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MODELING THE ROLE OF EXISTING HYDRO RESOURCES IN THE CAPACITY EXPANSION PROBLEM IN FACE OF A SIGNIFICANT PENETRATION OF SOLAR PV

Pablo Rodilla [a], Carlos Batlle [a, b], Andrea Veiga[c], Michael Hagerty[d]

[a] Institute for Research in Technology, Comillas Pontifical University, Sta. Cruz de Marcenado 26, Madrid, Spain

[b] Also with MIT Energy Initiative, 77 Mass. Av., Cambridge, US and Florence School of Regulation, Florence Italy

[c] Endesa, Ribera del Loira 60, Madrid, Spain

[d] The Brattle Group, 44 Brattle Street, Cambridge, MA, US.

As well-known, wind and especially solar PV generation change the short-term scheduling of the conventional thermal plants, affecting in the end the long-term optimal thermal investments.

The amount of capacity and the particular technologies needed to optimally cope with large penetration levels of renewable are system dependent. In particular, in those systems where there is an existing amount of “shiftable in time” generation such as hydro power, these changes in the optimal long-term thermal investments needs are expected to be relaxed.

This paper further develops a screening-curves-based capacity expansion model to allow analyzing this problem. First, we describe the two heuristic algorithms we add to the screening-curves based approach that respectively allow introducing a detailed hydro-dispatch and hourly price computation. This extended solution provides a remarkable trade-off between the accuracy of the results and the computation times.

Then, we illustrate how existing hydro resources effectively relax the impact on the long-term expansion. We do so by applying the approach proposed to a real-size hydro-thermal case example, in which large amounts of solar PV are to be installed.

Keywords

Hydro-thermal generation dispatch, renewable energy sources, generation capacity expansion.

1 INTRODUCTION

Wind, and especially solar PV generation, when reaching a significant penetration level, among other effects, change the short-term scheduling regime of the conventional thermal plants, reducing utilization factors and increasing the need of cycling[1] [1][2][3][4].

In the long term, the previous short-term operation-related changes also impact the capacity expansion problem, for the optimal technologies to be installed also change with this new requirements. For instance, there will be increasing needs of generation units with higher cycling capability along with lower capital investment costs [5].

In this new context, finding ways to properly assess how the large deployment of wind or solar PV affects the future generation mix is a major challenge in the field of electric power systems modeling. Capacity expansion models need to be able to efficiently represent the short-term economic scheduling and production costs, for it might no longer be suitable to disregard short-term operation details when analyzing the long-term expansion problem [6],[7].

Different modeling approaches have been proposed to tackle the complete expansion-scheduling problem. In this respect [6],[8],[9] and [10] represent (among many others) some clear examples of how to face this matter with different modeling complexity detail.

The authors of this paper, presented in [11] a heuristic modeling approach based on augmenting the screening curves (SSCC) methodology. The model is based on a heuristic short-term thermal optimization model which is embedded in the classic SSCC methodology [12]. The so-resulting model provides a detailed representation of the economic scheduling of the thermal generating units and the resulting operation costs (including cycling costs), while keeping the SSCC well-known capability to provide valuable analytic insights on the capacity expansion problem at a very low computational cost.

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[1] The term "cycling" refers to the cyclical operating modes of thermal plants that occur in response to dispatch requirements: on/off operation, low-load cycling operations and load following.

The aforementioned changes that wind and solar PV introduce in the short-term scheduling of conventional thermal plants are more acute in the absence of the flexibility provided by the "shiftable in time" generation or demand resources. Examples of these "shiftable in time" resources are those provided by manageable hydro, storage or demand response. The availability of these resources can significantly soften the short-term impacts introduced by wind and solar, and therefore relax the long-term needs towards other type of capacity.

As pointed out in [4], despite of being a quite active research topic, almost none of the capacity-expansion-plus-dispatch models feature reservoir hydro power. This can be seen as a serious shortcoming of the literature. This is precisely the focus of this paper. In particular, the objective of this work is two-folded:

- We explore the long-term requirements of a hydro-thermal system when increasing the penetration of solar PV. The focus will be on the potential of a given capacity of manageable hydro to flatten the abrupt changes in the net load caused by solar PV production.
- In order to analyze how the long-term mix evolves, and the consequences in terms of costs and market prices, we first further develop the approach presented in [11], by enhancing the model in two directions: (1) a heuristic hydro dispatch optimization algorithm is developed. The algorithm proposed could be effectively used in models using heuristics approximations of the hydro dispatch. The hydro dispatch approach presented proves to be superior to the most well-known heuristic hydro dispatch method: the peak shaving method. The model presented provides a suitable trade-off between computation time and accuracy of results. And (2), a simplified method to compute short-term prices in the two more relevant pricing contexts (linear and non-linear pricing[2] [13][14][15]) is presented.

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[2] . These two pricing contexts mainly differ in the way that non-convex costs are considered in the price formation process. While the linear context does include these non-convex costs in market prices, the non-linear does not and therefore there may be necessary adding make-whole payments on a unit by unit basis to complement the remuneration.

