}{Max} \ \sum_h [\pi_h \cdot \sum_i q_{ih} - \sum_i C_i(q_{ih})] \\ s.t. \\ \quad q_{ih} \le \overline{q}_{ih} \qquad \perp \psi_{ih}, \ \forall i,h \\ \quad R(q_{ih}) = 0 \quad \perp \zeta_{ih}, \ \forall i,h \end{cases}
\end{array} \tag{9}$$

Where

B is the generator accumulated benefit (along the period considered) in the short-term market, i.e. the objective function of the generator' s operation dispatch problem in a market context.

The optimality conditions of this problem are:

$$\begin{array}{ll}
\text{Demand's optimality conditions} & \text{Generators' optimality conditions} \\
\frac{dU_{dh}(Q_h)}{dQ_h} = \pi_h, \forall h & \frac{dB}{d\overline{q}_{ih}} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}} \Rightarrow \psi_{ih} = \frac{dIC_i(\overline{q}_{ih})}{d\overline{q}_{ih}}, \forall i,h \\
 & \pi_h = \frac{dC_i(q_{ih})}{dq_{ih}} - \psi_{ih} - \frac{dR(q_{ih})}{dq_{ih}}\zeta_{ih}, \forall i,h
\end{array} \tag{10}$$

Again, it is straightforward to check how these optimality conditions are equivalent to the conditions obtained in the central planner problem. Therefore, under the ideal hypotheses enumerated above, both contexts should provide the same outcome in terms of operation and investments.

2.3.2 Inframarginal profits: illustrating how fixed investment costs are recovered in the market context

Next we use a simplified example to further illustrate how market prices ensure the recovery of both operational and investment costs. Two additional ideal assumptions with respect to the former analysis have been introduced for the sake of simplicity in the exposition: no technical constraints are considered in the operation and the marginal demand utility has been considered to be constant.

To show, in a simplified way, how generators can fully recover their investment costs from the income derived from the energy market (although prices are based solely on operating short-term costs and demand's short-term marginal utility), the graphic procedure (also known as the screening curves method) that was used in traditional systems to calculate the optimal generation mix that minimizes overall costs can be used.

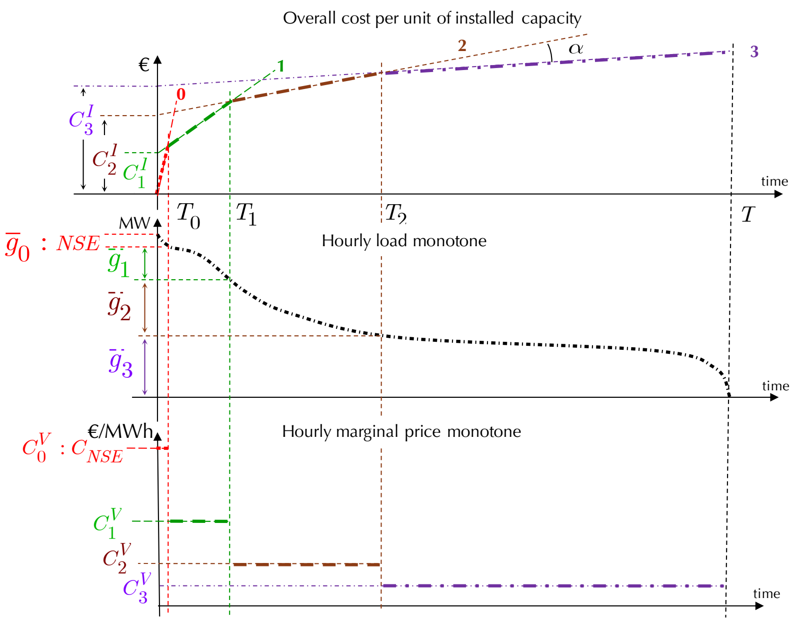

Figure 6. Optimal generation mix

The upper part of Figure 6 (below) represents the evolution (per unit of installed capacity) of different technologies' overall costs as a function of the number of hours of use. Technology 0 has no investment costs, so there is no cost if it is not used, and it has a high operating cost, so the costs increase rapidly with the hours of use. This "technology" is a means of representing the social cost which derives from the loss of demand surplus when some energy cannot be provided by other existing technologies.

This is a key issue for the success of the overall design, since it is essential to ensure the recovery of the investment costs of the generating units. This is particularly so in the case of the peaking units (traditionally the ones that have the highest variable costs; technology 1 in the case of the example) where, if they are not paid their opportunity cost, which should be related to the cost of the non-served energy (the technology 0 in the case of the example), no investment cost will be recovered at all.

Technologies 1, 2 and 3 do have some fixed investment costs, denoted in the figure as C_1^I, C_2^I and C_3^I respectively, which constitute respectively the total cost when the equipment is not used. From this value, costs grow in proportion to each technology variable's cost of operation.

The piecewise-linear bold line at the top of Figure 6 shows the most efficient alternative for each value of hours of use. Thus, if a certain megawatt of generation is going to be used for a number of hours greater than T_2, then the best solution is to construct a megawatt of technology 3. If that megawatt is to be used for a period that falls between T_2 and T_1, the most efficient alternative would be to construct a megawatt of technology 2 (and analogously for T_1 and T_0 and technology 1). Finally, if the group is going to be producing fewer hours than T_0, then it is better to provide that consumption with a megawatt of the type 0 "generator", i. e. it is not worth supplying that energy.

Once the T_2, T_1 and T_0 values are known, by means of the graphical analysis shown in the figure, it is possible to determine, using the system load monotone (also known as the load duration curve), how much power will be consumed for more than T_2 hours, how much will be consumed between T_2 and T_1 hours, and so forth. Thus, the $\overline{g}_1$, $\overline{g}_2$ and $\overline{g}_3$ capacities that must be installed in each of the three production technologies considered can be obtained. This process is illustrated in the second graph in Figure 6, which represents the optimal capacities that ensure overall cost minimization; hence this process also represents the desirable mix under a centralized hypothesis.

From now on, we will assume that this is the generating mix installed in a competitive market and we will assess whether short term market prices allow a full recovery of investments costs.

In the time interval between T_2 to T, technology 3 sets the system's marginal price, which equals its variable cost C_3^V (see the lower graph in Figure 6). That price allows technology 3 generators to recover their costs of operation, but does not provide any compensation for their investment costs. In the interval that ranges from T_1 to T_2 the market price equals the variable cost of the technology 2, C_2^V . Technology 3 obtains, in each of those hours, an operating profit that equals the difference between technology 2's variable cost and its own variable cost. Graphically, this is equal to the difference between the slope of the costs curve, in other words, the tangent of the angle. Thus, group 3 obtains a profit equal to the price spread for the duration of the period, i. e. $\text{tg}\alpha \cdot T_2 - T_1$. In Figure 7, this is equal to the segment a .

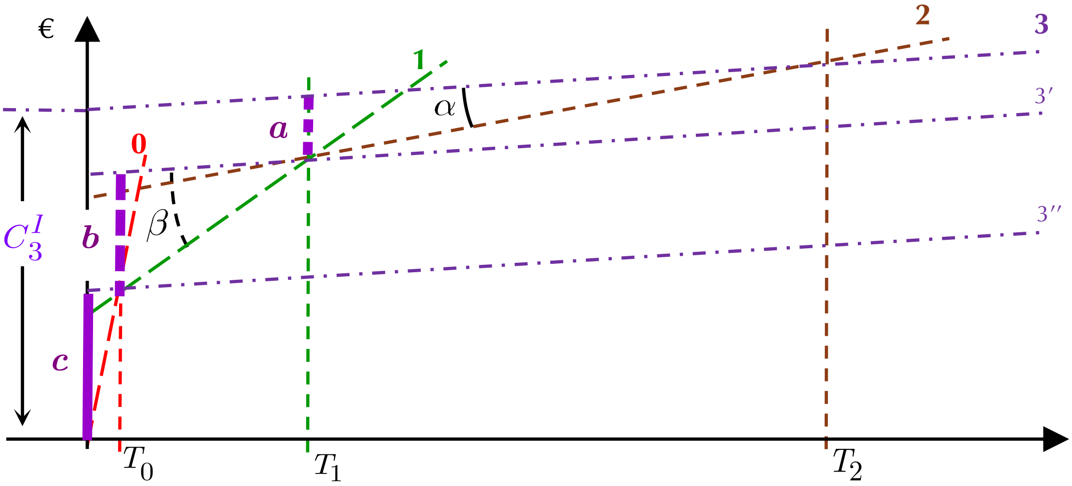

Figure 7. Detail of Figure 6: technology 3's investment cost recovery.

Similarly, in the hours that go from T_1 and T_0, technology 3's income will be equal to $\text{tg}\beta \cdot (T_1 - T_0)$, which is the segment b , and analogously the segment c , for the interval from zero to T_0. As can be seen, the sum of the segments a , b and c (total income) is equal to technology 3's investment cost (C_3^I).

It is important to note the importance of the segment c , which represents the income received when the generation is scarce and, as previously mentioned, the price is set by the demand. If restrictions are imposed on the price during those hours, neither the peak generator nor all the remaining technologies will be able to fully recover investment costs..

The procedure can be repeated analogously for technologies 2 and 1, with equivalent results. This reasoning, which has been presented here with only three (plus one) generators for the sake of simplicity, can be extended without any difficulty to a larger number of energy generation technologies.

Thus the generating mix that minimizes overall costs provides the scenario in which all generation fully recovers both its investment costs[11] and its operation costs. This is

[11] Including depreciation and a rate of return on debt and equity capital

known as the generators' break-even position. If less generation than the optimal amount is installed, then the market provides higher profits for existing generation. These additional profits act as a signal to attract more generation up to the optimal generation mix, where the break-even position is restored. On the contrary an excessive reserve margin would lead the market to penalize poorest investment decisions.

CHAPTER 3. MATERIALS AND METHODS

3.1 Overview

The approach developed in this project aims at calculating the perfectly adapted generation mix to be installed in a market context under different pricing rules. We base our analysis on a very detailed long-term greenfield capacity expansion optimization of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints are considered in the simulation (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.). These three technologies are chosen to represent base-load, mid-load, and peak-load plants. The mix is optimized to supply the chronological hourly demand of Spain for 2012 (assumed to be perfectly inelastic). This mix includes a fixed level of RES-E penetration assuming its remuneration is not provided by the DAM but through some additional payment mechanism. The effect of renewable energy sources is represented by means of a high penetration of solar photovoltaic (PV). The exogenous PV production profile has been scaled from the 2012 hourly production profile in Spain and in the short-term simulation the PV power output can be curtailed when needed for optimized operation.

Figure 8 aims at illustrating the different stages of the implemented methodology, while the following sections detail the operation of each element of the model.

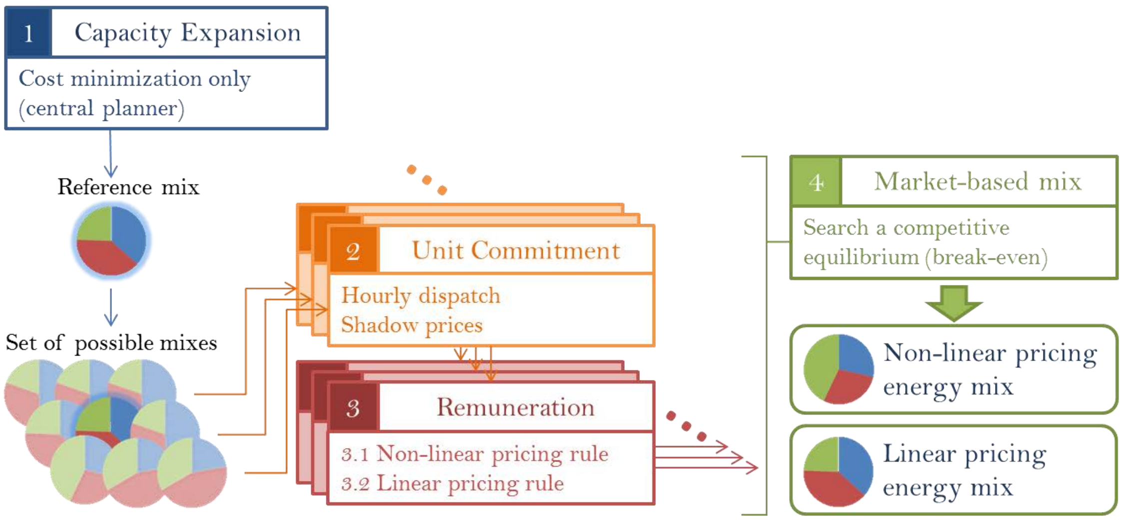

Figure 8. Methodology summary diagram.

3.1.1 Module 1: Reference generation mix

Module 1 calculates the least-cost energy mix using a traditional capacity expansion model as in a centralized planning case[12]. This energy mix is used only as initial reference for the subsequent search of the perfectly adapted mix corresponding to each of the pricing rules. Since in principle market prices are believed to drive investment towards the least cost generation mix, we assume that the market-based mixes to be obtained later will not deviate substantially from this reference, although as it is right next described, we explore up to around 4000 different alternatives.

We build a set of possible mixes by considering all combinations of the three thermal generation technologies which amount to n^3 possibilities (where n is the maximum number of units considered for each technology). In a real size example this produces a number of possibilities in the order of 10^6. We reduce the search by excluding those mixes that significantly deviate from the initial reference to handle some thousand combinations only. This way, the computation time in following modules is minimized while maintaining an extensive set of possible solutions, so that an optimum can be found.

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

3.1.2 Module 2: Short-term Unit Commitment

Module 2 takes as an input a given energy mix and simulates the day-ahead market outcome for a full year. The output of this module includes the detailed economic dispatch and the hourly marginal costs.

We consider a single node system, so no locational marginal prices (LMP) are produced. This way prices will have the same impact on each investment decision regardless of the location of power plants. In turn, price influence on investment behaviour will be easier to analyse. We assume perfect competition, so generators are supposed to declare their true marginal and non-convex costs. The UC formulation is detailed in Section 3.3.2.

3.1.3 Module 3: Price and remuneration calculation

Module 3, from the dispatch and marginal costs given by module 2, calculates the remuneration of each of the generation units committed, computing first the

[12] The model used in this step includes a detailed representation of both expansion and operation. The formulation is similar to that of presented later in Section 3.3.2, but the number of units available of each technology is in this case variables to be determined by the problem itself. To do so, associated investment costs are included in the objective function.

corresponding hourly prices and as a result the side-payments needed for the units to recover their full short-term operation costs under two different pricing rules.

The computation of prices and side-payments is detailed in Section 3.3.3 and 3.3.4. No reserves or other ancillary services are considered in this simulation since our interest is on differences produced exclusively by the aforementioned pricing rules on the day ahead energy-only market[13].

3.1.4 Module 4: Market-based mix search

Module 4 compares all the previously evaluated generation mixes to obtain, for each of the pricing rules, the best adapted mix. This direct search approach is similar to that of Shortt et al. (2013), who, to calculate a least cost portfolio, evaluated all possibilities separately and then chose the optimal solution by direct search. In our case the desired energy mix for each pricing rule is not the one minimizing total costs, instead, we consider as optimal the mix that a competitive market would choose to invest on. The corresponding market-based optimality conditions are based on the condition that all agents are break-even. In other words, an agent would choose to invest if and only if short-term market remuneration fully ensures the recovery of both investment and operation costs. On the other hand, a perfect competitive market will ensure that the short-term remuneration exactly recovers the previous costs[14]. The details are provided in Section 3.3.5.

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

[14] If the market remuneration was above these costs, competitors would enter the market and depress prices down to the break-even point.

3.2 Materials

The totality of the models used in this project has been implemented by the author using mainly three computing tools. GAMS has been used to code and run optimization based models. MATLAB has been used to code custom algorithm based models, to analyse and plot data and to perform the flow control of the overall model. EXCEL has been used as a user friendly data input interface and to perform data processing and analysis.

3.2.1 GAMS & CPLEX

The General Algebraic Modeling System (GAMS) is a high-level algebraic modeling system for large scale optimization. The GAMS language is formally similar to commonly used programming languages and provides a simple interface to facilitate the edition of the code. GAMS offers a choice of solver packages to perform the optimization computation. In this case CPLEX was the optimizer used. CPLEX is a reliable commercial optimizer which continues to be actively developed by IBM.

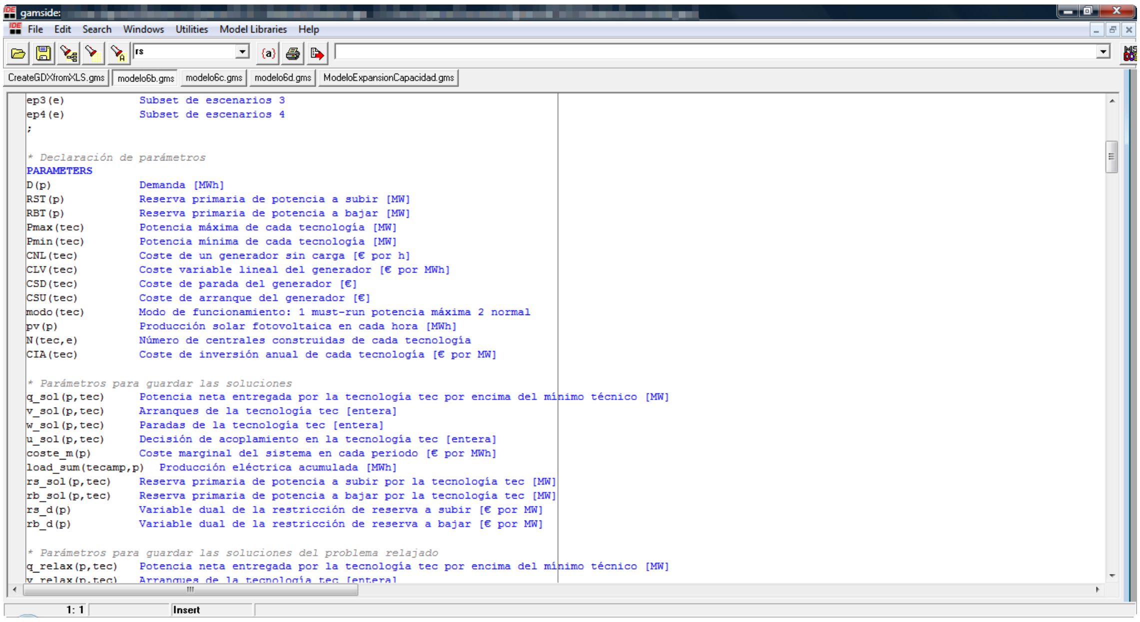

Figure 9. GAMS interface sample

Figure 10 shows which components of the model have been developed using GAMS. Modules 1, 2 and 3 require MILP (mixed integer linear programming) solving which is easy to formulate and solve using GAMS.

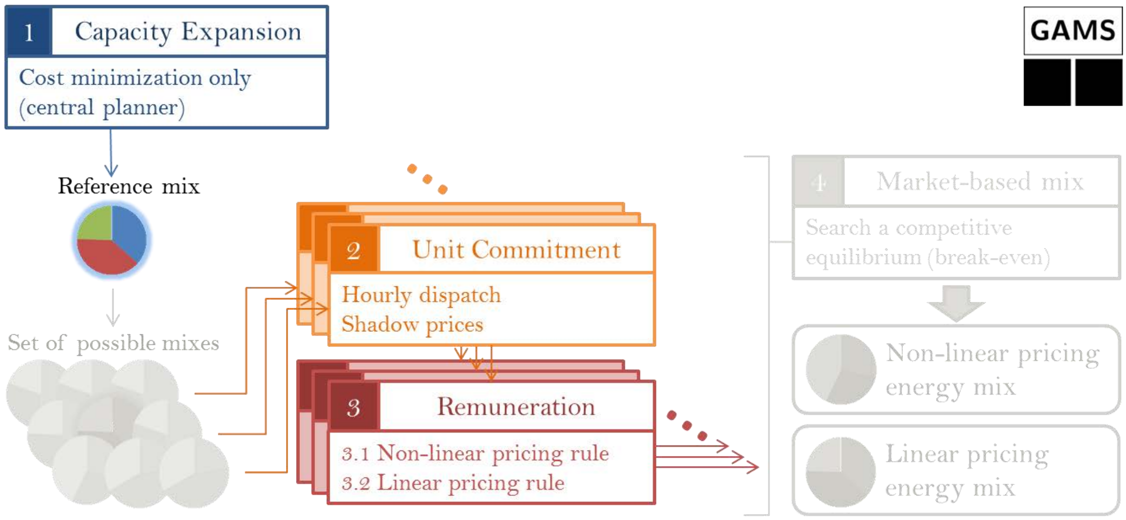

Figure 10. GAMS components of the model

3.2.2 *EXCEL & VBA*

Excel is a spreadsheet application developed by Microsoft and forms part of the Microsoft Office software package. It allows for simple data analysis and representation. It is used here as a user friendly data input interface. Excel also allows to automate repetitive tasks using VBA (Visual Basic for Applications), a macro programming language. VBA is used here to automatically generate the set of possible mixes between modules 1 and 2 according to a number of user-defined options.

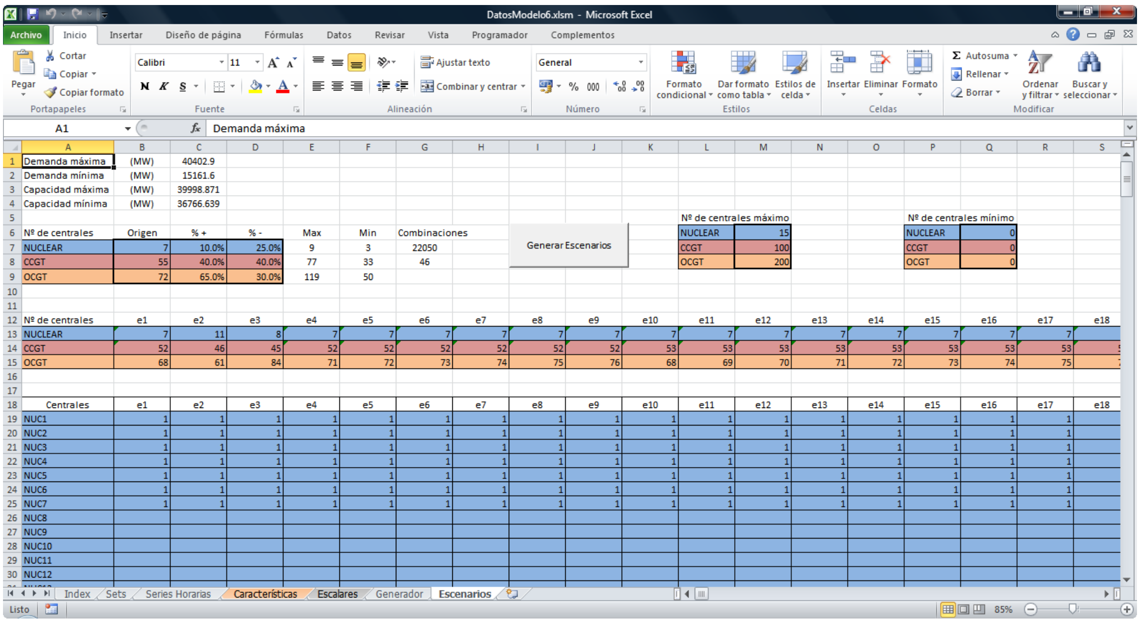

Figure 11. Excel interface sample

Figure 12 highlights the tasks performed by Excel in the model. The information is exchanged between GAMS and Excel using GDX (GAMS data exchange) files. The GAMS software includes the tools needed to produce GDX files from an Excel spreadsheet and vice-versa.

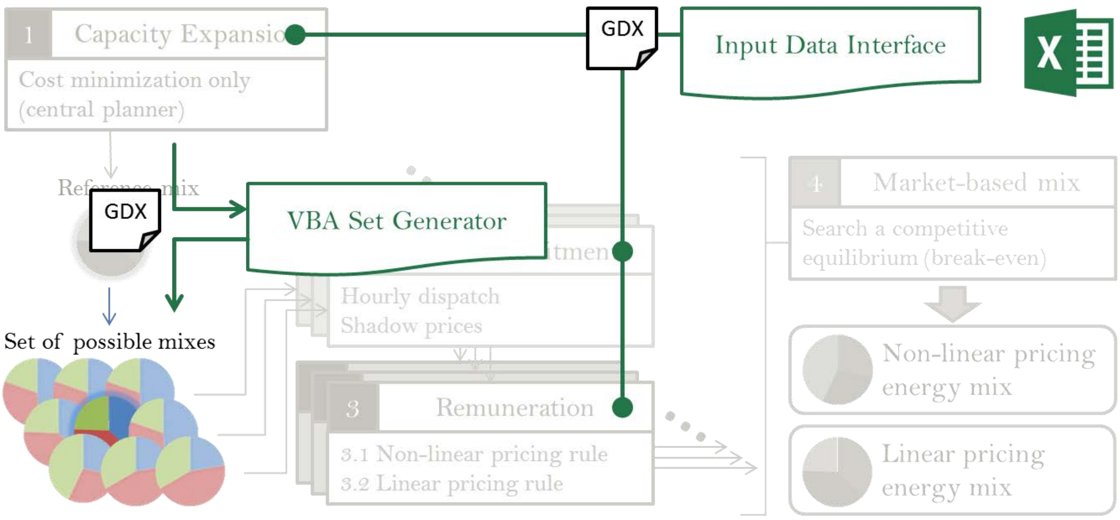

Figure 12. Excel components of the model

3.2.3 MATLAB

MATLAB (matrix laboratory) is a numerical computing environment and high level programming language. It allows for data manipulation, plotting of results and interfacing with other programs. These interfacing features allowed using MATLAB to unify all the components of the model into one tool which greatly simplified running the model consecutively under different scenarios.

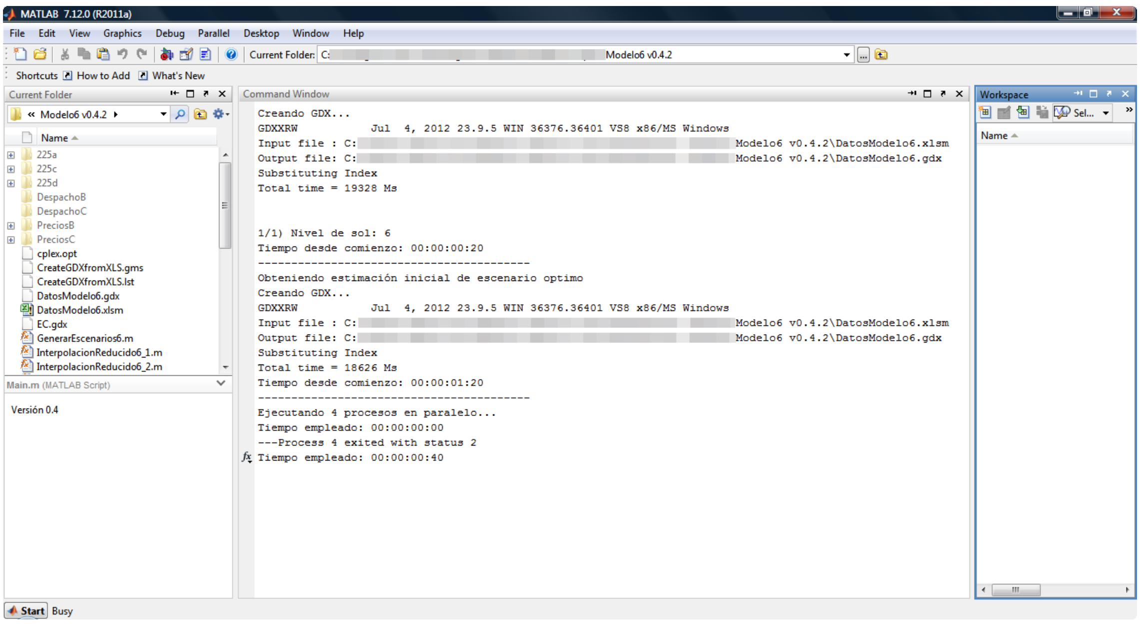

Figure 13. Matlab interface sample

As shown in Figure 14, MATLAB performs the module 4 search algorithm. Also, the flow control of all other modules and the interaction and data exchange among them is managed through MATLAB. MATLAB is also capable of reading and writing GDX files which enables data exchanges between modules 3 and 4.

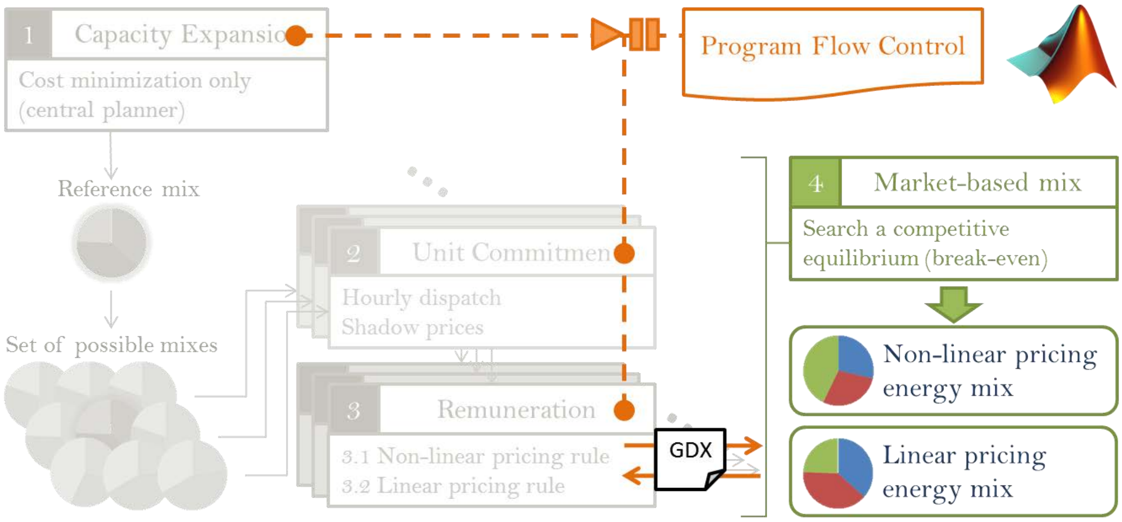

Figure 14. Matlab components of the model

3.3 Theory/Calculation

3.3.1 Capacity Expansion Model formulation

A capacity expansion model takes as an input the operational and investment cost data of each generating technology and the forecasted demand for a year. With these data the model decides which is the least cost generation mix that could possibly be installed. This type of model is often used as a planning tool but in our case the least cost generation mix is only used as a reference. Because of this reference only purpose, various types of capacity expansion models could be appropriate. However, the model that has been chosen uses a similar formulation to that of the unit commitment model described in Section 3.3.2 to make the results easier to compare.

Nomenclature

Indexes and sets

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

Parameters

C_g^{LV}	Linear variable cost of a unit of technology g [$/MWh]
C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]
C_g^{SU}	Start-up cost of a unit of technology g [$]
C_g^{AI}	Annualized capital cost of a unit of technology g [$/MW-year]
D_t	Load demand in hour t [MWh]
PV_t	Solar photovoltaic available production in hour t [MWh]
$\bar{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]
RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
$\bar{N}_g$	Maximum number of units of technology g that can be installed
$\underline{N}_g$	Minimum number of units of technology g than can be installed

Variables

nse_t	Non-served energy in hour t [MWh]

$p_{g,t}$	Power output at hour t of all technology g units above the minimum output $\underline{P}_g$ [MW]
pv_t^{spill}	Solar photovoltaic energy spill in hour t [MWh]
$u_{g,t}$	Number of units of technology g committed at hour t
$v_{g,t}$	Number of units of technology g starting-up at hour t
$w_{g,t}$	Number of units of technology g shuting-down at hour t
n_g	Optimal number of units of technology g to be installed

Formulation

$$\min \sum_{t\in T}\left[\sum_{g\in G}\left[C_g^{NL}u_{g,t}+C_g^{LV}\left(\underline{P}_g u_{g,t}+p_{g,t}\right)+C_g^{SU}v_{g,t}+C_g^{SD}w_{g,t}\right]+C^{NSE}nse_t\right] + \sum_{g\in G}\left[C_g^{AI}\overline{P}_g n_g\right] \quad (11)$$

$$s.t. \quad \sum_{g\in G}\left\lfloor \underline{P}_g u_{g,t}+p_{g,t}\right\rfloor + PV_t - pv_t^{spill} = D_t - nse_t \qquad \forall t \quad (12)$$

$$u_{g,t}-u_{g,t-1}=v_{g,t}-w_{g,t} \qquad \forall g\notin G^{MR},t \quad (13)$$

$$p_{g,t}\le\left(\overline{P}_g-\underline{P}_g\right)u_{g,t} \qquad \forall g\notin G^{MR},t \quad (14)$$

$$p_{g,t+1}-p_{g,t}\le RU_g \qquad \forall g\notin G^{MR},t \quad (15)$$

$$p_{g,t-1}-p_{g,t}\ge RD_g \qquad \forall g\notin G^{MR},t \quad (16)$$

$$0\le u_{g,t}\le n_g \qquad \forall g\notin G^{MR},t \quad (17)$$

$$\underline{N}_g\le u_{g,t},v_{g,t},w_{g,t},n_g\le\overline{N}_g, \quad u_{g,t},v_{g,t},w_{g,t}\in\mathbb{Z} \qquad \forall g\notin G^{MR},t \quad (18)$$

$$p_{g,t}=N_g\left(\overline{P}_g-\underline{P}_g\right) \qquad \forall g\in G^{MR},t \quad (19)$$

$$u_{g,t}=n_g, \quad v_{g,t},w_{g,t}=0 \qquad \forall g\in G^{MR},t \quad (20)$$

$$\underline{N}_g\le u_{g,t},n_g\le\overline{N}_g, \quad u_{g,t},n_g\in\mathbb{Z} \qquad \forall g\in G^{MR},t \quad (21)$$

$$pv_t^{spill}\le PV_t \qquad \forall t \quad (22)$$

$$p_{g,t},nse_t,pv_t^{spill}\ge 0, \quad p_{g,t},nse_t,pv_t^{spill}\in\mathbb{R} \qquad \forall g,t \quad (23)$$

Equation (11) gives the objective function to be minimized; this value is the total cost of fulfilling the forecasted demand. The cost includes annual investment expenditure;

therefore, the set T should include hourly periods representing a whole year. Otherwise the capital cost should be adjusted to represent a fraction of a year only. Must-run generators are considered to be online at all times so as required by equation (20) the variables $u_{g,t}$ and n_g always have the same value. For non must-run generators the number of online units has to be lower than the number of installed units as described by equation (17).

3.3.2 Unit Commitment formulation

An accurate short-term simulation is necessary to obtain precise results in the long term. Our first attempt was to use a complete UC as the one presented in Morales-España et al. (2013) to simulate the short-term operation of the day-ahead market for a whole year. This approach made the problem computationally intractable so our next step was to reduce the number of variables by considering only a few representative weeks instead of a year. This approach could have been successful for other purposes but it was not appropriate for ours. This is because important discontinuities that affect the long-term problem are introduced when this simplification is applied.

For example, the amount of time intervals with scarcity of capacity is a key issue to determine the long-term adequacy of an energy mix. When generation capacity is insufficient the market price is set at the so-called non-served energy (NSE) price. If properly determined (i.e. if turns to be a good proxy of demand's utility), this price is the required remuneration to promote the properly adapted investment in capacity, and it is crucial to allow for the investment cost recovery of all units in general and peak-load units in particular. If only a few weeks are considered in the problem a discontinuity is introduced in the number of time intervals in which the price is at the NSE level. For example, if four weeks were considered and the result was then scaled to a year, the number of intervals with NSE price in a week would be multiplied by thirteen. This discontinuity produces big differences in the remuneration of all units when small changes are made in the mix yielding unrealistic results. Therefore, a full year representation is needed.

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

Nomenclature

Indexes and sets

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

Parameters

C_g^{LV}	Linear variable cost of a unit of technology g [$/MWh]
C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]
C_g^{SU}	Start-up cost of a unit of technology g [$]
D_t	Load demand in hour t [MWh]
PV_t	Solar photovoltaic available production in hour t [MWh]
$\bar{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]
RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
N_g	Number of units installed of technology g

Variables

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

Formulation

$$\min \sum_{t \in T} \left\lfloor \sum_{g \in G} \left[C_g^{NL} u_{g,t} + C_g^{LV} \left(\underline{P}_g u_{g,t} + p_{g,t} \right) + C_g^{SU} v_{g,t} + C_g^{SD} w_{g,t} \right] + C^{NSE} nse_t \right\rfloor \quad (24)$$

$$s.t. \quad \sum_{g \in G} \left\lfloor \underline{P}_g u_{g,t} + p_{g,t} \right\rfloor + PV_t - pv_t^{spill} = D_t - nse_t \qquad \perp \rho_t \qquad \forall t \quad (25)$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \qquad \forall g \notin G^{MR}, t \quad (26)$$

$$p_{g,t} \le \left(\bar{P}_g - \underline{P}_g\right) u_{g,t} \qquad \forall g \notin G^{MR}, t \quad (27)$$

$$p_{g,t+1} - p_{g,t} \le RU_g \qquad \forall g \notin G^{MR}, t \quad (28)$$

$$p_{g,t-1} - p_{g,t} \ge RD_g \qquad \forall g \notin G^{MR}, t \quad (29)$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{Z} \qquad \forall g \notin G^{MR}, t \quad (30)$$

$$u_{g,t} = N_g, \quad v_{g,t}, w_{g,t} = 0 \qquad \forall g \in G^{MR}, t \quad (31)$$

$$p_{g,t} = N_g \left(\bar{P}_g - \underline{P}_g\right) \qquad \forall g \in G^{MR}, t \quad (32)$$

$$pv_t^{spill} \le PV_t \qquad \forall t \quad (33)$$

$$p_{g,t}, nse_t, pv_t^{spill} \ge 0, \quad p_{g,t}, nse_t, pv_t^{spill} \in \mathbb{R} \qquad \forall g, t \quad (34)$$

Equation (24) shows the objective function to be minimized which is a sum of all operation costs (no-load cost, linear-variable cost, start-up cost and shut-down cost) and the value of the non-served energy. Restriction (25) equals production (allowing solar PV production to be reduced by a certain amount if needed) with demand minus non-served energy. As well-known, its dual variable ρ_t represents the marginal cost of the system for each time interval. As shown in equation (30), binary variables are here integer with the upper bound being the number of units installed. In this model we consider a must-run restriction for nuclear power plants so the constraint (32) fixes the power output to its maximum. For an extensive description of a UC model see Morales-España et al. (2013).

3.3.3 Non-linear (discriminatory) pricing rules

Non-linear pricing rules are the most extended alternative in markets with complex auctions. This is the case of most US markets such as NYISO (2013), MISO (2014) or ISO-NE (2014)[15].

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

[15] A relevant excerpt of the manuals that detail the calculation of prices in these markets has been included in the Appendix section.

price-based market remuneration[16]. The difference generally considers the complete day costs and incomes (i.e. side-payments are calculated on a daily basis, not hourly) and only exists if the difference is positive (if costs happen to be higher than market remuneration).

This project follows this simple approach to compute non-linear prices[17] and side-payments according to:

$$\text{UniformPrice}_t = \rho_t \tag{35}$$

$$\begin{aligned} SP_{j,day} = \max\{ & \\ & 0, \\ & \sum_{t \in day} \underbrace{C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}} + \\ & -\sum_{t \in day} \underbrace{\rho_t (\underline{P}_j u_{j,t} + p_{j,t})}_{\text{Market Remuneration}} \\ & \} \end{aligned} \tag{36}$$

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

$$DI_{j,day} = \sum_{t \in day} \rho_t \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{37}$$

The daily profit made by a generator is calculated in equation (38). Observe that the profit cannot be calculated for a period shorter than a day since the side-payment depends on the whole day costs and incomes and therefore cannot be assigned to certain hours only. Also, it is guaranteed that the daily profit at any given day for any generator has a lower bound of zero.

$$DP_{j,day} = DI_{j,day} - \sum_{t \in day} [\underbrace{C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}}] \tag{38}$$

[16] Again, here we have restricted the scope of the paper to the energy only day ahead market. When adding in the analysis more products or subsequent markets, the side-payments may include other concepts such as the opportunity cost derived from providing reserves.

[17] Some more refined methods to calculate side-payments are worth mentioning -see for example O'Neill et al. (2005)- although not representative of current market practices.

3.3.4 Linear (non-discriminatory) pricing rules

Linear pricing rules rely on a uniform price to account for variable and fixed (non-convex) costs at the same time. This can be achieved in a number of ways: different authors propose alternative pricing mechanisms to reflect non-convexities in the marginal price perceived by all units (see for example Vázquez (2003), Hogan and Ring (2003), Gribik et al. (2007) which minimize side-payments or Ruiz et al. (2012) which completely eliminates side-payments). These methods seek to minimize side-payments and find a price that truly captures the value of energy (this is the reason why they are called non-discriminatory, although in most cases some sort of side-payments are still needed)[18].

Since side-payments would still be necessary in most cases (although minimal), this approach, strictly speaking, should still be considered discriminatory. On this paper though, we will refer to these pricing rules as linear representing the fact that non-convexities are considered in price formation and distinguishing it from the non-linear rule previously introduced.

All of the mentioned alternatives are similar in nature although very different in its implementation. Probably the most promising alternative is the convex-hull pricing (Gribik et al., 2007) which is the foundation of the recently accepted MISO proposal of extended locational marginal pricing (ELMP).[19] The method proposed by MISO does not follow completely the convex-hull methodology (or full-ELMP) in favour of a computationally simpler formulation. This simplified method is based on virtually allowing fractional commitment of some units, even though fractional commitment is not physically feasible, and allocating the corresponding share of non-convex costs on the market price.

We chose to use a similar approach, generally referred to as "Dispatchable Model". It consists in a modification of the unit commitment model used for dispatch in which binary restrictions are relaxed. This way some units are partially committed and now, marginal costs depend on non-convex costs since an additional unit of energy would require an increase in the continuous commitment variable. Only equation (30) needs to be changed to:

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{R} \qquad \forall g \notin G^{MR}, t \quad (39)$$

[18] A real case example is the pricing rule implemented in Ireland (SEMO, 2014) where an ex-post optimization model increases marginal prices in the least costly way until all units recover their declared costs. In this case no side-payments are needed and all units perceive the same price. Appendix D summarizes this price calculation alternative.

[19] See MISO (2013) and FERC (2012).

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

$$\text{UniformPrice}_t = \rho_t^{relax} \tag{40}$$

$$\begin{aligned} SP_{j,day} = \max\Big\{ & \\ & 0, \\ & \sum_{t \in day} \underbrace{C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}} + \\ & -\sum_{t \in day} \underbrace{\rho_t^{relax} (\underline{P}_j u_{j,t} + p_{j,t})}_{\text{Market Remuneration}} \\ & \Big\} \end{aligned} \tag{41}$$

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

$$DI_{j,day} = \sum_{t \in day} \rho_t^{relax} \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{42}$$

Note that the dispatch remains the same as in the non-linear case; the linear pricing rule only affects the remuneration by producing a higher uniform price through the dual variable of the relaxed problem which reduces the side-payments requirements.

The daily profit of a generator is formulated exactly as in the non-linear case but the result will of course be different since the daily income term used in the equation has changed considering the relaxed price as described above.

$$DP_{j,day} = DI_{j,day} - \sum_{t \in day} [\underbrace{C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}}] \tag{43}$$

3.3.5 Market-based mix search

To illustrate our methodology to find the perfectly adapted mix, first consider the following simple case with only two generation technologies. In order to determine how much capacity of each of the technologies will be installed, all possible combinations of technology one (T1) and technology two (T2) are represented in the plane shown in Figure 15.

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

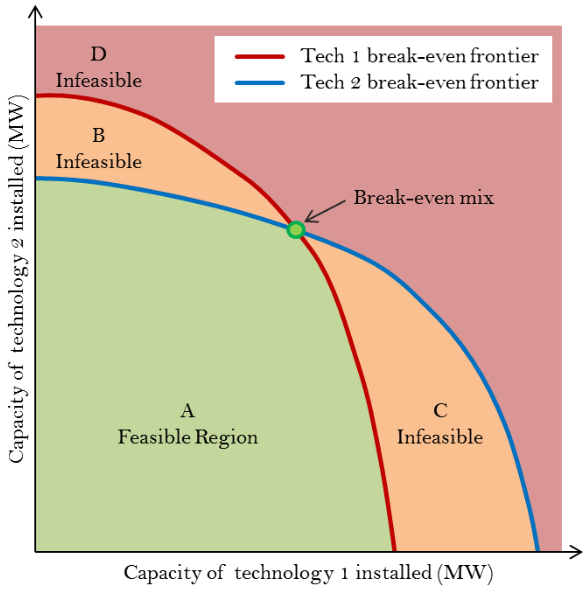

Figure 15. Continuous investment break-even mix

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

Figure 16 represents this methodology applied to a discrete investment problem, which is our case. Break-even frontiers can be interpolated from the point cloud and the continuous break-even mix obtained as the intersection. However, we are considering the more realistic discrete investments which present a lumpiness problem. As illustrated in the figure, no point will probably coincide with the continuous break-even mix and various discrete energy mixes may seem valid under the break-even criteria. To discern which of these nearly optimal points is preferred, the value of the net social benefit (NSB) resulting under each of the mixes is compared and the NSB-maximizing mix is selected.