The paper is structured as follows: first in Sections 2 and 3 we present the heuristic algorithms for both the dispatch of hydro resources and also for price computation respectively. Then, in Section 4, we first briefly review how the long-term investments are affected in purely thermal systems when increasing penetration of variable energy resources. We then use the complete screening curves hydro-thermal model to analyze how the previous insights change when the system has available hydro resources. We focus on a prototypic real-size power system inspired in CAISO, which is used to illustrate the relevant synergies that arise between manageable hydro and solar (in terms of cost savings, resulting prices and the capacity value of solar). Finally Section 5 concludes.

2 THE NEW HEURISTIC HYDRO DISPATCH METHOD

When just variable energy costs and no operating constraints are considered in the representation of the thermal generation units, the optimal unit commitment of an already installed generation mix greatly simplifies. In this case, the minimum cost dispatch simply entails loading the thermal units at their maximum output according to the merit order established by their variable energy costs.

When this rather simplified thermal dispatch can be used to reasonably replicate the reality, the hydro dispatch can also be very much simplified. In this particular case, the most economical alternative to allocate hydro energy is by producing in the upper-most part of the system load. This classic heuristic hydro dispatch is commonly known as the peak shaving method [16], and it traditionally served to model hydro production in a surprisingly simple and reasonably accurate way when compared to more detailed models [17].

However, the advent of wind and solar PV resources has completely made the previous assumption of the thermal dispatch, based on the variable-cost-based merit order, no longer valid [5], [6]. Among other reasons, this has happened because wind and solar PV have increased the relevance of the thermal start-up costs in the short-term dispatch.

This more relevant role of start-ups was the basis for the heuristic approach presented in [11]. In the same line, the new heuristic algorithm for hydro it is proposed aims at providing a still simple method while better coping with this new more challenging context.

The objective is to minimize the cost of supplying the net (or residual) load demand (demand after subtracting the solar PV in our case) with the hydro and thermal plants in the system. We aim at replicating the optimal economic dispatch that would result from the implementation of a MIP unit commitment optimization while at the same time solving the problem considering hourly granularity in reduced computation times.

2.1 The basic heuristic idea

Hydro plants are characterized by means of two parameters: the maximum available energy[3] and the maximum power output.

The basic algorithm consists of four sequential steps

Step 1: Computation of the preliminary dispatch of thermal generation. The model builds upon a preliminary scheduling of the thermal units. Dispatchable hydro production is not considered in this first preliminary dispatch. The objective at this point is to generate production and cost profiles for thermal generation to meet the net load. In our particular case, we determine this thermal predispatch using the LEEMA model [11], but any short-term thermal model could be used at this stage.

Step 2: Identify and separate all the cycles of operation of all the thermal units. That is, identify all the production profiles and the costs involved in every thermal unit production cycle from the start-up to the shutdown. These production cycles are denoted as "bricks" in the following. The concept of bricks is the key around both the hydro dispatch method and the price computation method (Section 4) revolves.

[3] The determination of the hydroelectric available energy in each period (e.g. months) are obtained from a higher decision level model.

Figure 1 represents a schematic dispatch consisting of seven bricks (each color representing a different technology).

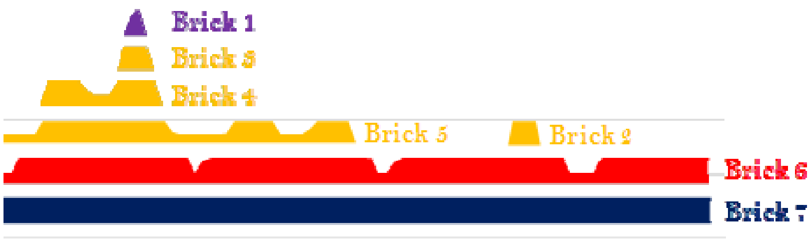

Figure 1. Production profiles with seven "bricks"

Figure 2 schematically illustrates a thermal production brick. For the purposes of subsequent calculations, it is important to identify within each brick the periods in which the unit is producing at the minimum technical output[4].

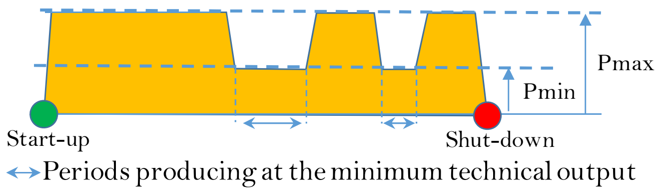

Figure 2. Schematic representation of a thermal "brick"

<u>Step 3:</u> Calculate for each brick (denoted by *b*), the average cost of the energy (per MWh), denoted as AC_b. In this step all the costs taken into account in the unit commitment problem have to be properly allocated to each brick. The more detailed the cost representation of the thermal predispatch the more precise the hydro dispatch will be.