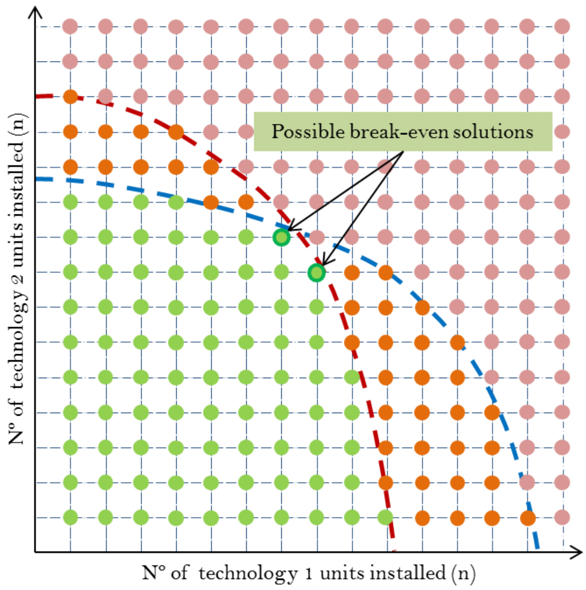

Figure 16. Discrete investment break-even mix

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

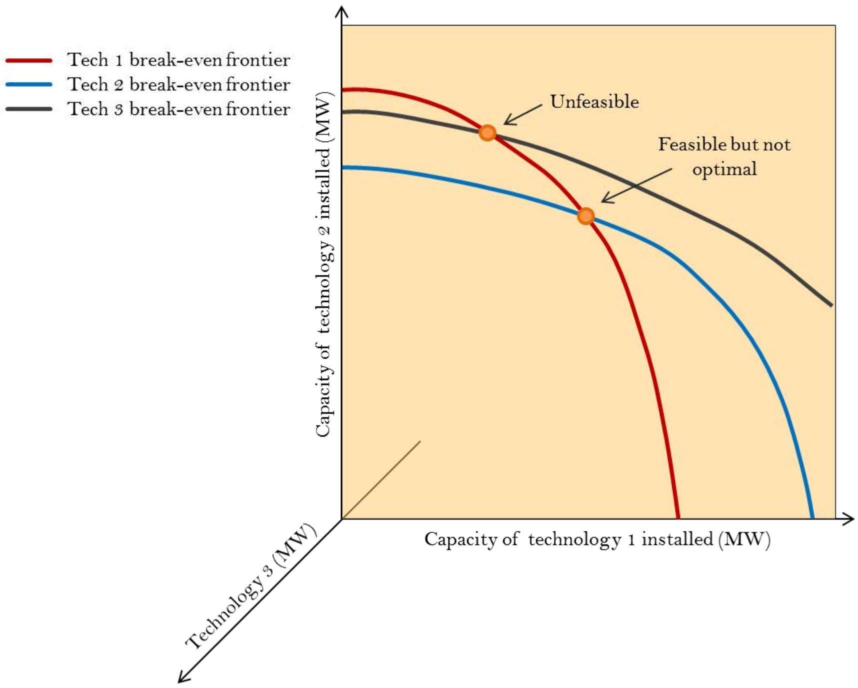

Figure 17. Break-even extension to 3-dimensions

Figure 17 illustrates the effect of adding a third technology into the previous discussion. A fixed capacity of T3 is installed, the plane represented in Figure 17 includes any combination of T1 and T2 with a constant capacity of T3. It is possible again to divide this plane into two regions with respect to T3 investment cost recovery. T3 break-even frontier lies out of the previous feasible region, therefore no equilibrium can be reached. One of the intersection points is unfeasible because the T2 capacity required to be installed is unprofitable. There is a feasible intersection which makes all technologies profitable but the competitive equilibrium is not reached in that case since additional T3 capacity seems to still be profitable.

For any given amount of T3 capacity added to the possible combinations, a new plane is created with all combinations of T1 and T2 but only one possible level of T3. This is represented in Figure 18, for one of the planes the three lines intersect at one point only. This point is both feasible and represents a competitive equilibrium so it is the desired break-even solution.

This should clarify the previous statement saying break-even frontiers become surfaces in the three dimensional case. If all the combinations of T1, T2 and T3 are considered, an infinite number of planes would be added to Figure 18 creating the mentioned surfaces. Since we are interested in discrete investments, only a limited number of planes is needed.

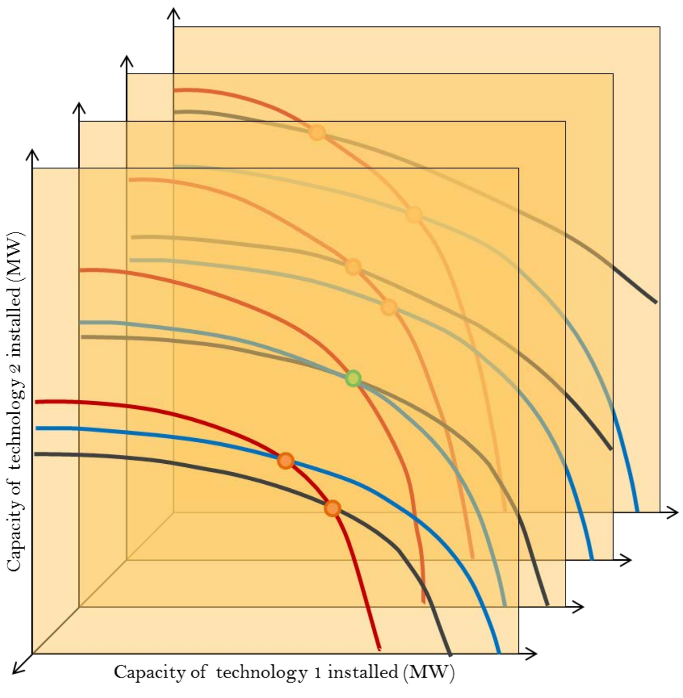

Figure 18. Break-even solution for a 3-dimensional case

Again, the discrete investment problem will most likely have various nearly optimal solutions but no solution will totally coincide with the continuous break-even solution. The criteria used to select one solution only is also to choose the NSB maximizing mix among those that satisfy the break-even conditions.

Formulation

Next, the general formulation of this problem is presented.

$$AP_g = \min \left\{ \sum_{day \in year} DP_{j,day} \right\}_j \tag{44}$$

AP_g is the annual profit made by the less profitable generator of a technology *g*. The less profitable unit is selected because this is the unit making the difference between a situation in which all units of a technology recover their investment costs and an unfeasible situation in which one or more of the units are unprofitable.

This annual profit can be calculated for any of the considered combinations of power plants built around the reference mix given by module 1. Each of the mixes will be denoted by $m \in M$. The solution to be found is one of this mixes. The annual profit corresponding to a particular technology *g* under a given mix will be written as AP_g^m.

A given mix needs to be compared against a mix containing the same combination of generating units plus an additional unit of technology *g*. This variation of the mix *m* will be denoted by *m*+*g*. In the expression AP_g^{m+g} the technology *g* referenced by each of the indexes is the same. This profit will be used to determine if an additional unit of *g* with respect to a given mix results in a profitable or unprofitable mix.

Finally, the model can be summarized as follows:

$$\max_m NSB \tag{45}$$

$$\frac{AP_g^m}{C_g^{AI}} \geq 1 \qquad \forall g \in G \tag{46}$$

$$\frac{AP_g^{m+g}}{C_g^{AI}} \leq 1 \qquad \forall g \in G \tag{47}$$

Restriction (46) eliminates unfeasible mixes (if some technologies are unprofitable) and restriction (47) discards those mixes in which no competitive equilibrium has been reached (if an additional investment in any of the technologies could still be profitable). Among the mixes that satisfy equations (46) and (47), the one maximizing NSB is selected as specified by equation (45).

Note that in the continuous investment problem, the expression in equation (46) would be strictly equal to one and only one mix would satisfy this criterion making all other equations unnecessary.

CHAPTER 4. RESULTS AND DISCUSSION

4.1 Generation mix obtained for each pricing rule

As exposed previously, the main goal of this model is to find, for two different pricing rules, the perfectly adapted generation mix that would be installed under market-driven investment decisions.

This section provides the results obtained by the model. Three different energy mixes are calculated and compared. First, the least-cost (reference) energy mix from a centralized perspective is obtained as described by module 1. Around this reference mix a set of possible mixes containing 3706 potential solutions is built. All these possibilities are characterized by modules 2 and 3. Module 4, considering market-based investment decisions, selects the two mixes that best adapt to a non-linear and a linear pricing rule. These results are obtained in a context of a rather significant solar PV penetration (19.2 GW-peak) in a power system supplying the chronological hourly demand for Spain 2012 (40.4 GW-peak). The data used to represent each power plant type is summarised in Table i.

Table i: Generating technologies characteristics[20]

	$\overline{P}_g$	$\underline{P}_g$	RU_g	RD_g	C_g^{AI}	C^{LV}	C^{NL}	C^{SD}	C^{SU}
	MW	MW	MW/min	MW/min	K$/MW-year	$/MWh	$/h	$	K$
OCGT	150	60	12	12	78.58	104	1650	-	14.75
CCGT	400	160	10	10	142.8	57	2440	-	28.33
NUCLEAR	1000	500	-	-	590.0	8.5	1500	-	-

$C^{NSE} = 5000$ $/MWh

Figure 19 shows first the minimum cost reference mix followed by the mixes resulting from applying the two different pricing rules considered. Both the mix produced by the linear pricing rule and the mix produced by the non-linear pricing rule deviate from the reference mix. In fact, none of the pricing rules supports the reference energy mix (i.e. they do not provide sufficient remuneration to make all units in the reference mix profitable), which would be a desirable characteristic of a pricing rule. Both pricing rules require a deviation from the reference mix including a slight decrease in

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

total capacity. This deviation though, is significantly smaller when the linear pricing rule is applied.

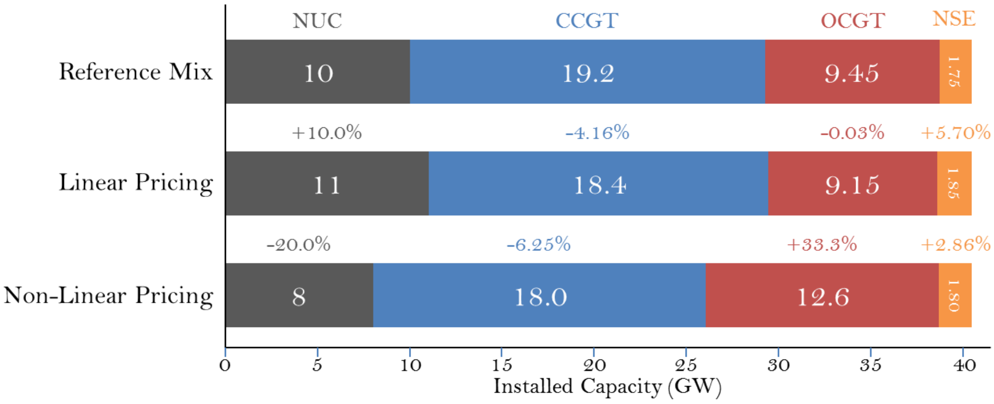

Figure 19. Generation mix results.

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

4.2 Investment signals analysis

To gain more insight, the representation presented in Section 3.1.4 has been extended to include three technologies and the results of this simulation are shown in Figure 20 and Figure 21 Doing this requires an extension to 3 dimensions but for the sake of clarity these figures show 2-dimensional break-even frontiers obtained for all combinations of CCGT and OCGT units and only discrete combinations of nuclear power plants. The number of nuclear power plants is indicated next to the corresponding break-even frontier by N#Plants.

These frontiers can be thought of as the contour lines of the three surfaces that should intersect only at the break-even solution point. This way, a point where all three contour lines intersect will indicate the desired solution but this point may not be represented in the figure since the optimal continuous solution could require a non-discrete level of nuclear capacity.

Figure 20 shows the result for the linear pricing rule. To easily find the point where all three surfaces intersect look at the crosses (+) which represent the intersection of the CCGT (blue) and OCGT (red) lines and the asterisks (*) which represent the intersection of the NUC (black) and OCGT (red) lines. The perfectly adapted generation mix to be installed under a linear pricing rule would have between 10 and 11 nuclear power plants. Since we are assuming that only discrete investments are possible the final solution maximizing NSB requires 11 nuclear power plants and is indicated by the green dot. The red diamond points the minimum cost reference mix, it is hard to tell with the figure but it is located outside of the feasible boundary.

The same analysis can be made for Figure 21 which shows the results for the non-linear pricing rule. The ideal solution would lie between 7 and 8 nuclear power plants but the discretization simplifies it to 8. In this case the perfectly adapted mix requires a totally different amount of OCGT capacity compared to the optimal reference mix.

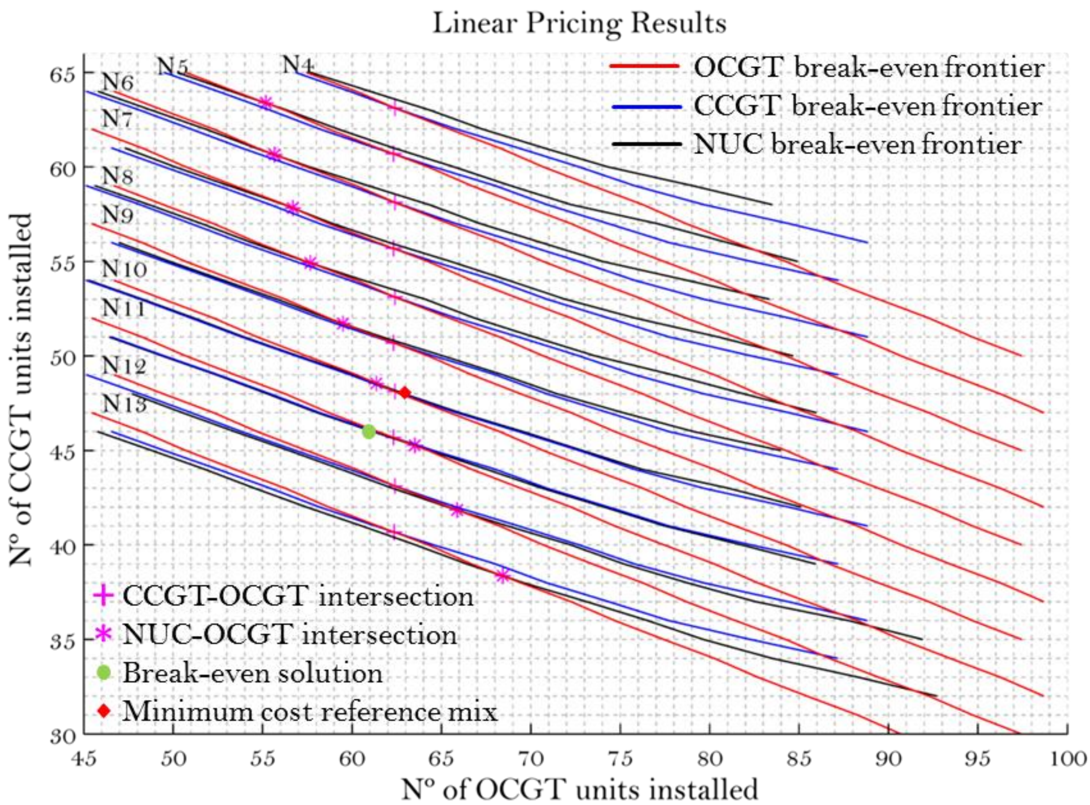

Figure 20. Break-even frontiers and solution under a linear pricing rule

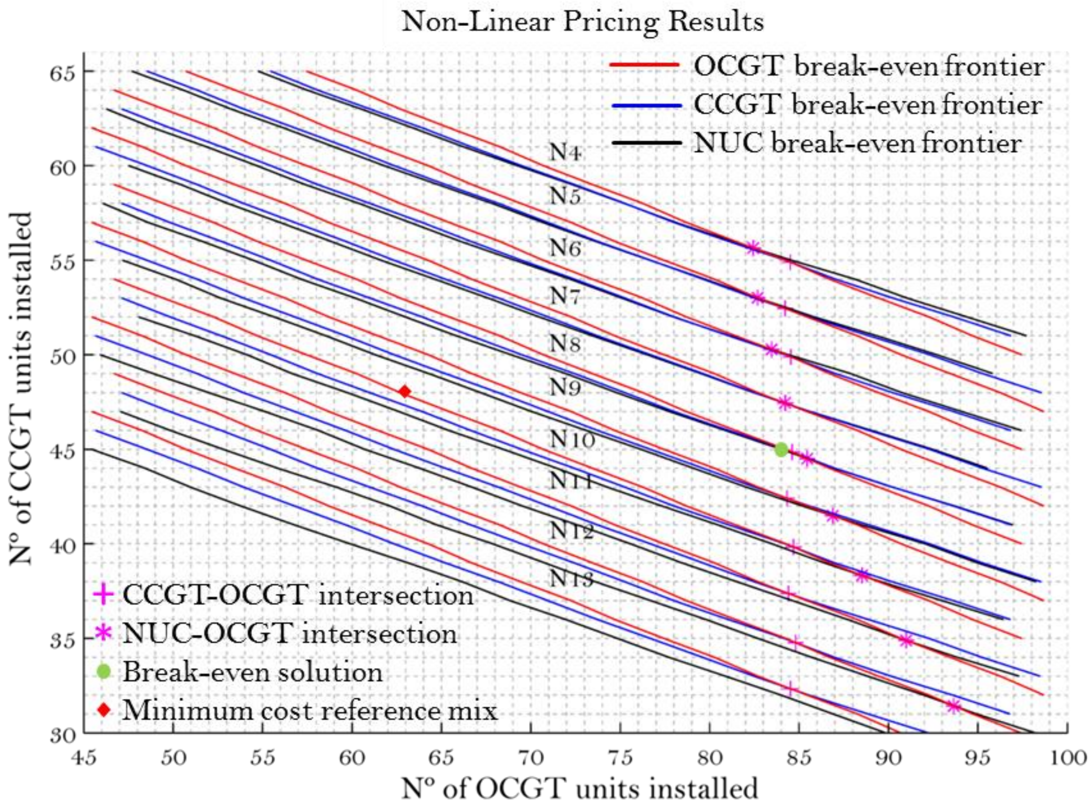

Figure 21. Break-even frontiers and solution under a non-linear pricing rule

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

Interestingly, OCGT break-even frontiers do not change after changing the pricing rule applied. This is a consequence of the peak-load regime of OCGT units; the least profitable OCGT unit, which is the one of interest in this problem, is never inframarginal. NUC and CCGT units are inframarginal in some cases and this provides them with higher prices under the liner pricing rule. These higher prices "lifts" their break-even frontiers making some additional investments profitable and therefore, requiring a lower peak-load capacity in the competitive equilibrium point.

4.3 Hourly prices analysis

In Figure 22 we sorted in descending order the hourly uniform prices produced by each of the pricing rules in the corresponding energy mix. The non-linear price consists of four different regimes; the price is set to C^{NSE} when not enough capacity is available, the other two steps correspond to OCGT and CCGT variable costs. Nuclear power plants can never be marginal since they are not able to regulate their output, therefore the price is set to zero when production exceeds demand and solar PV production is spilled. The linear pricing rule is not limited to these four steps and a continuum of prices is possible. Compared to the non-linear case, the price is lower when the additional nuclear power plants substitute CCGT units and when CCGT units replace OCGT units. Figure 23 illustrates how daily side-payments are, as expected, reduced by the linear pricing rule.

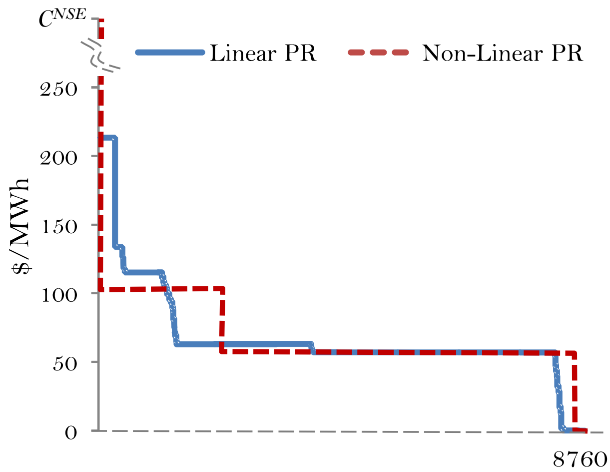

Figure 22. Monotone curve of uniform market prices

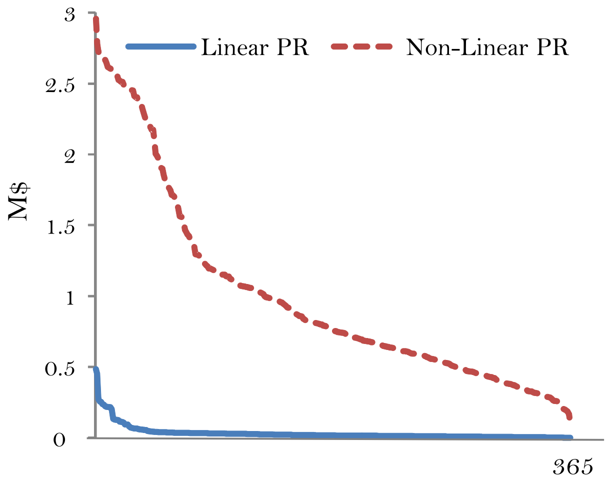

Figure 23. Monotone curve of daily side-payments

4.4 Total system cost analysis

This section aims to qualify the results presented previously, mainly to determine the relevance of the pricing rule and to clarify some common misconceptions.

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

$$TotalCost_{year} = \sum_{t \in year} nse_t C^{NSE} + \sum_j \sum_{t \in year} OperationCost_{j,t} + \sum_j C_j^{AI} \quad (48)$$

Figure 24 details the share of each component of total costs. It is clear that the linear pricing energy mix is composed of more capital intensive technologies with lower variable costs. Interestingly, the share of non-convex costs (no-load and start-up costs) is relatively small (around 7%) although these are responsible for the price differences between each of the pricing rules and thus, responsible for the difference in the final energy mix.