The model we have used for the thermal dispatch considers three sources of costs: (1) energy fuel (EFC_b, as a function of the energy output, including the no-load cost), (2) start-up (SFC_b, as a function of the number of hours the unit has been off-line) and (3) operation and maintenance

[4] As it is well known, the cost per MWh increases when thermal units are run at minimum output. However, this regime is often used as a cost efficient solution when the alternative is to incur in a shut-down followed by a start-up within a narrow time horizon.

(OMC_b, including the effect of cycling, as discussed in [11]). Thus, in our case, the total cost of a brick can be schematically determined as follows:

$$AC_b = \frac{EFC_b + SFC_b + OMC_b}{E_b}$$

Where E_b is the total energy that corresponds to brick *b*.

Once the average cost of all bricks has been calculated, the bricks are sorted in decreasing order of their average cost of production.

Note that, roughly speaking, the larger the number of hours producing, the lower the impact of start-up costs on the average cost of the energy of the brick. This is the reason why, in Figure 1, brick 2 has a higher average cost (and thus situated before in the sorted list of bricks) than brick 4.

<u>Step 4:</u> Hydro scheduling. Taking into account the two parameters defining a dispatchable hydro plant, we substitute one by one the thermal bricks, starting with the one presenting higher average costs, and continuing in the descending order established in step 3 until the energy of the hydro plant is completely depleted.

Figure 3 illustrates how the algorithm would begin allocating hydro resources in the simplified representation seen in Figure 3. It is worth noting that the algorithm tends to eliminate the bricks which are usually located in the peaks, since they are the most expensive (per MWh) ones. Note that these peaks do not always correspond to the upper-most load levels, but rather to local maximum values of demand.

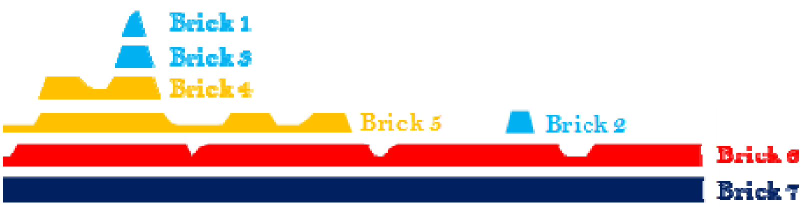

Figure 3. Heuristic hydro dispatch (cost-saving method)

As we proceed with the previous algorithm, two cases need further refinement of the heuristic methodology so as to better represent reality: (1) the substitution with hydro production of the thermal bricks where the maximum power output of the hydro becomes binding, and (2) the substitution with hydro production of the bricks in which the thermal unit was producing some hours at the minimum technical output.

In the first case it is important to note that once the maximum power output becomes binding, the whole thermal brick cannot be longer substituted with hydro production. As a consequence of this, the start-up cost of that thermal cycle cannot be avoided. This is illustrated in Figure 4, where in (A) it is first represented a simplified thermal predispatch along with the maximum power output of hydro. As we apply the previous dispatch criterion we first substitute brick 1 and then brick 2 with hydro production. However, as we try to keep on dispatching hydro with the described criterion we find that the next brick (brick 3) cannot be completely eliminated. This happens because of the maximum power output of the hydro plant, which does not allow us to avoid the thermal production energy represented with the dashed area.

When this is the case, it becomes evident that the start-up cost of that brick cannot be avoided, and therefore the average cost of such brick is no longer the suitable measure for potential savings. In this case we have to recalculate the average cost of such brick by subtracting the start-up cost. Once we have recalculated the average cost of the brick (subtracting the start-up cost), all bricks need to be sorted again in descending order. This will turn the brick being analyzed into a less attractive alternative to be substituted by hydro.

However, if at some point in the algorithm it becomes the most cost-effective alternative, the dispatch is carried out as shown in (C), where it is shown how hydro is only used where the maximum power output is not binding.

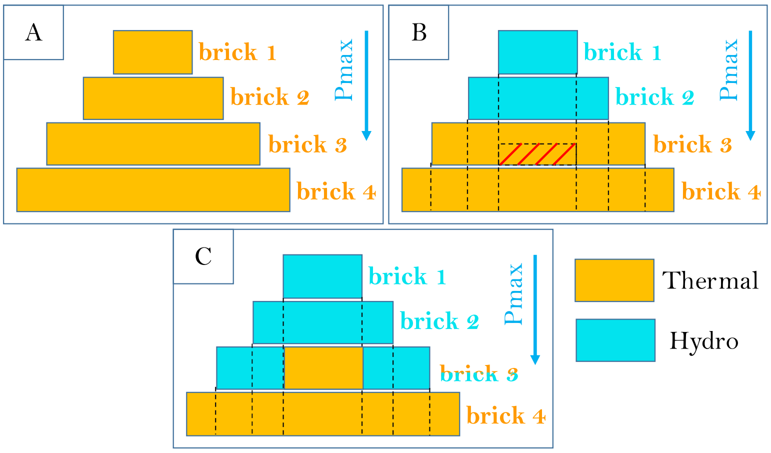

Figure 4. Hydro dispatch when the maximum power output becomes binding

As shown in the figure above, in capacity constrained systems, it is not generally possible to avoid all short term peaks.

The second type of brick which deserve special consideration are those where the thermal production profile includes one or more periods in which the plant is producing at the minimum technical output. For those bricks it has to be evaluated whether it is worth substituting with hydro energy the thermal production at the minimum technical output, or conversely is it better to limit hydro generation in those periods, thus allowing other thermal units to increase their production during valley hours. This alternative dispatch is shown in Figure 5.

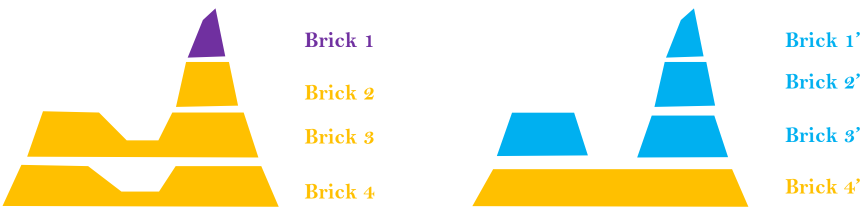

Figure 5. Avoiding hydro production in valley hours

On the left side of Figure 5 it is shown the thermal predispatch. It can be seen that there are some hours between the two load peaks when thermal Brick 3 and Brick 4 are reduced to minimum load to avoid additional startups.

In this case, although there may be enough hydro resources to completely replace the top three bricks, the algorithm will evaluate whether it is worth limiting hydro production in the valley hours. If this was the case, only the portion of Brick 3 operating at full capacity will be replaced by hydro production as can be seen on the right side of Figure 5, where Brick 3' has now been split into two hydro dispatch periods. The remaining production of Brick 3 (the one corresponding to valley hours) is transferred to Brick 4, which is at a lower load level, instead of being replaced by hydro.

During the valley hours, the algorithm checks whether there is available capacity to be increased at a lower load level to take on this generation instead of replacing it with water.

Step 5: the result of the previous hydro operation schedule is used to recalculate the final hydro-thermal dispatch. To do so, we take now the hydro production as an input data and use it in the calculation of the net load profile. On the basis of this new net load profile, a final thermal dispatch is run. Running again the thermal dispatch serves to correct potential imperfections of the heuristic process, such as those derived from running sequentially the thermal and the hydro dispatch.

2.2 The model proposed versus the traditional peak shaving

The algorithm was tested for validation using data from the Spanish system in 2012. 17 large plants schematically representing the Spanish hydro production where modeled for both the peak shaving method and the heuristic algorithm proposed. Both models receive as input information the energy each plant has to produce each month and also the maximum and minimum output limits. These parameters were determined on the basis of real data, therefore implicitly assuming perfect foresight.

The execution of the real-size case example, for a full year (8760 chronological hours) took to the heuristic hydro-thermal dispatch 29.7 seconds (programmed in MATLAB® R2013b, and run on an Intel Core i7 @ 2.8 GHz, 3.5 GB RAM).

Generally speaking, both the proposed algorithm and the peak shaving method perform reasonably well with respect to reality when the output coming from renewables is stable and the net load does not suffer relevant changes from one day to another. However, when the wind and/or solar PV output changes significantly the daily net load patterns, the heuristic proves to be superior to the traditional peak shaving.

As a way to illustrate this, we present in the figure below the hourly net load (in black) in a week where the wind production introduced relevant changes in the daily profiles. In the figure it can be seen how the peak shaving algorithm tends to overproduce when the net load is higher, disregarding that there can be expensive thermal production to be avoided at lower demand levels.

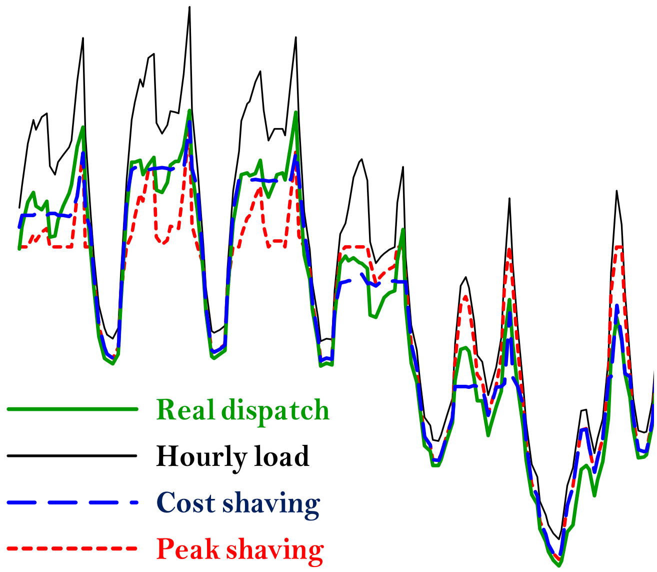

Figure 6. Heuristic approach proposed versus the traditional peak shaving method

3 THE HEURISTIC PRICE COMPUTATION MODULE

Once the final hydro-thermal minimum cost dispatch is determined, we calculate the resulting hourly market prices following another heuristic method developed to that end.