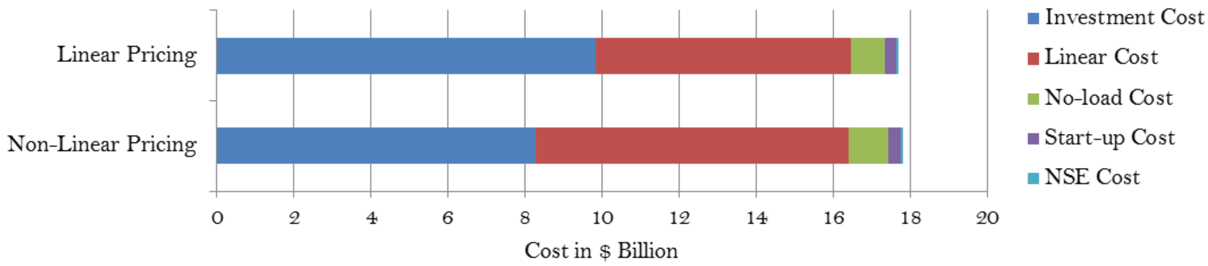

Figure 24. Cost structure of each generation mix

In particular, start-up costs only represent around 1.5% of total costs. This suggests that we could use the so-called screening curves (SSCC) method (Phillips et al., 1969) to gain some more insight on the results we are obtaining. The SSCC method relates the optimal generation mix to the variable and fixed cost of a generating technology through the load-duration curve of the system. This is actually a simplified method to simulate the dispatch disregarding non-convex costs; the variable production cost of a generating unit is considered constant internalizing averaged no-load and start-up costs. These assumptions consider perfect merit-order effect which means that a particular technology will only be generating electricity if all the technologies with lower variable costs are producing as well. In this simplification, investment is considered continuous and only the total capacity (MW) to be installed is obtained.

Figure 25 shows this traditional approach. The total production cost curve per installed MW for each technology is represented as a function of the number of production hours (firing hours). The intersections of these curves determine the number of hours of production that separate the annual regimes where the different technologies are optimal. The least-cost technologies are thus determined by the lower envelope curve. Installed capacities are determined by simple inspection in the net load duration curve.

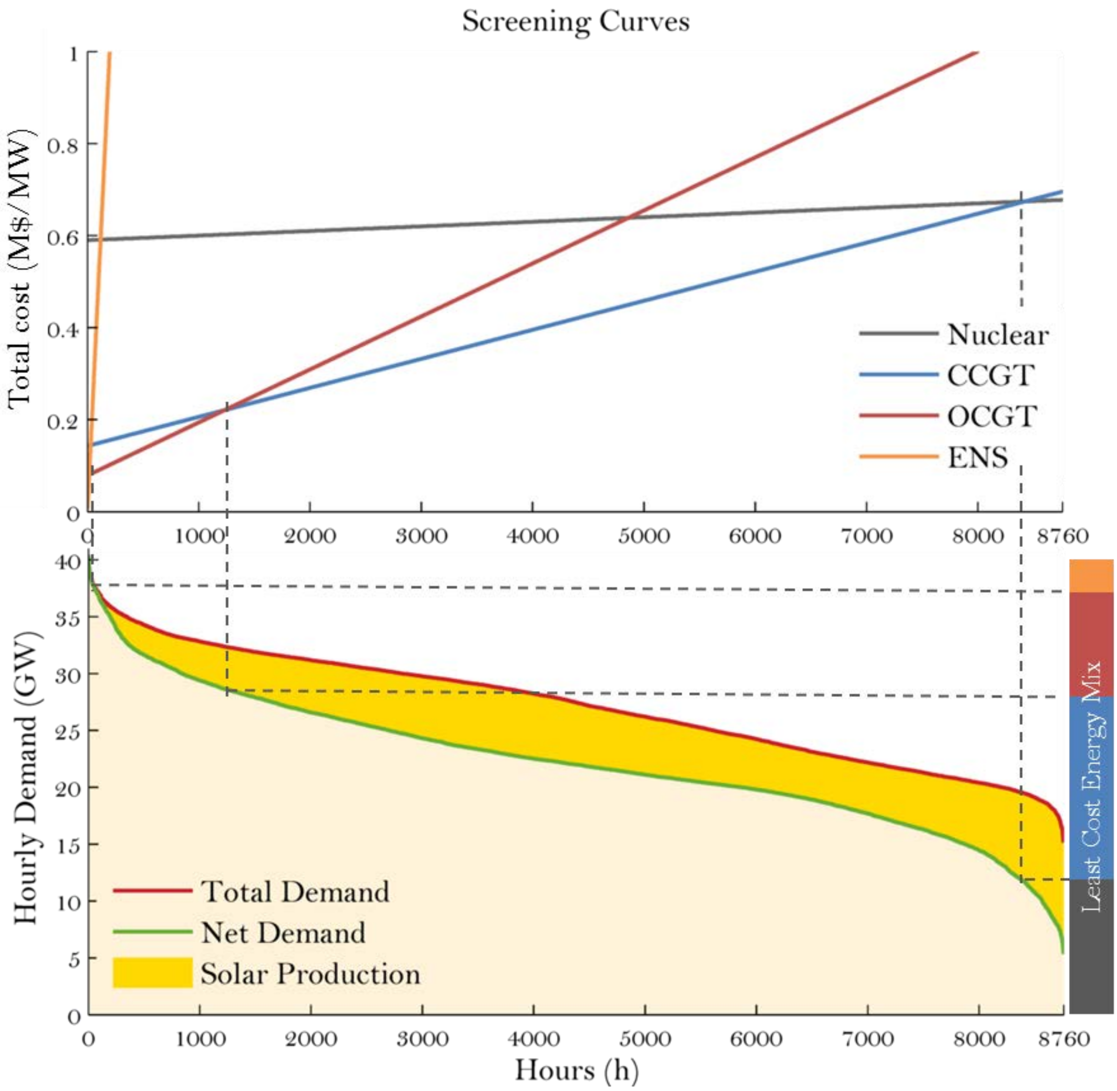

Figure 25. Traditional Screening Curves Method

We use an alternative representation of the SSCC (Figure 26), where the total production cost curve for each technology is represented as a function of the loading point. This way, the horizontal directly indicates the capacity to be installed. This simply requires a change of variable using the relation between time and power given by the net load-duration curve of the system[21]. The area under each curve represents the costs incurred when a certain capacity of each technology is installed.

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

In this type of representation we get the total cost involved when instaling a MW of each of the technologies at each of the load levels (under the simplified dispatching assumptions of the SSCC methodology).

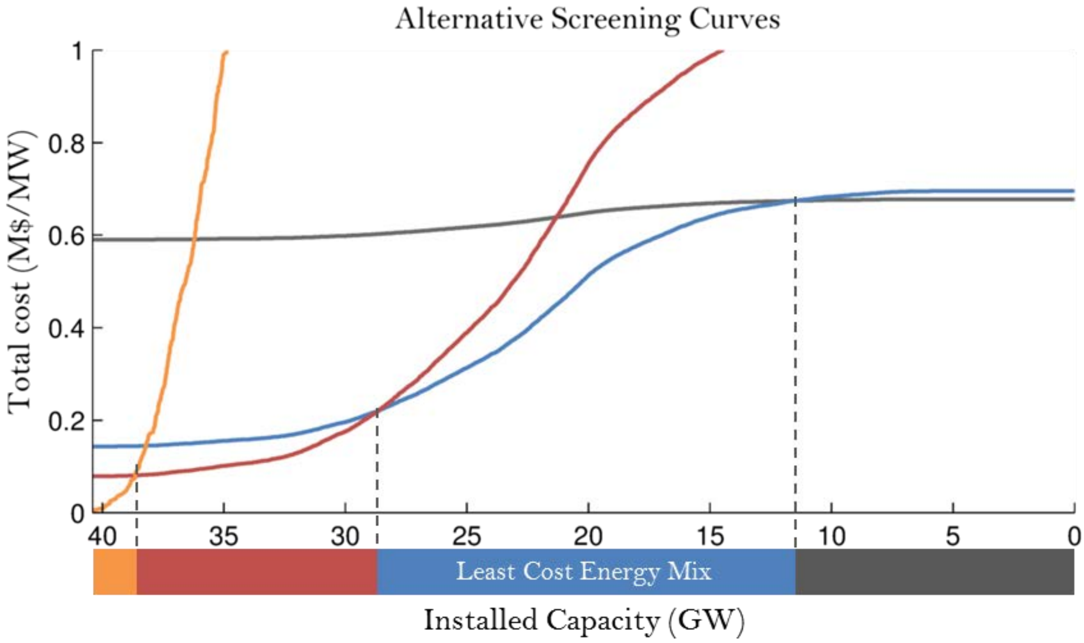

Figure 26. Alternative Screening Curves Method

We will now use this SSCC method to compare the energy mixes obtained in our model (Figure 27). Thanks to the alternative SSCC method we can directly obtain the cost of each energy mix in a graphical way.

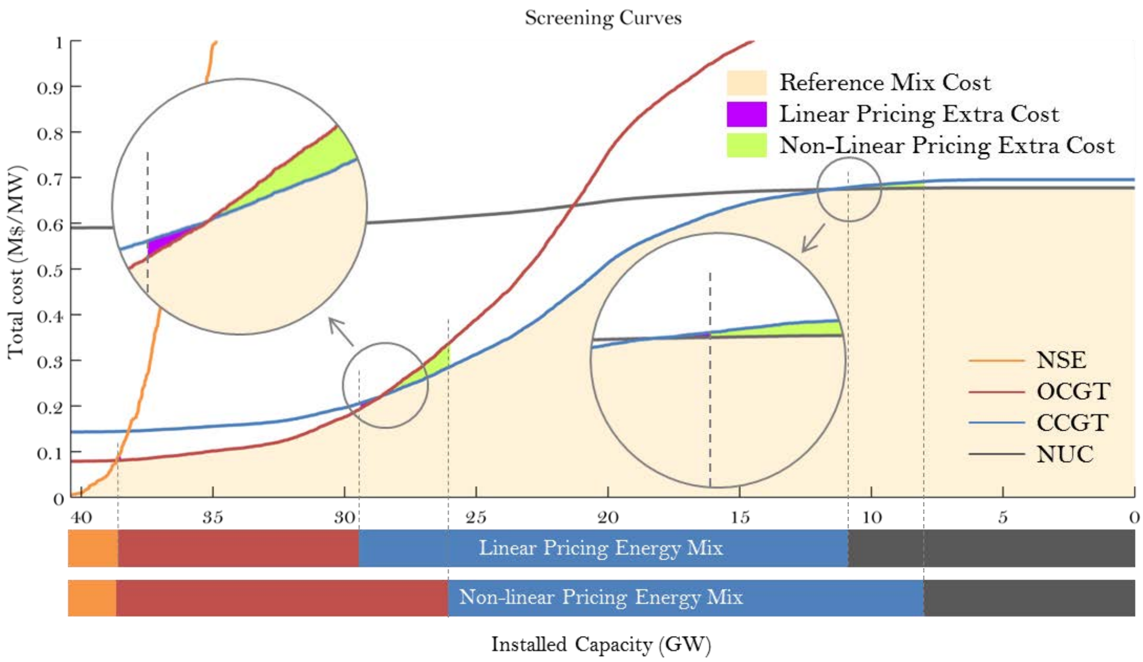

Figure 27. Screening curves representation of total costs

This figure should help to better interpret what at first might seem a counterintuitive result: the structure of the optimal mix changes significantly as a consequence of the pricing rule implemented, but the total costs are affected to a lower extent when compared in relative terms. With this representation we shall see that effectively not-so insignificant changes in the mix may not affect total costs in relative terms.

To begin with, let us graphically identify the total cost of the optimal mix obtained with the SSCC method as the solid area of the figure above. Now we shall compare the costs resulting from the mixes depicted in figure. The extra cost of the non-linear pricing mix is produced by the excess of peak-load capacity and the lack of base-load capacity. These extra costs are represented by green areas in the figure and are relatively small if compared to the total costs of the system.

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

Table ii: Total cost comparison of the resulting mixes

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

As already illustrated by the SSCC, the percentage difference with respect to the minimum cost is very small for both pricing rules so it could seem that the impact of pricing rules in total costs is negligible. Actually, we should first know what can be called a small difference in this context and what the impact of installing a sub-optimal generation mix can be. One clear reason for this difference to be small is that the cost data considered for mid-load units makes it a very competitive technology for peak-load and base-load alike and this diminishes the effect of deviations in the energy mix. Take for instance a mix in which only CCGT units are installed; this mix would produce a 3% increase in total costs with respect to the minimum cost reference mix. Considering this we can say that the non-linear pricing rule produced a relatively big increase in total costs while the linear pricing rule produced a cost increase two orders of magnitude lower.

4.5 Regulatory change impact analysis

We now compare the result of applying (changing) the pricing rule to the adapted-to-the-other-pricing-rule energy mix. We can see how the changes are relevant (Table iii). The non-linear rule does not produce sufficient remuneration for the linear mix and the linear rule produces excessive remuneration for the non-linear mix.

Table iii: Investment cost recovery under different generation mix - pricing rule combinations

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

This allows extracting two additional conclusions. First, in the previous table it is clearly illustrated that the performance of one or the other pricing rule can only be judged in the long run: it would make no sense to evaluate the suitability of the implementation of one rule on the basis of the estimated returns or costs calculated for a mix adapted to any other market design context, or even to the mix resulting from a pure cost minimization.

Second, from the regulatory design point of view, it has been evidenced that a change in the pricing rule would produce an economic imbalance requiring new investments but also divestments that could take a long time before a new economic equilibrium is reached. So, although further research would be needed, regulators should be discouraged to change the particular pricing rule in force (linear or non-linear) since the negative impact of “disadapting" the mix could be relevant, and the potential benefits in the long run are yet not clear enough.

CHAPTER 5. SENSITIVITY TO VARYING RES-E PENETRATION

The results presented in the previous chapter accomplish the first goal of the project which was to assess the impact of the pricing rule in the generation investment signals and to quantify the impact of such signals in the generation mix installed and its associated cost. The analysis was carried out for a scenario with a large deployment of RES-E under the assumption that this would exacerbate the impact of pricing rules.

This chapter pursues to confirm or deny if the penetration of RES-E actually has an impact on the previous discussion. The approach followed in this case is to re-run the model presented in this project under different RES-E penetration scenarios. In total, nine scenarios were considered, Table iv details the penetration level considered for each scenario. For each scenario the solar production profile was scaled from solar production data for Spain 2012.

Table iv: PV penetration for each scenario

Scenario	1	2	3	4	5	6	7	8	9
PV penetration (GWp)	3.2	6.4	9.6	12.8	16.0	19.2	22.4	25.6	28.8

5.1 RES-E impact on the generation mix

Figure 28 reports the generation mixes obtained for each PV penetration scenario.

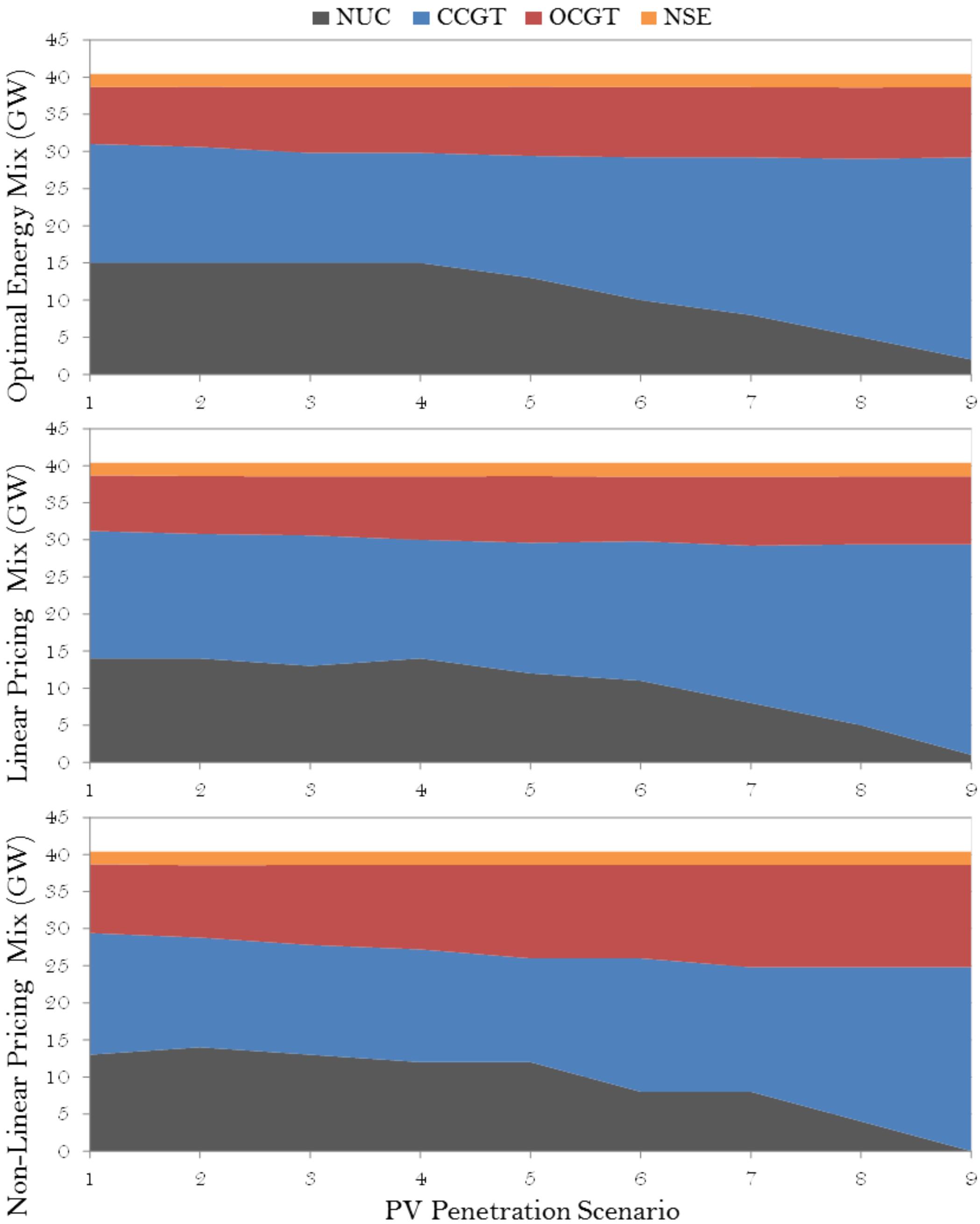

Figure 28. Comparison of generation mix under different PV penetration scenarios

The PV installed capacity is not shown in the graph since it has already being indicated in Table iv for each scenario. Only the thermal mix is shown; clearly, PV penetration does not decrease the peak capacity needed in the thermal system.

The main characteristic previously observed in a non-linear pricing mix, which was the excess of peak-load (OCGT) capacity remains present in all scenarios. At the same time, this excess of peak-load capacity is compensated with less base-load capacity as expected. To determine if the differences between peak-load and base-load capacity are affected by RES-E penetration the following figures disaggregate this information in technologies.

Figure 29 highlights the difference in nuclear capacity between the reference mix and the mixes resulting from each of the pricing rules. The effect of lumpiness, already discussed in Section 4.1, is very important in the case of nuclear capacity because of the relatively big size of this type of power plant. This lumpiness introduces a lot of noise in the information retrieved. Although the difference in capacity remains relatively constant for any RES-E penetration level, there are two important facts to be observed. First, the non-linear pricing mix never has more baseload capacity than the linear pricing mix. Second, the first four scenarios (lower RES-E penetration) all tend to the same nuclear capacity, with any difference probably being caused by lumpiness. This is because it would be economically sound to install more nuclear capacity for those low RES-E penetration scenarios but it is technologically infeasible since it was considered to be a must-run technology.

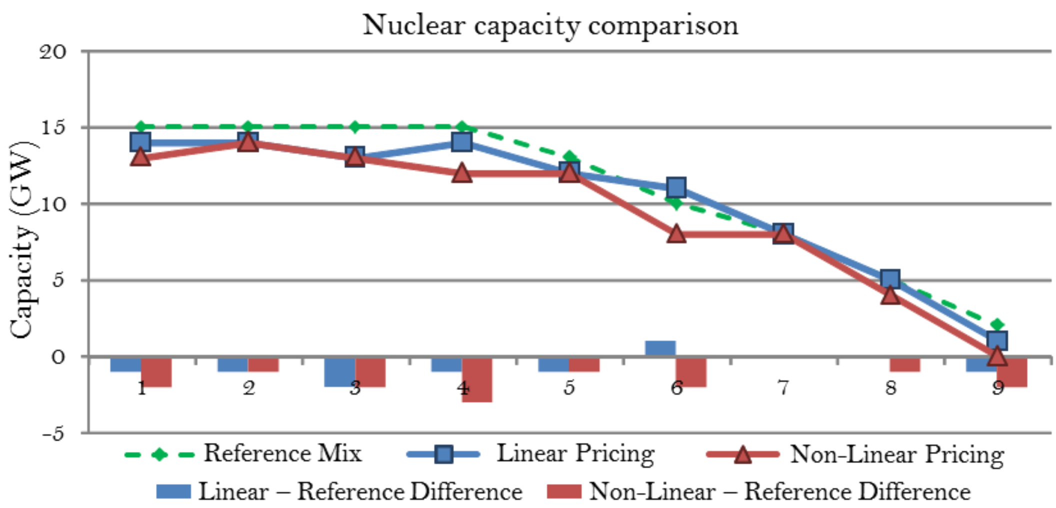

Figure 29. Evolution of nuclear capacity with increasing RES-E penetration

Figure 30 shows a clearer trend; we already know that the first four scenarios are subject to a lot of variability because of the nuclear capacity instability just exposed. For the next scenarios (5-9), we observe again that the non-linear pricing rule produces bigger differences from the reference mix. As in the case of nuclear, the impact of the non-linear pricing rule is to decrease the installed capacity of this technology. This effect is to be expected for any inframarginal technology.