The algorithm for the price determination consists of two initial steps which are run irrespective of the pricing rule to be later modeled:

Step 1: Identify all the cycles of operation (bricks) of all the thermal units (as described in the hydro dispatch method) and properly allocate all involved production costs to each individual brick.

Step 2: Calculate the hourly marginal costs. This is done under the hypothesis that this cost corresponds to the variable cost (not including no-load cost) of the thermal plant which is producing in between the minimum technical output and the maximum output limits. In Figure 7 it is represented for illustrative purposes how the marginal costs are identified within the heuristic method.

As shown in the same figure, when only a must run type of plant (e.g. nuclear in our simulations) is producing, the marginal cost is assumed to be zero, for this only happens in practice when there is spillage of renewable production. For the same reason we assume a zero marginal cost whenever there is only full-load must run and all other units producing are at the minimum technical output.

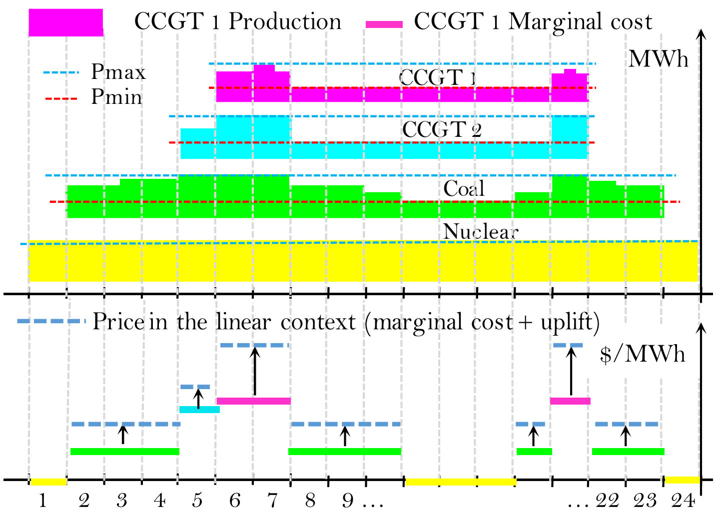

Figure 7. Marginal cost and uplift determination

It is a well-known result that when hourly prices are set equal to the hourly marginal costs, full operation costs recovery is not ensured [13],[14],[15]. This happens because the so-called non-convex costs (e.g. start up or no-load) are not reflected in the marginal costs. Two major alternatives exist to guarantee cost recovery, (1) to pay on a unit by unit basis the cost non-recovered by marginal costs -the non-linear pricing approach- and (2) to add hourly uplifts to hourly prices perceived by all units -the linear pricing approach-.

Step 3: determining market prices and market remuneration in the two pricing contexts of interest. Short-term market remuneration is assumed to be settled every 24 hours, and therefore, the following methodology is run for every day contained within the simulation horizon.

Determining the remuneration in the non-linear context entails calculating for each unit the difference between the costs associated to its production and the marginal-cost-based market income. Only in case such difference is positive, an additional payment equal to this difference is provided to the unit.

In the case of the linear context, we run the following iterative method.

- We start with the unit producing at a highest load level (CCGT1 in Figure 7). In the hours the unit is marginal, we evenly add uplifts[5] in such a way that the unit recovers all its operation costs with the market remuneration. In this first case there are some hours in which the unit is not marginal because of producing at the minimum technical output. During those hours it is assumed that market price will be the marginal cost determined in step 2.
- Once we have determined the corresponding uplifts we proceed with the next thermal plant (the one loaded just below, CCGT2 in the figure) and apply the same idea. During the hours in which the unit is marginal, we evenly add uplifts to the marginal-cost based price in such a way that the unit recovers its production costs. In this more general case, there are two reasons why the unit is not marginal in a certain hour: (1) another unit loaded at a higher load level is marginal in that hour (CCGT1 in hours 6, 7 and 15) or (2) because the unit is producing at the minimum technical output (hours 8 to 14). In the first group of hours it is considered the unit receives the price (including the uplift) that has been previously determined. In the second group of hours we proceed as previously explained.

[5] Uplifts can only be positive or zero.

4 ANALYSIS OF THE ROLE OF EXISTING HYDRO RESOURCES IN THE CAPACITY EXPANSION PROBLEM INCLUDING LARGE PENETRATIONS OF SOLAR PV

In purely thermal systems, the increase of penetration levels of variable energy resources in general, and solar PV in particular, significantly changes the capacity needs of the system in the long-term. Growing amounts of variable energy resources calls for technologies with higher cycling capability and lower capital costs (typically, combustion gas turbines, CGT in the following) [5],[6].