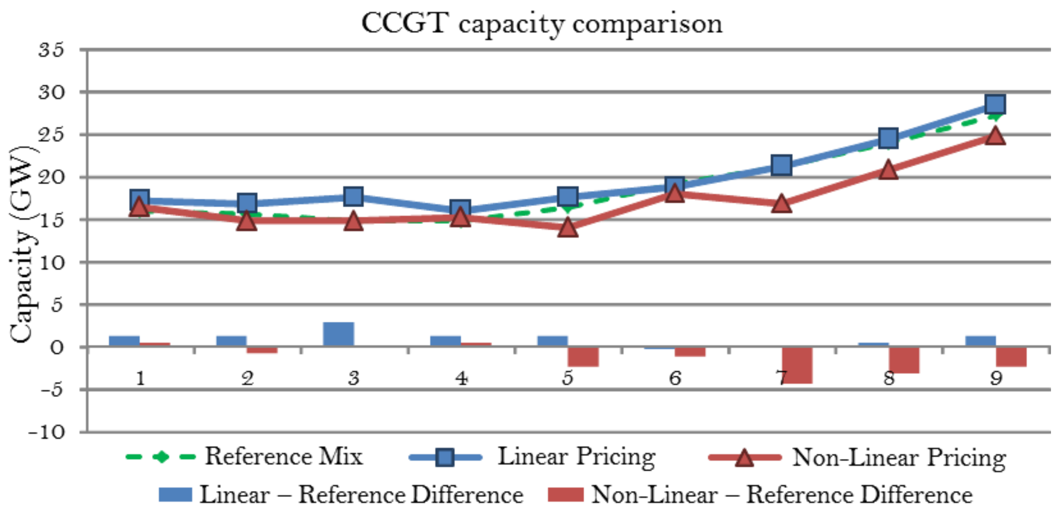

Figure 30. Evolution of CCGT capacity with increasing RES-E penetration

Finally, Figure 31 compares OCGT capacity for each pricing rule. This technology is the most affected one by the pricing rule since the effect of weaker investment signals for base-load capacity was shared by nuclear and CCGT power plants. In this case, RES-E penetration clearly increases the difference between each energy mix confirming our initial hypothesis.

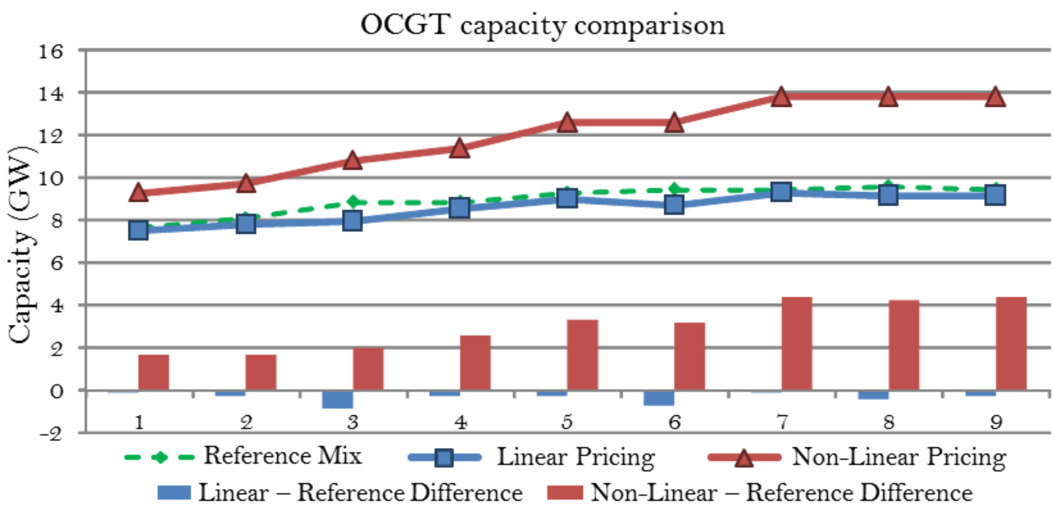

Figure 31. Evolution of OCGT capacity with increasing RES-E penetration

OCGT power plants considered in the simulation have the smallest size (150 MW); making this technology less prone to lumpiness effects. This also explains why this is the case in which a clearer trend is shown.

5.2 RES-E impact on total system cost

Figure 32 shows the evolution of total system cost for each of the energy mixes obtained under the linear pricing rule. The cost of the thermal mix decreases with an increasing share of RES-E generation but this is only because the investment and operation cost of non-thermal power plants (solar PV) is not included in this graph. Overall, total cost would only decrease up to a certain amount of RES-E penetration (assuming some cost competitiveness for solar PV). Afterwards, solar PV capacity would be excessive and total cost would rise again. This is not shown because our interest is on the cost dynamics of the adapting thermal mix.

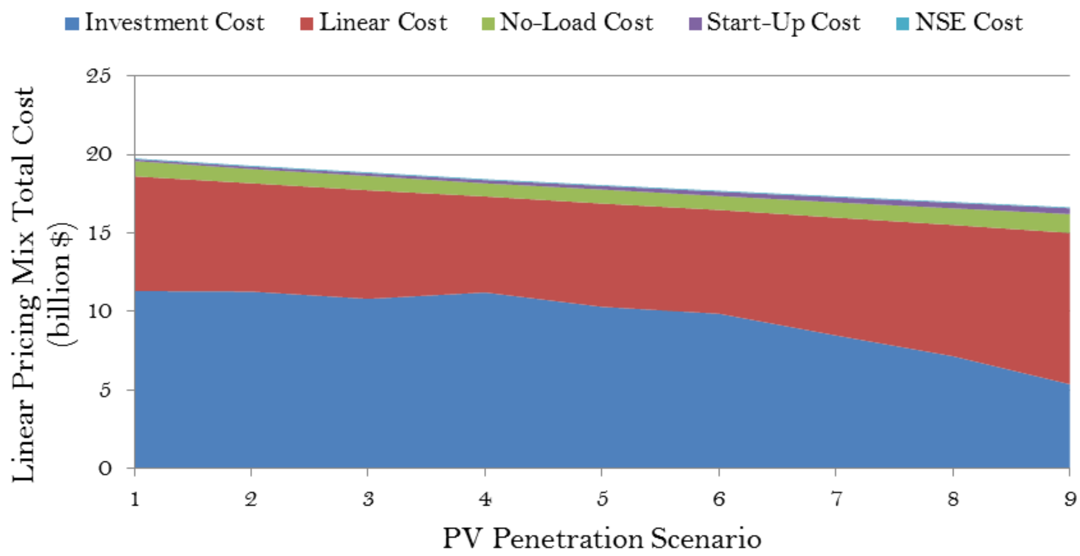

Figure 32. Evolution of total system cost for a linear pricing mix with increasing RES-E

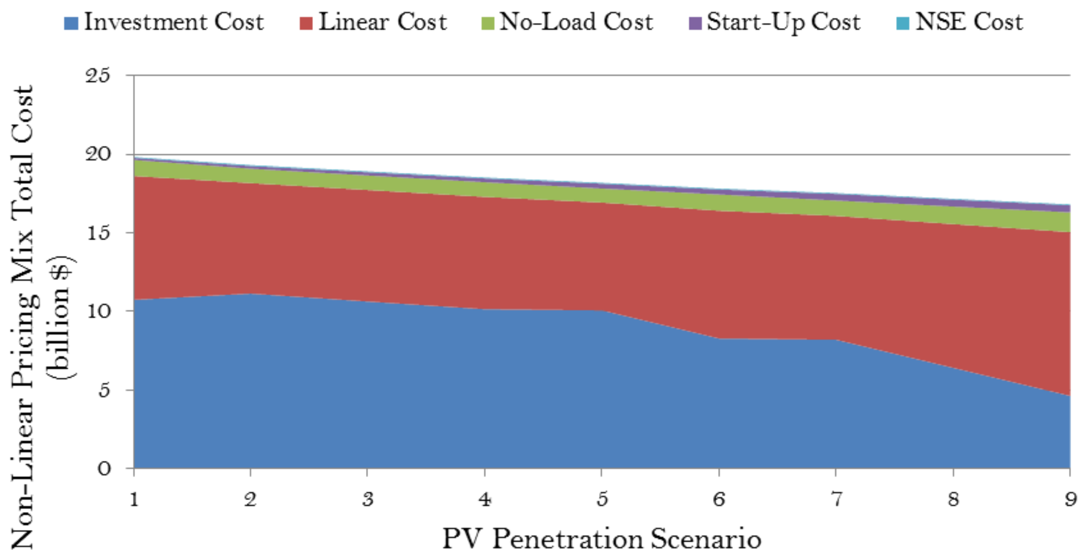

Figure 33. Evolution of total system cost for a non-linear pricing mix with increasing RES-E

Figure 33 presents the same results for the non-linear pricing mixes. Some clear consequences of the previously shown generation mixes are observed; the linear pricing rule attracted more capital intensive technologies for any amount of RES-E penetration while the non-linear pricing rule increases linear operation costs. These two components of total cost (investment and linear operation costs) represent the biggest share of total costs.

Recall from Section 4.4 that the difference between the linear pricing mix and the non-linear pricing mix is very small in relative terms. In Figure 34 the parameter represented by the solid lines is the difference between the reference mix total cost and each of the calculated mixes total cost (as in Table ii).

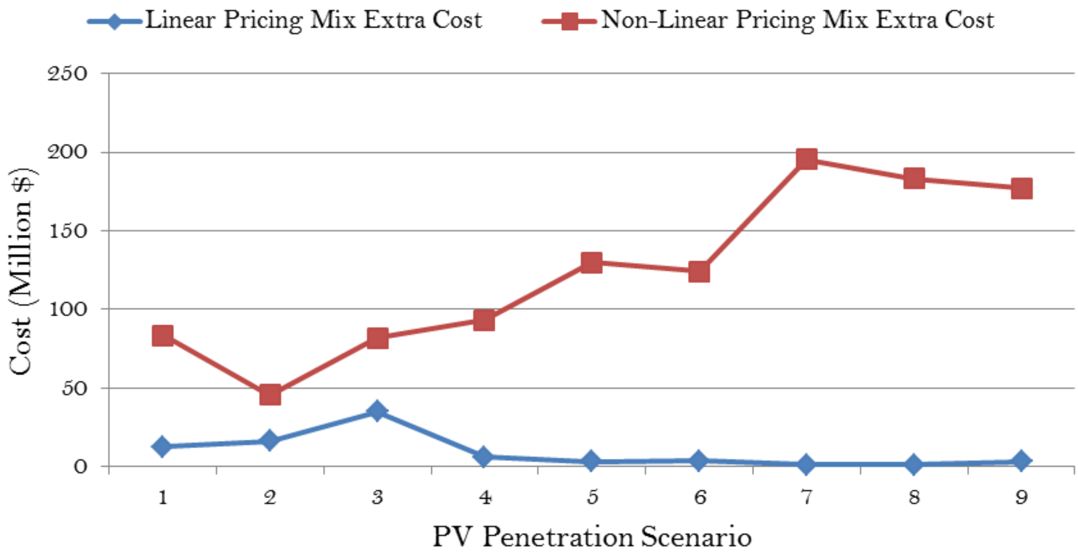

Figure 34. Total cost deviation from reference mix for each pricing rule with increasing RES-E

An important result is easily observable; the linear pricing rule produces a very small increase in total cost compared to the reference mix while the non-linear pricing rule produces a much bigger increase in total cost. This result was already observed for only one scenario of solar PV penetration in Chapter 4. However, there is a more important conclusion to extract from this figure which is that RES-E penetration does affect the difference between pricing rules in the way expected. Higher RES-E penetration levels increase the difference between linear and non-linear pricing rules.

It was pointed out previously that the main driver of this difference is ultimately the share of the cost produced by non-convex costs (start-up and no-load cost). If this is the case, non-convex costs share in total cost should be increasing under increasing levels of RES-E penetration.

Figure 35 represents both start-up costs and no-load cost for each pricing rule. No-load cost begins increasing after the fifth scenario, this is most likely due to the substituion of nuclear power plants for other technologies with higher no-load cost. Although this trend is not completely clear it seems reasonable to think that higher

RES-E penetration requieres less baseload capacity which usually has the lowest no-load cost and therefore, increases this component of total cost.

Start-up costs are directly related to RES-E penetration since the increasing solar PV production requires a higher number of star-up operations. Figure 35 crearly shows this direct relation and is consistent with the hypotesis of start-up costs being the main cause of the increasing difference between each of the pricing rules results. Furthermore, not only the share of start-up costs raises, also the difference in start-up costs between each of the mixes increases.

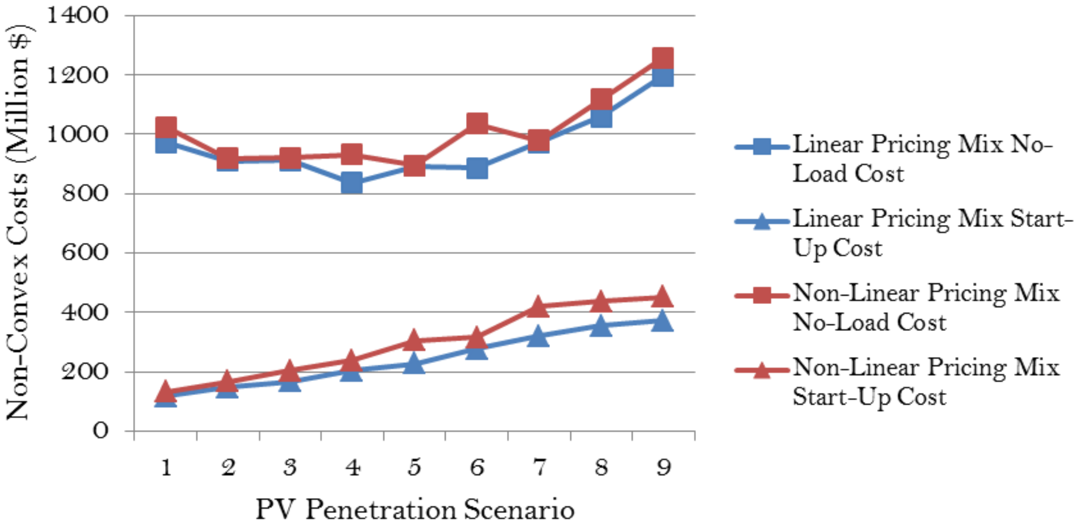

Figure 35. Non-convex costs for each pricing rule with increasing RES-E penetration

CHAPTER 6. CONCLUSIONS

This project has developed a practical and computationally efficient methodology to compare the long-term effect of pricing rules in the investment signals perceived by market agents. We asses this impact in terms of the expected energy mix to be installed under different pricing rules.

In Chapter 4 a real size example of a power system was used to compare two pricing rules; a non-linear pricing rule resembling current market practices in the US and a linear pricing rule including the main characteristics proposed in literature. Two important results can be extracted from this simulation. First, the way in which non-convex costs are reflected in the uniform price can have a significant impact in the investment signals perceived by market agents and the linear pricing rule seems to promote a more efficient energy mix. Second, contrary to what a superficial analysis may suggest and because of its higher long-term efficiency, a linear pricing rule does not necessarily produce higher energy prices than a non-linear pricing rule; in fact it can lower the price since it attracts generation technologies with lower variable costs.

In Chapter 5 the simulation was repeated for different RES-E penetration scenarios. It is concluded that RES-E penetration plays an important role in the previous discussion. Higher RES-E penetration produces bigger differences between each of the mentioned pricing rules. The results presented in this dissertation suggest that a properly designed linear pricing rule can be more efficient in the long term. But it has been evidenced that adapting a market from an existing non-linear settlement mechanism (or the other way around) could be a problematic process that requires careful planning.

6.1 Academic impact

The methodology exposed in Chapter 3 and the results presented in Chapter 4 resulted in the submission of an academic paper to the Energy Economics Journal (Herrero et al., 2014a).

The additional results obtained for Chapter 5 have been presented in the 37th International IAEE (International Association for Energy Economics) Conference in New York City, USA (Herrero et al., 2014b).

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TABLE OF APPENDIXES

Appendix A. NYISO formulation of side-payments

NYISO Accounting and Billing Manual (Manual 14), Appendix E, Section E.1

Appendix E. Bid Production Cost Guarantee Formulae

E.1. Day-Ahead Bid Production Guarantee (DAM BPCG)

$$\boldsymbol{DA\,BPCG = max\left[\sum_{h=1}^{N}\left\{\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}MGH_{gh}^{DA} + SUC_{gh}^{DA}NSUH_{gh}^{DA} - LBMP_{gh}^{DA}EH_{gh}^{DA} - NASR_{gh}^{DA}\right\}, 0\right]}$$

Where:

N: Number of hours in the Day-Ahead Market Day;

EH_{gh}^{DA}: Energy scheduled Day-Ahead to be produced by Generator *g* in hour *h* expressed in terms of MWh;

MGH_{gh}^{DA} : Energy scheduled Day-Ahead to be produced as the minimum generation segment by Generator *g* in hour *h* expressed in terms of MWh;

C_{gh}^{DA}: Incremental Energy Bid cost submitted by Generator *g*, or when applicable the mitigated Incremental Energy Bid cost curve for Generator *g*, in the Day-Ahead Market for hour *h* expressed in terms of \$/MWh;

MGC_{gh}^{DA}: Minimum Generation Bid by Generator *g*, or when applicable the mitigated Minimum Generation Bid for Generator *g*, for hour *h* in the Day-Ahead Market, expressed in terms of \$/MWh.

If Generator *g* was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation (SRE), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator *g* will have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost Guarantee until Generator *g* completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA}: Start-Up Bid by Generator *g* in hour *h*, or when applicable the mitigated Start-Up Bid for Generator *g* in hour *h*, in the Day-Ahead Market expressed in terms of \$/start; *provided, however*, that the Start-Up Bid for Generator *g* in hour *h* or, when applicable, the mitigated Start-Up Bid, for Generator *g* in hour *h*, may be subject to pro rata reduction in accordance with the rules illustrated formulaically in section E.3 below. Bases for pro rata reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator *g*'s Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator *g*'s Day-Ahead or SRE schedule.

If a Generator *g* was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, and Generator *g* has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, then Generator *g* will have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost Guarantee.

For a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the NYISO and runs in real-time, the Start-Up Bid for Generator *g* in hour *h* will be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator *g*, for the hour (as determined at the point in time in which the NYISO provided notice of the request for start-up);

$NSUH_{gh}^{DA}$: Number of times Generator *g* is scheduled Day-Ahead to start up in hour *h*;

$LBMP_{gh}^{DA}$: Day-Ahead LBMP at Generator *g*'s bus in hour *h* expressed in \$/MWh;

$NASR_{gh}^{DA}$: Net Ancillary Services revenue, expressed in terms of \$, paid to Generator *g* as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour *h* which is computed as follows:

$$\boldsymbol{NASR_{gh}^{DA} = VSS_{gh} + \left(REGCS_{gh}^{DA} - REGCB_{gh}^{DA}\right) + \left(OPResS_{gh}^{DA} - OPResB_{gh}^{DA}\right)}$$

Where:

VSS_{gh}: Voltage Support Service payments received for hour *h* by Generator *g* who is not a Supplier of Installed Capacity and has been scheduled to operate in that hour;

$REGCS_{gh}^{DA}$: Regulation Capacity payments made to Generator *g* for all Regulation Capacity scheduled Day-Ahead for hour *h*

$REGCB_{gh}^{DA}$: Generator *g*'s Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Capacity in hour *h*;

$OPResS_{gh}^{DA}$: Payments made to Generator *g* for providing Spinning Reserve and synchronized 30-Minute Reserve in hour *h* for Day-Ahead commitments to provide such reserves

$OPResB_{gh}^{DA}$: Generator *g*'s Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in hour *h*.

E.2. Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$\boldsymbol{TotMWReq_{gh} = MinOpMW_{gh} \times n_{gh}}$$

Appendix B. MISO formulation of side-payments

MISO Business Practices Manual 005 - Market Settlements, Market Settlements Calculation Guide, Appendix B, Section B.12

B.12 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount (DA_RSG_MWP)

Generation Resources and Demand Response Resources – Type II that are committed by MISO and scheduled in the Day-Ahead Energy and Operating Reserve Market are guaranteed recovery of their Start-Up, No-Load, Energy and Operating Reserve Offers, collectively referred to as production Offer. Demand Response Resources – Type I that are committed by MISO and scheduled in the Day-Ahead Energy and Operating Reserve Market are guaranteed recovery of their Shut-Down, Hourly Curtailment and Energy Offers, collectively referred to as production Offer. On an hourly basis, the DART determines whether a Resource has met the eligibility requirements to have their production Offer and Operating Reserve Offer guaranteed. The Day-Ahead settlement calculation compares whether the asset's combined Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve market value for all of the eligible hours for the Operating Day exceeds the combined value of the production Offer and Operating Reserve Offers for those same hours. The asset's value is calculated without regard to FBTs. If the total daily value is less than the total daily production Offer amount, the difference is credited to the AO as a Day-Ahead RSG MWP Amount.

Day-Ahead RSG MWP Amounts may be mitigated for Generation Resources by asset by day when production Offer and Operating Reserve Offer for the Operating Day exceed the Independent Market Monitor's (IMM's) pre-determined reference tolerances. There is no mitigation of Day-Ahead RSG MWP Amounts for Demand Response Resources – Type I and Type II. These actions prevent AOs from exercising undue influence when their Generation Resources are known to be in demand for reliability in a local area. The settlement statement displays an "IMM RSG MITIGATION" flag indicating when a particular Generation Resource asset Day-Ahead RSG MWP Amount has been mitigated. The IMM will not always provide a mitigated reference production Offer and Operating Reserve Offer. When no IMM production Offer and Operating Reserve Offer has been provided to MISO for the entire Operating Day, no IMM production Offer and Operating Reserve Offer is displayed on the Settlement Statement and the IMM mitigation comparison is not performed. An IMM RSG MITIGATION value of "N" indicates no mitigation had been performed; a value of "Y" indicates that the Day-Ahead RSG MWP was mitigated for the Operating Day.

Day-Ahead RSG MWP Amounts may also be mitigated for Generation Resources by asset by day for Voltage and Local Reliability Commitment (VLRC) requirements. Mitigation may be warranted when any of the following values exceed the Independent Market Monitor's (IMM's) pre-determined reference tolerances:

- Generation Offers
- Economic Minimum
- Minimum Run Time

The IMM RSG MITIGATION value of "V" is displayed on the settlement statement when a particular Generation Resource asset Day-Ahead RSG MWP Amount has been mitigated for Voltage and Local Reliability Commitment requirements. The IMM will not always provide mitigated VLRC Generation Offer, Economic Minimum, and/or Minimum Run Time values. When no IMM VLRC Generation Offer, Economic Minimum, and/or Minimum Run Time values have been provided to MISO for the entire Operating Day, no IMM values are displayed on the Settlement Statement and the IMM mitigation comparison is not performed.

Day-Ahead RSG MWP Amount, including determinants, is displayed on the Day-Ahead Energy and Operating Reserve Market Settlement Statement.

An asterisk (*) denotes a billing determinant that is displayed on an AO's Day-Ahead statement.

A caret (^) symbol represents the result is rounded based on MISO Market Settlements rounding methodology in the Market Settlements BPM.

B.12.1 Calculation Inputs for DA_RSG_MWP

*IMM_MIT_MWP_TOL_AMT	IMM Mitigated MWP Tolerance Amount ($/MWh); the IMM provided fixed dollar per Megawatt Hour tolerance is used to determine if a Generation Resource asset's daily production Offer is excessive.
*DA_RSG_PC	Day-Ahead RSG Production Cost (Offer) Amount ($); hourly production Offer calculated by DART that includes Start-Up, No-Load, Energy and Operating Reserve Offer for a Generation Resource and Demand Response Resource – Type II or Shut-Down, Hourly Curtailment and Energy Offer for a Demand Response Resource – Type I. DART averages the awarded production Offer across all eligible hours of the Operating Day. Eligible periods spanning midnight have the Start-Up (Shut-Down) value averaged across the prior day to midnight period only. DART determines each Resource's eligibility for full or partial Start-Up (Shut-Down) Offer based upon any previous status including whether it is a hot, intermediate or cold start condition. The total hourly eligible production cost value is calculated by DART for each Resource and provided to Market Settlements. Production Offers are shown as positive

	values. Day-Ahead production Offers only display on statements when values have been provided by the DART. In the absence of any displayed values, the participant can assume they are zero for every Hour.
*DA_RSG_MIT_PC	Day-Ahead Mitigated RSG Production Cost (Offer) Amount ($); hourly mitigated Start-Up cost, No-Load costs, Energy Offer and Operating Reserve cost amount provided by the IMM for a Generation Resource. Mitigated Production Costs are shown as positive values. Day-Ahead IMM Production Costs only display on statements when values have been provided by the DART or the IMM System. In the absence of any displayed values, the participant can assume they are zero for every Hour.
*DA_RSG_ELIGIBILITY	(Hourly) Day-Ahead RSG Eligibility (flag); an hourly flag that indicates whether an asset is eligible to receive their Production Costs for the Hour. The eligibility is determined by DART when the Day-Ahead Energy and Operating Reserve Market is cleared. A "Y" indicates the asset is eligible for the Hour and an "N" indicates the asset is not eligible for the Hour. Day-Ahead RSG eligibility status only displays on statements when Production Cost values have been provided by DART or the IMM System. In the absence of any displayed values, the participant assumes the unit eligibility is "N". The DA_RSG_ELIGIBILITY is set to "Y" whenever the asset has been guaranteed to receive their production costs.
*DA_SCHD_{Gen}	Hourly Day-Ahead Asset Schedule Volume for a Resource asset (MWh); the Day-Ahead Asset Schedule Volume for a Resource asset is the market cleared Day-Ahead Asset schedule. Only Resource schedules are considered in this charge type. A positive schedule represents a Load obligation and a negative schedule represents a Resource obligation.
*DA_IMM_RSG_MWH	Hourly Day-Ahead Asset Mitigated Volume for a Resource asset (MWh); hourly mitigated Economic Minimum volume provided by the IMM for a Generation Resource. Day-Ahead IMM RSG MWH values are only displayed on statements when the values have been provided by the IMM. In the absence of any displayed values, the participant can assume they are zero for every Hour.

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*DA_LMP_EN	Hourly Day-Ahead LMP ($/MWh); at a Commercial Pricing Node. The Day-Ahead Energy and Operating Reserve Market clearing price for Energy at a given Commercial Pricing Node in the Transmission Provider Region, which is equivalent to the marginal cost of serving demand at the Commercial Pricing Node. The Day-Ahead Locational Margin Price includes the MCC and the MLC.
*DA_REG_VOL	Hourly Day-Ahead Cleared Regulation Volume (MWh); the amount of Regulating Reserve cleared in the Day-Ahead Energy and Operating Reserve Market by a qualified Resource.
*DA_REG_MCP	Hourly Day-Ahead Regulation Market Clearing Price ($/MWh); the hourly Regulating Reserve Market Clearing Price at a Commercial Pricing Node.
*DA_SPIN_VOL	Hourly Day-Ahead Cleared Spinning Reserve Volume (MWh); the amount of Spinning Reserve cleared in the Day-Ahead Energy and Operating Reserve Market by a qualified Resource.
*DA_SPIN_MCP	Hourly Day-Ahead Spinning Reserve Market Clearing Price ($/MWh); the hourly Spinning Reserve Market Clearing Price at a Commercial Pricing Node.
*DA_SUPP_VOL	Hourly Day-Ahead Cleared Supplemental Reserve Volume (MWh); the amount of Supplemental Reserve cleared in the Day-Ahead Energy and Operating Reserve Market by a qualified Resource.
*DA_SUPP_MCP	Hourly Day-Ahead Supplemental Reserve Market Clearing Price ($/MWh); the hourly Supplemental Reserve Market Clearing Price at a Commercial Pricing Node.

B.12.2Intermediate Calculations for DA_RSG_MWP

IF	The "IF" logical statement is a conditional test that returns one value if a condition you specify evaluates to TRUE and another value if it evaluates to FALSE. { An example of the IF (logical_test, THEN value_if_true, ELSE value_if_false) }
DA_IMM_RSG_MWH_TOTAL	Daily Day-Ahead Asset Mitigated Volume for a Resource asset (MWh); the hourly summation of Day-Ahead Asset Mitigated Volume for a Resource. $= \Sigma_H$ (DA_IMM_RSG_MWH)

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DA_RSG_EN_VAL	Hourly Day-Ahead Revenue Sufficiency Market Energy Amount ($); this amount represents the hourly cleared Day-Ahead asset schedule energy value of an asset when it is committed by MISO combined with the revenue obtained for Operating Reserve clearing volume in the Day-Ahead Energy and Operating Reserve Market. The calculation is performed for every Hour where the DART has determined the asset has met the eligibility requirement for the Hour. The value is calculated by multiplying the cleared asset energy schedule by the LMP at the Commercial Pricing Node without regard for FBTs and then adding the Operating Reserve revenue. = IF { DA_IMM_RSG_MWH > 0, THEN [(MIN ((DA_IMM_RSG_MWH * (-1)), 0) * DA_LMP_EN) + (((DA_REG_VOL * DA_REG_MCP) + (DA_SPIN_VOL * DA_SPIN_MCP) + (DA_SUPP_VOL * DA_SUPP_MCP)) * (-1))], ELSE IF (DA_IMM_RSG_MWH_TOTAL = 0 AND DA_RSG_ELIGIBILITY = "Y"), THEN [(MIN (DA_SCHD$_{GEN}$, 0) * DA_LMP_EN) + (((DA_REG_VOL * DA_REG_MCP) + (DA_SPIN_VOL * DA_SPIN_MCP) + (DA_SUPP_VOL * DA_SUPP_MCP)) * (-1))], ELSE 0 }
DA_RSG_EN_VAL_TOTAL	Daily Day-Ahead Revenue Sufficiency Market Energy Amount for a Resource asset ($); the daily summation of hourly Day-Ahead Revenue Sufficiency Market Energy Amount. = Σ$_H$ (DA_RSG_EN_VAL)
DA_SCHD_TOTAL	Daily Day-Ahead Asset Schedule Volume for a Resource asset (MWh). = Σ$_H$ IF { DA_RSG_ELIGIBILITY = "Y", THEN [(MIN (DA_SCHD$_{GEN}$, 0) * (-1))], ELSE 0 }
DA_PC_AMT	Hourly Day-Ahead RSG Production Cost Amount for a Resource asset ($); the hourly Day-Ahead RSG Production Cost credit amount. = IF { DA_RSG_ELIGIBILITY = "Y", THEN [(DA_RSG_PC) * (-1)], ELSE 0 }

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DA_PC_AMT_MIT	Hourly Day-Ahead Mitigated RSG Production Cost Amount for a Generation Resource asset ($); the hourly Day-Ahead Mitigated RSG Production Cost credit amount for a Generation Resource. = IF { DA_IMM_RSG_MWH > 0 THEN [(DA_RSG_MIT_PC) * (-1)], ELSE IF (DA_IMM_RSG_MWH_TOTAL = 0 AND DA_RSG_ELIGIBILITY = "Y"), THEN [(DA_RSG_MIT_PC) * (-1)], ELSE 0 }
DA_PC_AMT_TOTAL	Daily Day-Ahead RSG Production Cost Amount ($); the daily summation of the Hourly Day-Ahead RSG Production Cost Amount. = Σ$_H$ (DA_PC_AMT)
DA_PC_AMT_MIT_TOTAL	Daily Day-Ahead Mitigated RSG Production Cost Amount ($); the daily summation of the Hourly Day-Ahead Mitigated RSG Production Cost Amount for a Generation Resource. = Σ$_H$ (DA_PC_AMT_MIT)
DA_MWP_AMT	Daily Day-Ahead RSG MWP Amount ($); represents the daily amount of Production Costs not covered by the Asset's energy value. = MIN [0, (DA_PC_AMT_TOTAL - DA_RSG_EN_VAL_TOTAL)]
DA_MWP_MIT_AMT	Daily Day-Ahead RSG Mitigated MWP Amount ($); represents the daily amount of the IMM calculated Production Costs not covered by the Generation Resource asset's energy value. = MIN [0, (DA_PC_AMT_MIT_TOTAL - DA_RSG_EN_VAL_TOTAL)]
DA_IMM_TOL	Day-Ahead IMM Tolerance ($); represents the IMM's tolerance value whereby if the Generation Resource asset's Dollar per MWh difference between the daily Day-Ahead Revenue Sufficiency MWP Amount and the daily Mitigated Day-Ahead Revenue Sufficiency MWP Amount exceeds the IMM Mitigated MWP Tolerance Amount, then the asset's make whole credit amount is reduced to the Day-Ahead RSG MWP Mitigated amount. = MAX (DA_MWP_AMT - DA_MWP_MIT_AMT , 0) / DA_SCHD_TOTAL

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*IMM(DA)_RSG_MITIGATION	Daily Day-Ahead IMM RSG Mitigation flag (Y, N, or V); a daily flag indicating whether a Generation Resource asset's Day-Ahead revenue sufficiency MWP had been mitigated by the IMM. An IMM RSG MITIGATION value of "N" indicates no mitigation had been performed; a value of "Y" indicates that the Day-Ahead RSG MWP was mitigated for the Operating Day for the generation asset; a value of "V" indicates that the Day-Ahead RSG MWP was mitigated for Voltage and Local Reliability for the Operating Day for the generation asset. = IF (DA_IMM_RSG_MWH_TOTAL > 0 , THEN "V" , ELSE IF DA_IMM_TOL >= IMM_MIT_MWP_TOL_AMT , THEN "Y" , ELSE "N")
DA_RSG_ELIG_HRS	Day-Ahead RSG Eligibility Hour Count by asset (Integer); this integer represents the total number of hours during an Operating Day where the related asset is eligible to receive the Day-Ahead RSG MWP. = $\Sigma_{Hr\text{-}Asset}$ [IF (DA_IMM_RSG_MWH > 0) , THEN 1 , ELSE IF (DA_IMM_RSG_MWH_TOTAL = 0 AND DA_RSG_ELIGIBILITY = "Y") , THEN 1 , ELSE 0]
*^DA_ASOF_MWP	Hourly Day-Ahead As Offered MWP ($); the hourly credit the participant will receive if they are not mitigated by the IMM. Note this credit amount is displayed as a positive amount and represents the amount in dollars per Hour MISO will pay the participant if not mitigated. Each Hour is rounded to the nearest cent with any rounding error being carried forward to the next hour of the day. Rounding error does not carry from one Operating Day to another. = IF [DA_RSG_ELIGIBILITY = "Y" , THEN (DA_MWP_AMT / DA_RSG_ELIG_HRS) * (-1), ELSE 0]
*^DA_IMM_MWP	Hourly Day-Ahead As Offered MWP ($); the hourly credit the participant will receive if they are mitigated by the IMM. Note this credit amount is displayed as a positive amount and represents the amount in dollars per Hour MISO will pay the participant if mitigated. Each Hour is rounded to the nearest cent with any rounding error being carried forward to the next hour of the day. Rounding error does not carry from one Operating Day to another.

	= IF [DA_IMM_RSG_MWH > 0 , THEN (DA_MWP_MIT_AMT / DA_RSG_ELIG_HRS) * (-1) , ELSE IF (DA_IMM_RSG_MWH_TOTAL = 0 AND DA_RSG_ELIGIBILITY = "Y") , THEN (DA_MWP_MIT_AMT / DA_RSG_ELIG_HRS) * (-1), ELSE 0]
DA_RSG_ASSET_CR_HR	Hourly Daily Day-Ahead RSG Credit Amount for a Generation Resource asset ($); the following equation determines whether the participant receives their MWP based on their offered data or they receive the IMM's MWP based on the IMM's mitigated Offer data. The evaluation to determine if an asset is mitigated is performed by the Operating Day, but the hourly credits may differ based on when a unit is committed, how long it takes to start up, and the cleared LMP in the market. MWPs are only provided in hours where the asset has a Day-Ahead RSG Eligibility of yes ("Y"). = IF [IMM_RSG_MITIGATION = "N" , THEN DA_ASOF_MWP * (-1) , ELSE DA_IMM_MWP * (-1)]

B.12.3Charge Type Calculation for DA_RSG_MWP

*DA_RSG_MWP_HR	Hourly Day-Ahead RSG MWP Amount ($); is the hourly AO total credit amount for all their assets. The formula result is per Hour. The hourly values are displayed beneath the Charge Type total in the Line Item section of the statement. = Σ_{Assets} (DA_RSG_ASSET_CR_HR) for Generation Resources + Σ_{Assets} [DA_ASOF_MWP * (-1)] for Demand Response Resources – Type I and Type II
*DA_RSG_MWP	Day-Ahead RSG MWP Amount ($); is the hourly asset credit amount summed for all hours of the day for an AO. = Σ_H (DA_RSG_MWP_HR)

B.13 Day-Ahead Virtual Energy Amount (DA_VIRT_EN)

The Day-Ahead Virtual Energy Amount represents an AO's total Day-Ahead net energy cost (or credit) associated with all its struck virtual Bids and Offers. The Day-Ahead Virtual Amount is calculated hourly for each AO by Commercial Pricing Node and is summed to determine a daily total. The hourly amount by Commercial Pricing Node is the net Day-Ahead Struck Virtual Bid and Offer volume multiplied by the associated LMP for the Commercial Pricing Node.

Appendix C. ISO-NE formulation of side-payments

ISO-NE Transmission, Markets and Services Tariff, Section III - Market Rule 1, Appendix F, Section III.F.2.1.1 - III.F.2.5

III.F.2.1.1 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

III.F.2.1.2 Hourly Day-Ahead Offer Amount.

The ISO calculates the generating Resource's hourly Day-Ahead offer amount based on its Day-Ahead Offer Data that was utilized by the ISO in making the initial commitment decision and the generating Resource's cleared Day-Ahead MWh for that hour.

For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

(a) The ISO accounting process applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Resource Offer Data and if the Start-Up Fee is applicable for the MWh and status of the Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource Day-Ahead and the ISO subsequently schedules this generating

Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant. The Start-Up Fee will be associated with the first hour of the Resource's minimum run time on the day for which the Resource is committed. The Start-Up Fee will always be on the same Operating Day for both the Day-Ahead and Real-Time Energy Markets for purposes of calculating Real-Time NCPC Charges/Credits.

(b) Day-Ahead NCPC Credit calculations reflect the Start-Up Fee for the appropriate hot, intermediate, or cold state of the generating unit as it was scheduled in the Day-Ahead Energy Market.

III.F.2.1.3 Hourly Day-Ahead Value.

The ISO *calculates* the generating Resource's hourly Day-Ahead value as: generating Resource cleared Day-Ahead MWh * Day-Ahead LMP

III.F.2.1.4 Daily Day-Ahead Credit.

The ISO calculates the daily Day-Ahead credit for each generating Resource as follows:

(a) Sum hourly Day-Ahead offer amounts, including applicable No-Load Fees and Start-Up Fees, for the day.

(b) Sum hourly Day-Ahead values for the day.

(c) Day-Ahead credit equals any portion of the generating Resource's total Day-Ahead offer amount in excess of its total Day-Ahead value.

III.F.2.1.5 Day-Ahead Credit Allocation.

The ISO allocates the Day-Ahead credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource was scheduled and was eligible for NCPC Credit pro-rata based on Day-Ahead Load Obligations as follows:

Hourly Credit = Daily Credit * (Day-Ahead Load Obligations in scheduled hour) / (Total Day-Ahead Load Obligations in all scheduled hours))

[Note: Each credit is allocated back retaining its flag (Local Second Contingency Protection Resource, VAR etc.)]

Appendix D. Ireland ISO formulation of linear prices

Excerpts from SEM Trading and Settlement Code, Appendix N

Operation of the MSP Software

N.16 For each Trading Period h of the Trading Day, the MSP Software shall be used to calculate System Marginal Price (SMPh), and the Market Schedule Quantity (MSQuh) for each Price Maker Generator Unit u that is not Under Test, as follows:

Step 1

Determine the Unit Commitment Schedule for each Price Maker Generator Unit that is not Under Test, including for each Pumped Storage Unit whether or not it is scheduled to pump or generate, in each Trading Period in the Optimisation Time Horizon;

Step 2

Taking the Unit Commitment Schedule as an input and therefore treating Start Up Costs, Shut Down Costs and No Load Costs as invariant, determine the Shadow Price (SPh) values and the Market Schedule Quantity (MSQuh) values for each Price Maker Generator Unit u that is not Under Test, for each Trading Period h in the Optimisation Time Horizon;

Step 3

Calculate the Uplift (UPLIFTh) element of System Marginal Price for each Trading Period h in the Trading Day of the Optimisation Time Horizon, as set out in paragraphs N.64 to N.77 below; and

Step 4

Calculate System Marginal Price (SMPh) for each Trading Period h in the Trading Day of the Optimisation Time Horizon as follows:

$$SMPh = Max\{PFLOOR, Min\{PCAP, SPh + UPLIFTh\}\}$$

Where:

1. SPh is the Shadow Price for Trading Period h
2. UPLIFTh is the Uplift for Trading Period h
3. PFLOOR is the Market Price Floor
4. PCAP is the Market Price Cap
5. Max{a,b} means the greater of the values of a and b
6. Min{a,b} means the lesser of the values of a and b

Procedure to calculate final Uplift values

N.77 For each Optimisation Time Horizon, the final part of the procedure to calculate the Uplift values (UPLIFTh) for the Trading Day t in that Optimisation Time Horizon is set out below where, within this procedure, the following meanings apply:

7. UPLIFTh is the value of Uplift for Trading Period h
8. REVMINt is the Minimum Revenue in Trading Day t, calculated in accordance with Step 2 of paragraph N.76

9. SPh is the Shadow Price for Trading Period h
10. MSQuh is the Market Schedule Quantity for Generator Unit u in Trading Period h
11. TPD is the Trading Period Duration
12. CRukt is the Cost of Running for Generator Unit u in that part of Contiguous Operation Period k which falls in the Trading Day t of the relevant Optimisation Time Horizon, calculated as set out in paragraph N.75
13. α is the Uplift Alpha value used in the determination of Uplift to determine the importance of the Uplift Cost Objective referenced in paragraph 4.68;
14. β is the Uplift Beta value used in the determination of Uplift to determine the importance the Uplift Profile Objective referenced in paragraph 4.68;
15. δ is the Uplift Delta value used in the determination of Uplift to restrict the overall increase in market revenue due to Uplift over the Trading Day t
16. $\sum_{u*}$ is a summation over all relevant Price Maker Generator Units u, (excluding Pumped Storage Units, Interconnector Units and Generator Units Under Test)
17. $\sum_{hint}$ is a summation over each Trading Period h in Trading Day t
18. $\sum_{hink \cap hint}$ is a summation over each Trading Period h that is both within Contiguous Operation Period k and within Trading Day t

The procedure is as follows:

Select a set of values of Uplift (UPLIFTh) for each Trading Period h in Trading Day t which give the minimum value of

$$\alpha \times \left[\sum_{hint} \left((UPLIFTh + SPh) \times \sum_{u*} (MSQuh \times TPD) \right) \right] + \beta \times \left[\sum_{hint} (UPLIFTh)^2 \right]$$

subject to that set of values of UPLIFTh satisfying the following constraints:

1. $\sum_{hink \cap hint} \left[(UPLIFTh + SPh) \times MSQuh \times TPD \right] \geq CRukt$ for each Price Maker Generator Unit u (excluding Pumped Storage Units, Interconnector Units and Generator Units Under Test)
2. $UPLIFTh \geq 0$ for all Trading Periods h in Trading Day t; and

$$\sum_{u*} \sum_{hint} \left((UPLIFTh + SPh) \times MSQuh \times TPD \right) \leq (1 + \delta) \times REVMINt$$

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ELECTRICITY MARKET-CLEARING PRICES AND INVESTMENT INCENTIVES: THE ROLE OF PRICING RULES

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Abstract

Pricing rules in wholesale electricity markets are usually classified around two major groups, namely linear (aka non-discriminatory) and non-linear (aka discriminatory). As well known, the major difference lies on the way non-convex costs are considered in the computation of market prices.

According to the classical marginal pricing theories, the resulting market prices are supposed to serve as the key signals around which capacity expansion revolve. Thus, the implementation of one or the other pricing rule can have a different effect on the investment incentives perceived by generation technologies, affecting the long-term efficiency of the whole market scheme.

The objective of this paper is to assess to what extent long-term investments incentives can be affected by the pricing rule implemented. To do so, we propose a long-term capacity expansion model where investment decisions are taken based on the market remuneration. We use the model to determine the optimal mix in a real-size thermal system with high penetration of renewable energy sources (since its intermittency enhances the relevance of non-convex costs), when alternatively considering the aforementioned pricing schemes.

1 INTRODUCTION

Wholesale electricity markets restructuring has been constant since the original liberalization processes of electric power sectors started back in early eighties in Chile. Yet, the unavoidable complexities of electricity generation have led to many different market designs and many associated regulatory questions (many of which remain open). In general, each design includes various markets to represent different timescales in which energy and ancillary services are traded (Batlle, 2013). This sequence of markets could be classified into long-term markets, day-ahead markets (DAM) and intraday plus balancing markets (in the EU) or real-time markets (in the US).

The core of wholesale markets is commonly the DAM, whose purpose is to match generators' offers and consumers' bids to determine electricity prices for each time interval of the following day. However, this can be achieved in a number of different ways and, as mentioned, DAMs evolved very differently in each system. An essential difference lies in the way generators can submit their offers. As explained in detail in Batlle (2013), in the majority of European Power Exchanges, market clearing is built upon simple bids (i.e. generators submit quantity-price pairs per time interval). Although some additional semi-complex conditions can be added to the bids (as for instance block bids linking bids in consecutive time intervals), this approach does not reflect either the real generation cost structure (e.g. the start-up costs) or many of the plants operation constraints (e.g. the start-up trajectory). These features can be explicitly declared in the markets run by US ISOs, where generation agents submit offers representing the parameters and costs that define their generating units' characteristics.