Increasing the amount of installed capacity of CGT can have also an impact in the resulting market prices, for it usually represents the type of generation with higher variable production costs. This effect adds up to the two short-term impacts of variable energy resources on prices: the merit order effect and the increased cycling operation [1].

On the other hand, the capacity value of solar is generally quite limited in purely thermal systems. Here it is usually made distinction between those systems with summer (cooling) peak loads and those with winter (heating) peak loads. While in the former solar PV has a small capacity value, in the latter the capacity value is close to zero.

We next explore whether these long-term impacts hold or to what extent they are relaxed when there is in place an amount of hydro storage resources. To that end, we make use of the complete enhanced SSCC model, which adds to the basic methodology presented in [11] the two heuristic algorithms presented in Sections 3 and 4.

4.1 The test system

The model has been used to simulate a CAISO-like system (see the data in the Appendix). The objective is to show how solar PV impacts the long-term planning of a system when there is a non-negligible component of hydro resources.

4.2 Impacts on capacity expansion and the corresponding operation

Short-term dispatch

As regards short-term dispatch, as a way of illustration we show the results for the CAISO-like system for two representative summer and winter weeks (Figure 8).

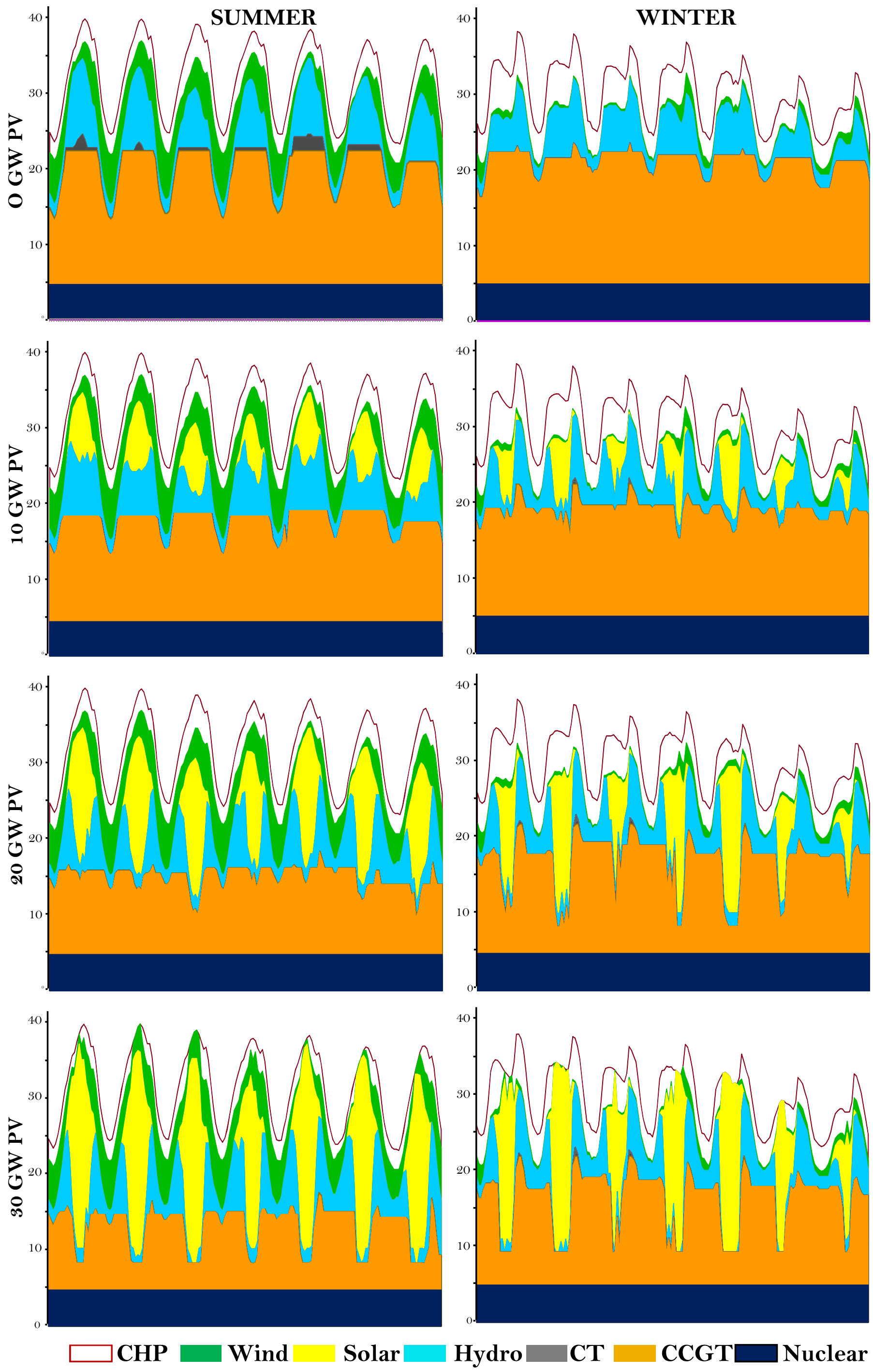

Figure 8. Evolution of the hourly scheduling when the mix can re-adapt (CAISO-like long-term study)

In each row it is represented the result for a different penetration level of solar PV.

- The baseline scenario (0 PV) in Figure 8 clearly shows the characteristic (daily) peak shaving dispatch carried out by hydro plants. The reason why net load is not always perfectly shaved is because hydro plants have a maximum output limit. In the absence of this limit, net load peaks would be completely flattened.

- The hydro dispatches in the summer and winter weeks in the 5 GW PV scenario is highly illustrative of what the joint availability of hydro and solar resources can and what cannot achieve. Let us first focus on the summer week, where the positive synergy between both technologies can clearly be observed. Both dispatches can be coordinated in such a way that the resulting net peak load is peak shaved with the sum of energies produced by hydro and solar. This enhanced peak shaving is possible because the maximum output of hydro is not binding the final dispatch. We find the opposite situation in the winter week. In the baseline scenario (0 PV), we can see how the hydro production leaves a peak of demand in the daily peak period (the maximum power output limit is reached). In this case, the addition of solar resource availability outside this peak period cannot be used to reduce the output. In winter, therefore, although the coordination of solar and hydro also exists, it is less effective than that achieved in summer.

- As solar penetration increases above 15 GW, the maximum power production of hydro no longer allows for complete peak shaving of the demand. We therefore begin to have an analogous situation to that described for winter. The fact that the flexibility of hydro leads to such different dispatches for the both extremes represented is also noteworthy. However, note that the driver is the same: to reduce the net load peaks.

- Since the annual peak demand values take place in summer in CAISO, when the coordinated dispatch allows for a more effective peak shaving, we obtain a significant reduction in capacity requirements.

Long-term investments

In Figure 9, it is shown the evolution of the new capacity requirements as solar PV penetration increases (x axis).

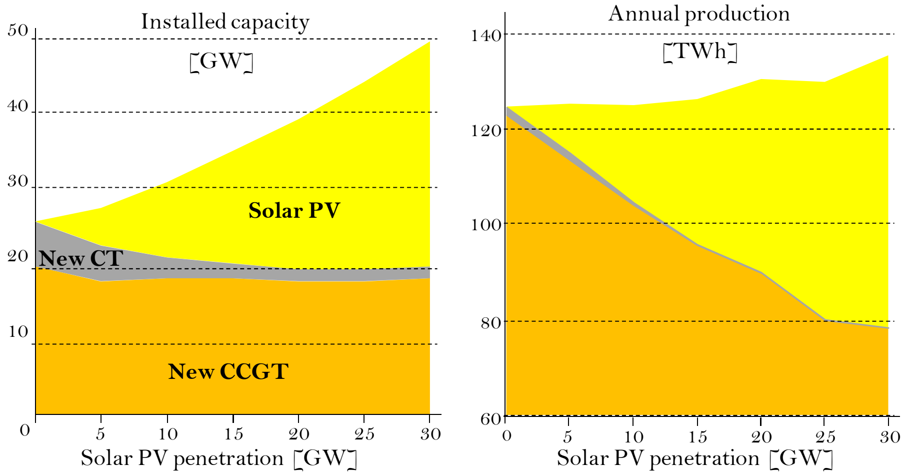

Figure 9- Evolution of the installed capacity and the annual corresponding energy production

Two technologies are installed to meet future needs: combustion gas turbine (CT) and combined cycle of gas turbine (CCGT). This is shown in Figure 9, where both the evolution of the installed capacity for each penetration level and the corresponding (annual) energy production of these new capacity additions are presented.

Several relevant differences with respect to the aforementioned results that would be observed in a purely thermal system can be highlighted:

- The capacity value of solar PV is enhanced for low penetration levels as a consequence of the flexible hydro resources available in the system.

  The reasons for this larger capacity factor stems from the fact that the limited but manageable energy from hydro resources (as any other type of storage) is able to reduce the thin peak that arises at sunset. These synergies are obviously conditioned by both the maximum power output and the amount of energy that can be stored. This can be observed in the representative dispatches (and especially in summer, where the annual peaks take place).

- As a consequence of the joint availability of solar and hydro resources, the larger the solar penetration, the lower the number of CT plants that are required, and the larger the number of CCGT ones. Note that this result again moves in the opposite direction from the one that would be expected in a thermal system.

Market prices

In the figure below, the price-duration curves corresponding to the 3500 hours of higher demand have been represented for each pricing context for the baseline scenario (0 GW PV) and the extreme penetration level (35 GW PV). While in the non-linear context prices only decrease with the installation of solar PV (allowing the mix to change does not increase short-term prices in this flexible system), this is not always the case in the linear pricing one, where prices are higher during a significant number of peak hours (due to cycling and the increasing role of non-convex costs).