In principle, auctions based on simple bids have the advantage of applying a more straightforward and transparent clearing process to compute prices, but this is obtained at the expense of the efficiency of the economic dispatch[1]. In contrast, complex auctions resort to a traditional centralised unit commitment

[1] However, while it is true that the schedule resulting from the clearing of the simple bids in the DAM is often not close to the one that in principle would result from solving a unit commitment problem with perfect information, intraday markets provide market agents with an opportunity to partly correct these potential inefficiencies.

(UC) algorithm (security constrained economic dispatch optimization), with the only difference from the traditional UC problem solved in the non-liberalized context being that the data considered are market agents' bids instead of costs. The downside of complex auctions is that finding a way to compute short-term prices has no obvious solution.

In a complex auction, a uniform[2] price computed as the marginal cost of the economic dispatch solution cannot guarantee total production cost recovery for all generation agents. The marginal cost reflects the variable costs components of the offers but not the non-convex costs (start-up, no-load cost). This led to different approaches to calculate market-clearing prices that can sufficiently compensate generators for their non-convex costs; these approaches can be classified into two large groups: non-linear and linear pricing rules.

Non-linear pricing rules (also known as discriminatory) obtain a uniform marginal price (marginal cost) from the unit commitment model and, on top of it, additional side-payments are provided on a differentiated per generation unit basis. Side-payments account for the non-convex costs that the generation units could not recover solely through uniform prices[3].

On the other hand, linear pricing rules (or non-discriminatory) produce a uniform price that includes in it the effect of non-convex costs such. In the short term, the most important reason given in favour of linear pricing rules are based on efficiency implications. In particular, linear prices should bring generators' short-term offers closer to their real costs. See for example Hogan and Ring (2003) for further details.

Both of these two pricing approaches support the optimal short-term operation of DAMs but prices also have to serve as the key signal for new investments. Prices do not only compensate for operations costs, in the long run, prices resulting from a well-designed and well-functioning market should allow generators to recover the investment costs. For all inframarginal units, the difference between market prices and their operation costs should be considered a payment to finance their capital costs. Given that the uniform price perceived by all units differs from one pricing rule to the other, so does the remuneration aimed at compensating investment costs and therefore, different investment decisions should in principle be expected under each pricing rule. This long-term consideration should help to discern which of the pricing approaches is more appropriate (Vázquez, 2003). Nonetheless, it has been profusely pointed out by some of the most reputed academic experts in the field that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003), (Ring, 1995).

This paper further analyses the long-term impact of different pricing rules in an energy mix if investment is driven by short-term market prices. In particular, we follow the evidence presented by Vázquez (2003) who compared various pricing rules and stated the following: "Although, when exclusively studying operation decisions, it seems that only variable costs need to be considered (in the price formation); when the impact of the price on investment decisions is considered it is observed that it also has to partially include non-convex operation costs. When including in the price the corresponding part of start-up and no-load cost of the marginal unit, a larger remuneration is given to inframarginal units. These inframarginal units will find a greater long-term incentive to invest, and as a consequence will partially substitute the marginal technology."

Moreover, intermittent renewable energy sources (RES-E) which are expected to reach larger penetration levels in the next decades, can make this discussion more relevant. We build on the foundations of Veiga et al. (2013), who already exposed how RES-E penetration increases conventional thermal plants cycling -augmenting the share of non-convex costs (mainly start-up costs) in total operation costs- and therefore increases the differences in remuneration perceived under each of the

[2] "Uniform" indicates that all generating agents are compensated using the same price regardless of their offer.

[3] Note that side-payments resemble a "pay-as-bid" system for non-convex costs, bringing along all its inefficiency issues (Baldick et al., 2005).

pricing rules, especially for the case of base-load plants. This article, in the light of the increasing share of RES-E in generation mixes, considers a system with a large deployment of intermittent generation and analyses the impact of pricing rules on investments through the application of a very detailed capacity expansion optimization model.

The paper is organized as follows. The general methodology is described in Section 2. A brief revision of necessary background and a mathematical formulation are included in Section 3 in order to complement the description of the method and to detail some calculations. Section 4 presents the results obtained, which are discussed in Section 5, and Section 6 summarizes the outcomes of this research.

2 MATERIAL AND METHODS

The approach developed in this paper aims at calculating the perfectly adapted generation mix to be installed in a market context under different pricing rules. We base our analysis on a very detailed long-term greenfield capacity expansion optimization of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints are considered in the simulation (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.). These three technologies are chosen to represent base-load, mid-load, and peak-load plants. The mix is optimized to supply the chronological hourly demand of Spain for 2012 (assumed to be perfectly inelastic). This mix includes a fixed level of RES-E penetration assuming its remuneration is not provided by the DAM but through some additional payment mechanism. The effect of renewable energy sources is represented by means of a high penetration of solar photovoltaic (PV). The exogenous PV production profile has been scaled from the 2012 hourly production profile in Spain and in the short-term simulation the PV power output can be curtailed when needed for optimized operation.

Figure 1 aims at illustrating the different stages of the implemented methodology, while the following sections detail the operation of each element of the model.

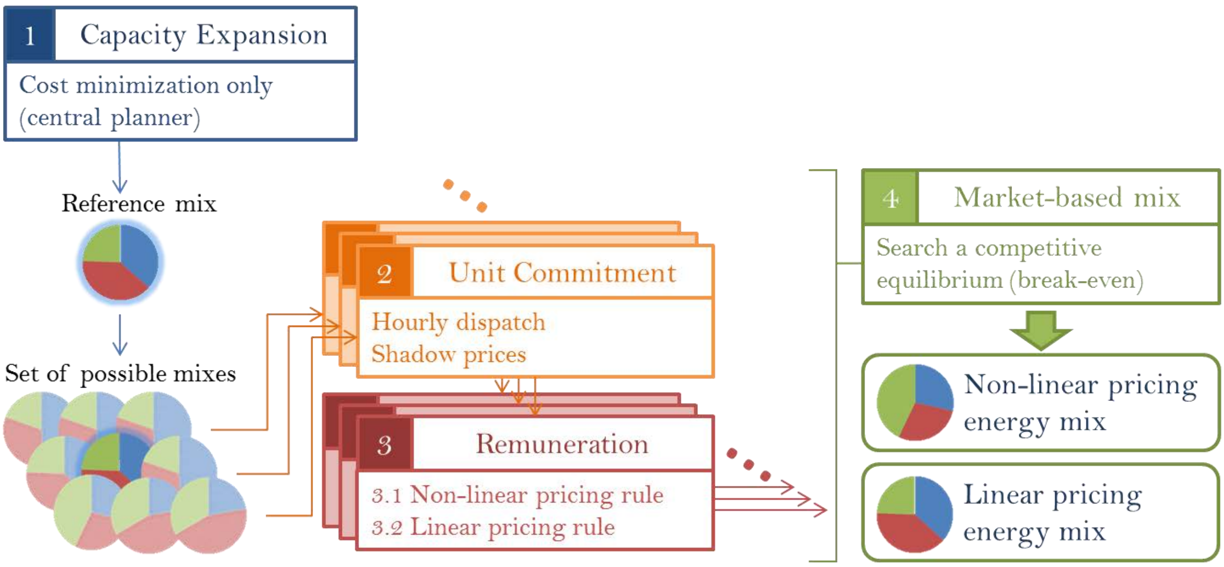

Figure 1. Methodology summary diagram.

2.1 Module 1: Reference generation mix

Module 1 calculates the least-cost energy mix using a traditional capacity expansion model as in a centralized planning case[4]. This energy mix is used only as initial reference for the subsequent search of the perfectly adapted mix corresponding to each of the pricing rules. Since in principle market prices are believed to drive investment towards the least cost generation mix, we assume that the market-based mixes to be obtained later will not deviate substantially from this reference, although as it is right next described, we explore up to around 4000 different alternatives.

We build a set of possible mixes by considering all combinations of the three thermal generation technologies which amount to n^3 possibilities (where n is the maximum number of units considered for each technology). In a real size example this produces a number of possibilities in the order of 10^6. We reduce the search by excluding those mixes that significantly deviate from the initial reference to handle some thousand combinations only. This way, the computation time[5] in following modules is minimized while maintaining an extensive set of possible solutions, so that an optimum can be found.

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

2.2 Module 2: Short-term Unit Commitment

Module 2 takes as an input a given energy mix and simulates the day-ahead market outcome for a full year. The output of this module includes the detailed economic dispatch and the hourly marginal costs.

We consider a single node system, so no locational marginal prices (LMP) are produced. This way prices will have the same impact on each investment decision regardless of the location of power plants. In turn, price influence on investment behaviour will be easier to analyse. We assume perfect competition, so generators are supposed to declare their true marginal and non-convex costs. The UC formulation is detailed in section 3.1.

2.3 Module 3: Price and remuneration calculation

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

The computation of prices and side-payments is detailed in Section 3.1 and 3.2. No reserves or other ancillary services are considered in this simulation since our interest is on differences produced exclusively by the aforementioned pricing rules on the day ahead energy-only market[6].

2.4 Module 4: Market-based mix search

Module 4 compares all the previously evaluated generation mixes to obtain, for each of the pricing rules, the best adapted mix. This direct search approach is similar to that of Shortt et al. (2013), who, to calculate a least cost portfolio, evaluated all possibilities separately and then chose the optimal solution by direct search. In our case the desired energy mix for each pricing rule is not the one minimizing total

[4] The model used in this step includes a detailed representation of both expansion and operation. The formulation is similar to that of presented later in Section 3.1, but the number of units available of each technology is in this case variables to be determined by the problem itself. To do so, obviously associated investment costs are included in the objective function.

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

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

costs, instead, we consider as optimal the mix that a competitive market would choose to invest on. The corresponding market-based optimality conditions are based on the condition that all agents are break-even. In other words, an agent would choose to invest if and only if short-term market remuneration fully ensures the recovery of both investment and operation costs. On the other hand, a perfect competitive market will ensure that the short-term remuneration exactly recovers the previous costs[7]. The details are provided in Section 3.3.

3 THEORY/CALCULATION

3.1 Unit Commitment formulation

An accurate short-term simulation is necessary to obtain precise results in the long term. Our first attempt was to use a complete UC as the one presented in Morales-España et al. (2013) to simulate the short-term operation of the day-ahead market for a whole year. This approach made the problem computationally intractable so our next step was to reduce the number of variables by considering only a few representative weeks instead of a year. This approach could have been successful for other purposes but it was not appropriate for ours. This is because important discontinuities that affect the long-term problem are introduced when this simplification is applied.

For example, the amount of time intervals with scarcity of capacity is a key issue to determine the long-term adequacy of an energy mix. When generation capacity is insufficient the market price is set at the so-called non-served energy (NSE) price. If properly determined (i.e. if turns to be a good proxy of demand's utility), this price is the required remuneration to promote the properly adapted investment in capacity, and it is crucial to allow for the investment cost recovery of all units in general and peak-load units in particular. If only a few weeks are considered in the problem a discontinuity is introduced in the number of time intervals in which the price is at the NSE level. For example, if four weeks were considered and the result was then scaled to a year, the number of intervals with NSE price in a week would be multiplied by thirteen. This discontinuity produces big differences in the remuneration of all units when small changes are made in the mix yielding unrealistic results. Therefore, a full year representation is needed.

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

3.1.1 Nomenclature

Indexes and sets

$g \in G$ Generating technologies

$t \in T$ Hourly periods

$g \in G^{MR}$ Must-run generating technologies

Parameters

C_g^{LV} Linear variable cost of a unit of technology g [$/MWh]

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[7] If the market remuneration was above these costs, competitors would enter de market and depress prices down to the break-even point.

C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]
C_g^{SU}	Start-up cost of a unit of technology g [$]
D_t	Load demand in hour t [MWh]
PV_t	Solar photovoltaic available production in hour t [MWh]
$\overline{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]
RD_g	Ramp-down rate of unit g [MW/h]
RU_g	Ramp-up rate of unit g [MW/h]
N_g	Number of units installed of technology g

Variables

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

3.1.2 Formulation

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

$$s.t.\quad \sum_{g\in G}\left\lfloor \underline{P}_g u_{g,t}+p_{g,t}\right\rfloor + PV_t - pv_t^{spill} = D_t - nse_t \qquad \perp \rho_t \qquad \forall t \tag{2}$$

$$u_{g,t}-u_{g,t-1}=v_{g,t}-w_{g,t} \qquad \forall g\notin G^{MR},t \tag{3}$$

$$p_{g,t}\le\left(\overline{P}_g-\underline{P}_g\right)u_{g,t} \qquad \forall g\notin G^{MR},t \tag{4}$$

$$p_{g,t+1}-p_{g,t}\le RU_g \qquad \forall g\notin G^{MR},t \tag{5}$$

$$p_{g,t-1}-p_{g,t}\ge RD_g \qquad \forall g\notin G^{MR},t \tag{6}$$

$$0\le u_{g,t},v_{g,t},w_{g,t}\le N_g,\quad u_{g,t},v_{g,t},w_{g,t}\in\mathbb{Z} \qquad \forall g\notin G^{MR},t \tag{7}$$

$$u_{g,t}=N_g,\quad v_{g,t},w_{g,t}=0 \qquad \forall g\in G^{MR},t \tag{8}$$

$$p_{g,t}=N_g\left(\overline{P}_g-\underline{P}_g\right) \qquad \forall g\in G^{MR},t \tag{9}$$

$$pv_t^{spill}\le PV_t \qquad \forall t \tag{10}$$

$$p_{g,t}, nse_t, pv_t^{spill} \geq 0, \quad p_{g,t}, nse_t, pv_t^{spill} \in \mathbb{R} \qquad \forall g,t \tag{11}$$

Equation (1) shows the objective function to be minimized which is a sum of all operation costs (no-load cost, linear-variable cost, start-up cost and shut-down cost) and the value of the non-served energy. Restriction (2) equals production (allowing solar PV production to be reduced by a certain amount if needed) with demand minus non-served energy. As well-known, its dual variable ρ_t represents the marginal cost of the system for each time interval. As shown in equation (7), binary variables are here integer with the upper bound being the number of units installed. In this model we consider a must-run restriction for nuclear power plants so the constraint (9) fixes the power output to its maximum. For an extensive description of a UC model see Morales-España et al. (2013).

3.2 Non-linear (discriminatory) pricing rules

Non-linear pricing rules are the most extended alternative in markets with complex auctions. This is the case of most US markets such as NYISO (2013), MISO (2013a) or ISO-NE (2014).

The general approach consist, as described in the introduction, in obtaining a uniform marginal price from the unit commitment model (marginal cost) and giving additional side-payments on a differentiated per unit basis. Side-payments are sometimes referred to as make-whole payments or uplifts. In practice, a side-payment is calculated as the difference between the incurred costs of a unit (according to its offer) and its uniform-price-based market remuneration[8]. The difference generally considers the complete day costs and incomes (i.e. side-payments are calculated on a daily basis, not hourly) and only exists if the difference is positive (if costs happen to be higher than market remuneration). This paper follows this simple approach to compute non-linear prices[9] and side-payments according to:

$$\text{UniformPrice}_t = \rho_t \tag{12}$$

$$SP_{j,day} = \max\Big(\sum_{t \in day} [\underbrace{C_j^{NL} u_{j,t} + C_j^{LV}(\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t}}_{\text{Operation Costs}} - \underbrace{\rho_t(\underline{P}_j u_{j,t} + p_{j,t})}_{\text{Market Remuneration}}], 0\Big) \tag{13}$$

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

$$\sum_{t \in day} \rho_t \left(\underline{P}_j u_{j,t} + p_{j,t} \right) + SP_{j,day} \tag{14}$$

3.3 Linear (non-discriminatory) pricing rules

Linear pricing rules rely on a uniform price to account for variable and fixed (non-convex) costs at the same time. This can be achieved in a number of ways: different authors propose alternative pricing mechanisms to reflect non-convexities in the marginal price perceived by all units (see for example Vázquez (2003), Hogan and Ring (2003), Gribik et al. (2007) which minimize side-payments or Ruiz et al. (2012) which completely eliminates side-payments). These methods seek to minimize side-payments

[8] Again, here we have restricted the scope of the paper to the energy only day ahead market. When adding in the analysis more products or subsequent markets, the side-payments may include other concepts such as the opportunity cost derived from providing reserves.

[9] Some more refined methods to calculate side-payments are worth mentioning -see for example O'Neill et al. (2005)- although not representative of current market practices.

and find a price that truly captures the value of energy (this is the reason why they are called non-discriminatory, although in most cases some sort of side-payments are still needed)[10].

Since side-payments would still be necessary in most cases (although minimal), this approach, strictly speaking, should still be considered discriminatory. On this paper though, we will refer to these pricing rules as linear representing the fact that non-convexities are considered in price formation and distinguishing it from the non-linear rule previously introduced.

All of the mentioned alternatives are similar in nature although very different in its implementation. Probably the most promising alternative is the convex-hull pricing (Gribik et al., 2007) which is the foundation of the recently accepted MISO proposal of extended locational marginal pricing (ELMP).[11] The method proposed by MISO does not follow completely the convex-hull methodology (or full-ELMP) in favour of a computationally simpler formulation. This simplified method is based on virtually allowing fractional commitment of some units, even though fractional commitment is not physically feasible, and allocating the corresponding share of non-convex costs on the market price.

We chose to use a similar approach, generally referred to as "Dispatchable Model". It consists in a modification of the unit commitment model used for dispatch in which binary restrictions are relaxed. This way some units are partially committed and now, marginal costs depend on non-convex costs since an additional unit of energy would require an increase in the continuous commitment variable. Only equation (7) needs to be changed to:

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{R} \qquad \forall g \notin G^{MR}, t \tag{15}$$

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

$$\text{UniformPrice}_t = \rho_t^{relax} \tag{16}$$

$$SP_{j,day} = \max\left(\sum_{t \in day} \left[C_j^{NL} u_{j,t} + C_j^{LV} (\underline{P}_j u_{j,t} + p_{j,t}) + C_j^{SU} v_{j,t} + C_j^{SD} w_{j,t} - \rho_t^{relax} (\underline{P}_j u_{j,t} + p_{j,t})\right], 0\right) \tag{17}$$

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

$$\sum_{t \in day} \rho_t^{relax} \left(\underline{P}_j u_{j,t} + p_{j,t}\right) + SP_{j,day} \tag{18}$$

Note that the dispatch remains the same as in the non-linear case; the linear pricing rule only affects the remuneration by producing a higher uniform price through the dual variable of the relaxed problem which reduces the side-payments requirements.

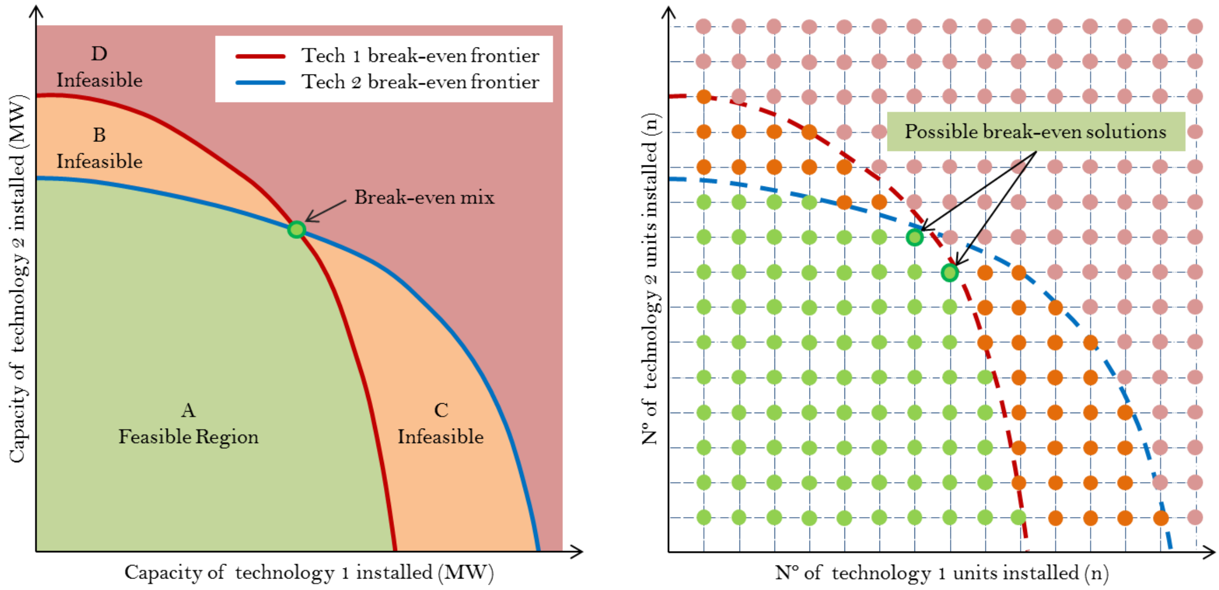
3.4 Market-based mix search

To illustrate our methodology to find the perfectly adapted mix, first consider the following simple case with only two generation technologies. In order to determine how much capacity of each of the technologies will be installed, all possible combinations of technology one (T1) and technology two (T2) are represented in the plane shown in Figure 2 (a).

[10] A real case example is the pricing rule implemented in Ireland (SEMO, 2013) where an ex-post optimization model increases marginal prices in the least costly way until all units recover their declared costs. In this case no side-payments are needed and all units perceive the same price.

[11] See MISO (2013b) and FERC (2012).

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



(a) Continuous investment break-even mix (b) Discrete investment break-even mix

Figure 2. Break-even solutions.

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

Figure 2 (b) represents this methodology applied to a discrete investment problem, which is our case. Break-even frontiers can be interpolated from the point cloud and the continuous break-even mix obtained as the intersection. However, we are considering the more realistic discrete investments which present a lumpiness problem. As illustrated in the figure, no point will probably coincide with the continuous break-even mix and various discrete energy mixes may seem valid under the break-even criteria. To discern which of these nearly optimal points is preferred, the value of the net social benefit (NSB) resulting under each of the mixes is compared and the NSB-maximizing mix is selected.

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

4 RESULTS

Three different energy mixes are calculated and compared. First, the least-cost (reference) energy mix from a centralized perspective is obtained as described by module 1. Around this reference mix a set of possible mixes containing 3706 potential solutions is built. All these possibilities are characterized by modules 2 and 3. Module 4, considering market-based investment decisions, selects the two mixes that best adapt to a non-linear and a linear pricing rule. These results are obtained in a context of a rather significant solar PV penetration (19.2 GW-peak) in a power system supplying the chronological hourly demand for Spain 2012 (40.4 GW-peak). The data used to represent each power plant type is summarised in Table i.

Table i: Generating technologies characteristics[12]

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

$C^{NSE} = 5000$ $/MWh

Figure 3 shows first the minimum cost reference mix followed by the mixes resulting from applying the two different pricing rules considered. Both the mix produced by the linear pricing rule and the mix produced by the non-linear pricing rule deviate from the reference mix. In fact, none of the pricing rules supports the reference energy mix (i.e. they do not provide sufficient remuneration to make all units in the reference mix profitable), which would be a desirable characteristic of a pricing rule. Both pricing rules require a deviation from the reference mix including a slight decrease in total capacity. This deviation though, is significantly smaller when the linear pricing rule is applied.