Although not shown in the figure, it is worth noting that solar PV depresses prices in the lower demand hours, leading to a total of 2927 hours, with zero prices in both pricing context when the penetration level reaches 35 GW of installed capacity (prices are never zero in the case without solar PV).

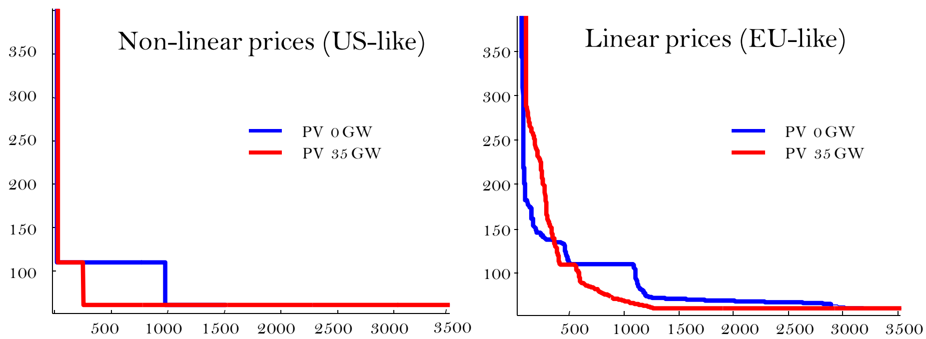

Figure 10. Prices

5 CONCLUSION

Wind and especially solar PV generation change the short-term scheduling of the conventional thermal plants. This fact affects the amount of thermal capacity and the particular technologies needed in the long term, thus affecting total long-term costs and prices.

In this paper we have seen how this previous effect is to some extent relaxed when there is an existing amount of manageable hydro power in the system.

To analyze a real-size case example we have first developed two heuristic algorithms for computing the hydro-dispatch and the resulting hourly prices respectively. These two approaches offer reasonable results at quite competitive computation times, which prove them to be well-suited for long-term expansion analyses.

By embedding these two algorithms in a screening-curves-based model we have found that hydro can (1) enhance the capacity value of solar PV in systems where load is driven by summer cooling, (2) allow solar PV reducing the need for peaking units and (3) soften the short to long-term impact on market prices derived from increasing solar penetration levels.

Acknowledgements

This modeling approach has been developed in the context of the “MIT Future of Solar Study”. Many of the ideas and conclusions have benefited from discussion with the team involved in the project, to which we are indebted. Any errors that may remain are the authors’ only responsibility. We also thank Samuel Vázquez and Prof. Pérez Arriaga for their fruitful support.

6 ANNEX: DATA USED IN THE SIMULATIONS

- Thermal generation data (investment cost, fuel cost, heat rate, etc.) is based on the following sources:
  - NREL SunShot Vision Study. February 2012.
  - “Cost and performance data for power generation technologies” Prepared by Black and Veatch for the National Renewable Energy Laboratory in 2012.
  - Start-up costs have been taken from the Long-Term Transmission Analysis 2010–2030 (ERCOT.com).
  - Economic life: 20 years and a rate of return of 10.2%.

  A brief summary of the data is shown in the table below:

TABLE I
THERMAL GENERATING TECHNOLOGIES COST STRUCTURES

Tech.	Nuclear	CCGT	GT
Heat Rate [Mbtu/MWh]	10	7	10
Fuel Cost [$/Mbtu]	1	8	8
Energy fuel cost [$/MWh]	10	56	80
Variable O&M [$/MWh]	0	5	30
Total variable [$/MWh]	10	61	110
Overnight cap. cost [kS/MW]	6200	1200	660
Annualized capital cost [kW/MW]	738.21	142.88	78.58

- Hourly load in 2030:
  - The reference annual profile has been based on the hourly demand in 2011, taken from the California ISO Open Access Same-time Information System (OASIS).
  - To scale the profile to the year 2030, a constant growth in demand of 1% per year has been assumed.
- Wind and Solar production profiles data have been obtained from daily Renewables Watch (published by CAISO).
- When considering hydro units, the following characteristics of the hydro system have to be introduced as input data: maximum output, run-of-the-river capacity and the maximum energy available in each period. We have estimated these parameters by resorting to the historical production data profiles (also from daily Renewable Watch).
- The already installed generation mix for the long-term study consists of 10 GW of wind, 8.5 GW of cogeneration and 7.95 GW of thermal capacity (the mix is represented in the figure below).

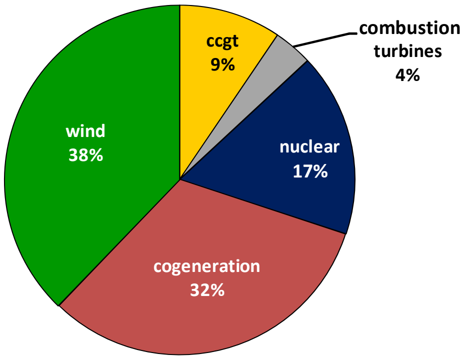

Figure 11. Already installed capacity for the CAISO-like system

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