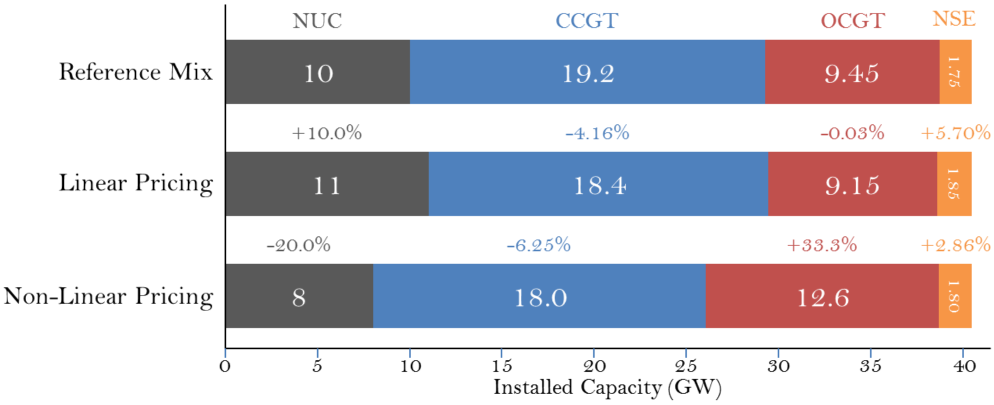
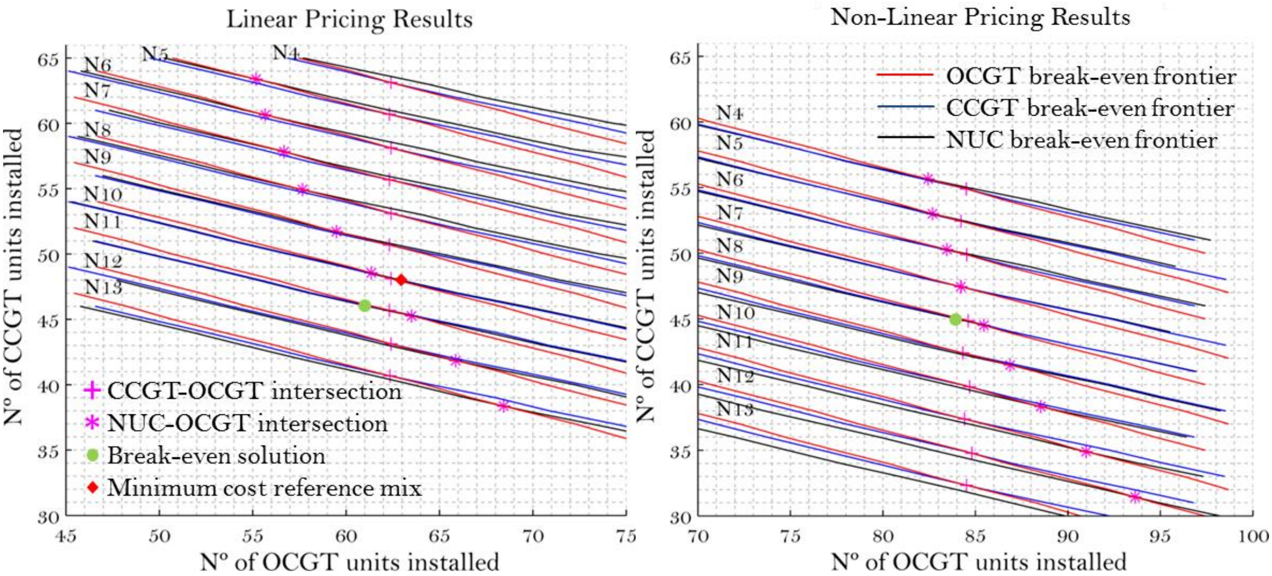


Figure 3. Generation mix results.

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

To gain more insight, the representation presented in Figure 2 has been extended to include three technologies and the results of this simulation are shown in Figure 4. Doing this requires an extension to 3 dimensions but for the sake of clarity this figure shows 2-dimensional break-even frontiers obtained for all combinations of CCGT and OCGT units and only discrete combinations of nuclear power plants. These frontiers can be thought of as the contour lines of the three surfaces that should intersect only at the break-even solution point. This way, a point where all three contour lines intersect will indicate the desired solution but this point may not be represented in the figure since the optimal continuous solution could require a non-discrete level of nuclear capacity.

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



(a) (b)

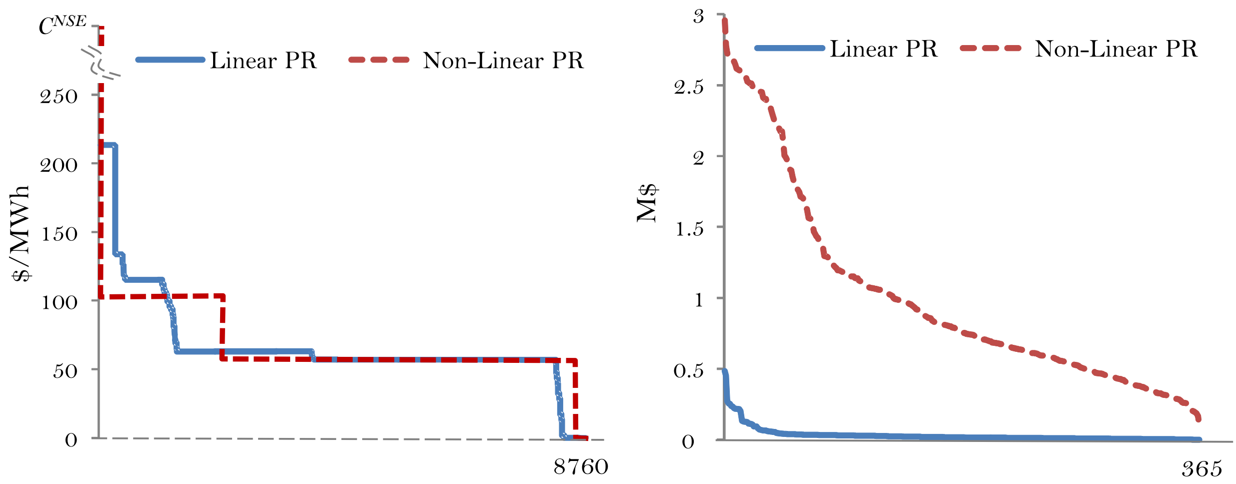
Figure 4. Break-even frontiers under (a) linear and (b) non-linear pricing rules

Figure 4 (a) shows the result for the linear pricing rule. To easily find the point where all three surfaces intersect look at the crosses (+) which represent the intersection of the CCGT (blue) and OCGT (red) lines and the asterisks (*) which represent the intersection of the NUC (black) and OCGT (red) lines. The perfectly adapted generation mix to be installed under a linear pricing rule would have between 10 and 11 nuclear power plants. Since we are assuming that only discrete investments are possible the final solution requires 11 nuclear power plants and is indicated by the green dot. The red diamond points the minimum cost reference mix, it is hard to tell with the figure but it is located outside of the feasible boundary.

The same analysis can be made for Figure 4 (b) which shows the results for the non-linear pricing rule. The ideal solution would lie between 7 and 8 nuclear power plants but the discretization simplifies it to 8. Note the difference in the horizontal axis; in this case the perfectly adapted mix requires a totally different amount of OCGT capacity and the reference mix lies out of the bounds of this plot.

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

In Figure 5 (a) we sorted in descending order the hourly uniform prices produced by each of the pricing rules in the corresponding energy mix. The non-linear price consists of four different regimes; the price is set to C^{NSE} when not enough capacity is available, the other two steps correspond to OCGT and CCGT variable costs. Nuclear power plants can never be marginal since they are not able to regulate their output, therefore the price is set to zero when production exceeds demand and solar PV production is spilled. The linear pricing rule is not limited to these four steps and a continuum of prices is possible. Compared to the non-linear case, the price is lower when the additional nuclear power plants substitute CCGT units and when CCGT units replace OCGT units. Figure 5 (b) illustrates how daily side-payments are, as expected, reduced by the linear pricing rule.



(a) Monotone curve of uniform market prices (b) Monotone curve of daily side-payments

Figure 5. Pricing regime comparison between linear and non-linear pricing rules

5 DISCUSSION

This section aims to qualify the results presented previously, mainly to determine the relevance of the pricing rule and to clarify some common misconceptions.

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

$$TotalCost_{year} = \sum_{t \in year} nse_t C^{NSE} + \sum_j \sum_{t \in year} OperationCost_{j,t} + \sum_j AnnualInvestmentCost_j \qquad (19)$$

Figure 6 details the share of each component of total costs. It is clear that the linear pricing energy mix is composed of more capital intensive technologies with lower variable costs. Interestingly, the share of non-convex costs (no-load and start-up costs) is relatively small (around 7%) although these are responsible for the price differences between each of the pricing rules and thus, responsible for the difference in the final energy mix.

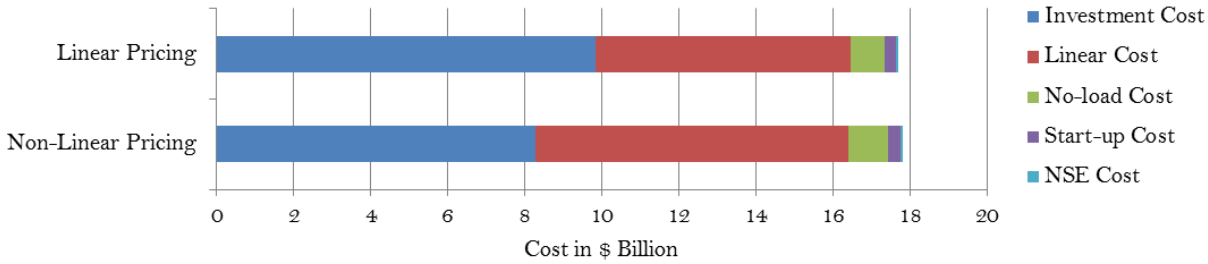


Figure 6. Cost structure of each generation mix

In particular, start-up costs only represent around 1.5% of total costs. This suggests that we could use the so-called screening curves (SSCC) method (Phillips et al., 1969) to gain some more insight on the results we are obtaining. In particular, we use an alternative representation of the SSCC (Figure 7), where the horizontal axis which generally represents hours of operation of each generation technology (up to 8760 hours) here represents installed capacity. This simply requires a change of variable using the relation between time and power given by the net load-duration curve of the system[13]. The area under each curve represents the costs incurred when a certain capacity of each technology is installed.

In this type of representation we get the total cost involved when instaling a MW of each of the technologies at each of the load levels (under the simplified dispatching assumptions of the SSCC methodology).

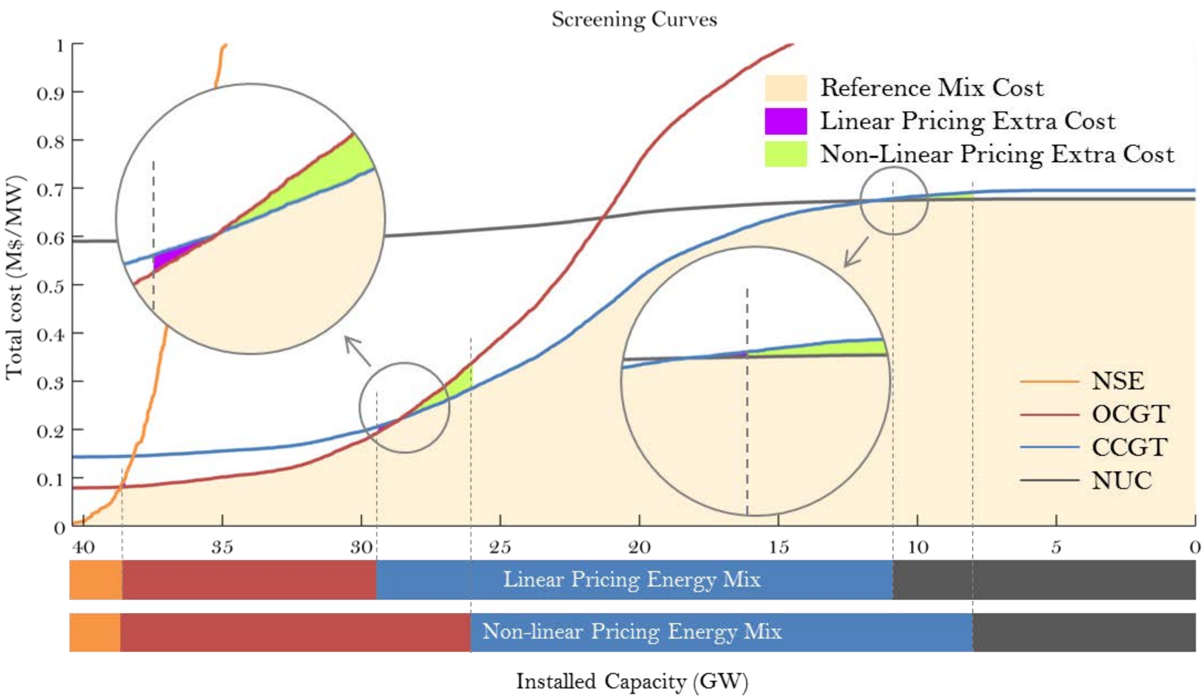


Figure 7. Screening curves representation of total costs

This figure should help to better interpret what at first might seem a counterintuitive result: the structure of the optimal mix changes significantly as a consequence of the pricing rule implemented, but the total costs are affected to a lower extent when compared in relative terms. With this representation we shall see that effectively not-so insignificant changes in the mix may not affect total costs in relative terms.

To begin with, let us graphically identify the total cost of the optimal mix obtained with the SSCC method as the solid area of the figure above. Now we shall compare the costs resulting from the mixes depicted in figure. The extra cost of the non-linear pricing mix is produced by the excess of peak-load capacity and the lack of base-load capacity. These extra costs are represented by green areas in the figure and are relatively small if compared to the total costs of the system.

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

Table ii: Total cost comparison of the resulting mixes

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

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

As already illustrated by the SSCC, the percentage difference with respect to the minimum cost is very small for both pricing rules so it could seem that the impact of pricing rules in total costs is negligible. Actually, we should first know what can be called a small difference in this context and what the impact of installing a sub-optimal generation mix can be. One clear reason for this difference to be small is that the cost data considered for mid-load units makes it a very competitive technology for peak-load and base-load alike and this diminishes the effect of deviations in the energy mix. Take for instance a mix in which only CCGT units are installed; this mix would produce a 3% increase in total costs with respect to the minimum cost reference mix. Considering this we can say that the non-linear pricing rule produced a relatively big increase in total costs while the linear pricing rule produced a cost increase two orders of magnitude lower.

We now compare the result of applying (changing) the pricing rule to the adapted-to-the-other-pricing-rule energy mix. We can see how the changes are relevant (Table iii). The non-linear rule does not produce sufficient remuneration for the linear mix and the linear rule produces excessive remuneration for the non-linear mix.

Table iii: Investment cost recovery under different generation mix - pricing rule combinations

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

This allows to extract two additional conclusions. First, in the previous table it is clearly illustrated that the performance of one or the other pricing rule can only be judged in the long run: it would make no sense to evaluate the suitability of the implementation of one rule on the basis of the estimated returns or costs calculated for a mix adapted to any other market design context, or even to the mix resulting from a pure cost minimization. Second, from the regulatory design point of view, it has been evidenced that a change in the pricing rule would produce an economic imbalance requiring new investments but also divestments that could take a long time before a new economic equilibrium is reached. So, although further research would be needed, regulators should be discouraged to change the particular pricing rule in force (linear or non-linear) since the negative impact of “disadapting" the mix could be relevant, and the potential benefits in the long run are yet not clear enough.

6 CONCLUSIONS

This paper has proposed a practical and computationally efficient methodology to compare the long-term effect of pricing rules in the investment signals perceived by market agents. We asses this impact in terms of the expected energy mix to be installed under different pricing rules.

A real size example of a power system was used to compare two pricing rules; a non-linear pricing rule resembling current market practices in the US and a linear pricing rule including the main characteristics proposed in literature. Two important results can be extracted from this simulation. First, the way in which non-convex costs are reflected in the uniform price can have a significant impact in the investment signals perceived by market agents and the linear pricing rule seems to promote a more efficient energy mix. Second, contrary to what a superficial analysis may suggest, a linear pricing rule does not necessarily produce higher energy prices than a non-linear pricing rule; in fact it can lower the price since it attracts generation technologies with lower variable costs.

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

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IMPACT OF DAY-AHEAD MARKET PRICING RULES ON GENERATION CAPACITY EXPANSION

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Overview

Pricing rules in wholesale electricity markets are usually classified around two major groups, namely linear (aka non-discriminatory) and non-linear (aka discriminatory). As well known, the major difference lies on the fact that only the first approach does include non-convex costs (start-up and no-load cost of the marginal technology) in the market price perceived by all units. In the non-linear alternative these costs are only recognized to the units not recovering total production costs via marginal market prices, being paid if necessary as “make whole” payments.

According to the classical marginal pricing theories, the resulting market prices are supposed to serve as the key signals around which capacity expansion revolves. Thus, the implementation of one or the other pricing rule may have a different effect on the investment incentives perceived by generation technologies, affecting the long-term efficiency of the whole market scheme.

In this context, the growing deployment of Renewable Energy Sources for Electricity (RES-E) can enhance these potential differences. RES-E penetration increases the cycling operation of conventional thermal plants, raising non-convex costs of these plants (mainly as a consequence of the increase of the wear and tear of the plant, usually reflected in the Long Term Service Agreements, LTSA), see Batlle & Rodilla (2013).

In this paper the objective is two-folded: first we review how long-term investments incentives can be affected by the pricing rule implemented. To do so, we rely on the long-term results obtained with a simulation model which is applied to a real-size thermal system (Herrero et al, 2014). On this basis, we focus on the analysis of the potential effect of RES-E on the previous discussion. That is, on whether a large penetration of RES-E (in particular solar PV) could exacerbate the differences between using one or the other pricing rule. As described next, we approach the generation expansion planning problem by properly considering the effect of the aforementioned thermal cycling costs dynamics and its impact in price formation.

Methods

We base our analysis on a long-term greenfield simulation of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.) are considered in the simulation. The mix to be optimized has to supply the hourly demand of Spain for 2012. The exogenous solar PV production profile has been scaled from the 2012 production profile in Spain.

Our goal is to find the perfectly adapted energy mix that should be installed under different pricing rules. The computation of this perfectly adapted mix is based on the major assumption that, when perfect competition is considered, the market-driven mix corresponds to the one guaranteeing satisfactory remuneration for generators (break-even remuneration) and at the same time maximizing the net social benefit.

The general approach followed consists of analyzing, under the point of view of the previous conditions, a large set of possible generation mixes. This way, the proposed approach is similar to that presented in Shortt et al. (2013); although in our case the focus is on market income, and not on production costs. In order to reduce the space of potential mixes to be considered, we first obtain a starting reference mix by using a traditional expansion planning model. This model aims at minimizing the total operating and capital costs on a future target year, but it considers centralized decisions instead of independent competitive investments. The reference mix is then used to generate around it different combinations of plants of the three thermal technologies mentioned.

For each case in the set of possible generation mixes, a sufficiently detailed unit commitment model (representing start-up costs, minimum stable loads and ramps) is first run, providing the complete economic dispatch and the hourly marginal costs. Once these marginal costs/prices are known, we evaluate on the one hand the necessary side-payments (corresponding to the non-linear pricing rule) and on the other, the extended price (for the case of the linear one) that guarantee that all the scheduled units fully recover their operation costs, including the non-convex costs. For each of the two pricing rules evaluated, the best adapted mix is the one fulfilling the best way possible the two criteria previously enounced. This process is applied to a set of scenarios with an increasing amount of RES-E installed (solar PV) to determine the influence of RES-E penetration in the potential differences between these two pricing schemes.

Results

Figure 1 shows the resulting energy mixes for 3 different levels of solar PV penetration. For each scenario, the bar on the left represents the perfectly adapted mix when short-term prices result from the application of the linear pricing rule and the one on the right the corresponding to the non-linear one. Generally speaking, it can be noted that a linear pricing rule attracts more investment in capital intensive technologies (base-load plants) which allow for a saving in operational costs. In the non-linear case the non-convex costs are not embedded in the market prices perceived by base-load plants, so as evidenced in the analysis developed, the incentive to enter the system for these technologies is weaker.

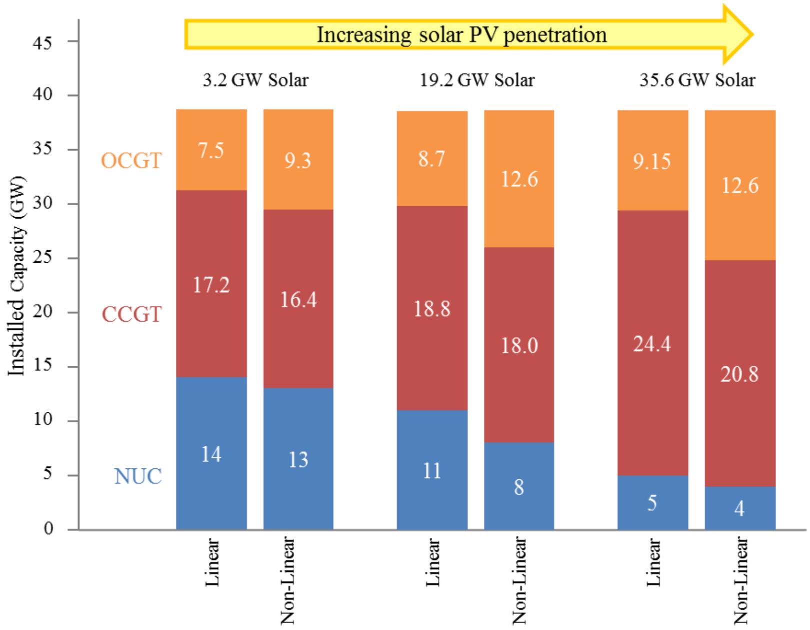

Figure 1

Conclusions

Previous studies have shown that a large penetration of variable energy resources can increase the differences between the remuneration received by base-load plants in different pricing schemes (Veiga, et al., 2013). In this paper we provide evidence on the base of an integrated capacity expansion analysis. We argue that the pricing rule implemented can substantially affect the resulting energy mix and its importance will increase with the introduction of RES-E, making it a key part of energy policy.

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