INSTITUTO DE INVESTIGACIÓN TECNOLÓGICA

# FINAL REPORT

STEXEM

## Task 3: Policy Analysis

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# 1. Overview of Task 3: Policy Analysis

This task aims to analyze the effect of policy instruments on investment in RE technologies as well as transmission-capacity expansion. In section 1.1, we summarize the methodology, presented in Task2, to evaluate the policy implications of acknowledging the strategic behavior of GENCOs in the generation and transmission expansion planning. In section 1.2, we provide insights on the different effects of the most common types of policy instruments, and tackle the critical issue of long-term policy uncertainty and short-term RE uncertainty on transmission and generation expansion decisions, assuming a Spanish case study. In section 1.3 we extend this analysis, by addressing these complicated policy issues on a European level. Finally, in section 1.4, we present a theoretical framework and an illustrative case to assess the uncertainty in wind resources for bi-level model that anticipate the potential imperfect competition in the market.

## 1.1 Regret Computation Methodology

In this section we compare the planning results of a proactive model (that consider imperfect competition in the market) with those of planning the system in a traditional manner (with a cost-minimization problem that assumes perfect competition and inelastic demand). We summarize here the methodology described in Task 2, and supported by the working paper (Gonzalez-Romero et al., 2020).

To conduct this comparison, we compute what we refer to as *regret*. The regret represents the additional cost (or missing welfare) resulting from planning the system under a cost minimization planning (CMP), where all decisions are considered to be simultaneous and perfectly competitive, compared to planning the system in a more realistic decentralized manner with a proactive planning (PP) where TEP decisions are assumed to be taken prior to GEP decisions and considering market feedback given by GENCOs strategic behavior.

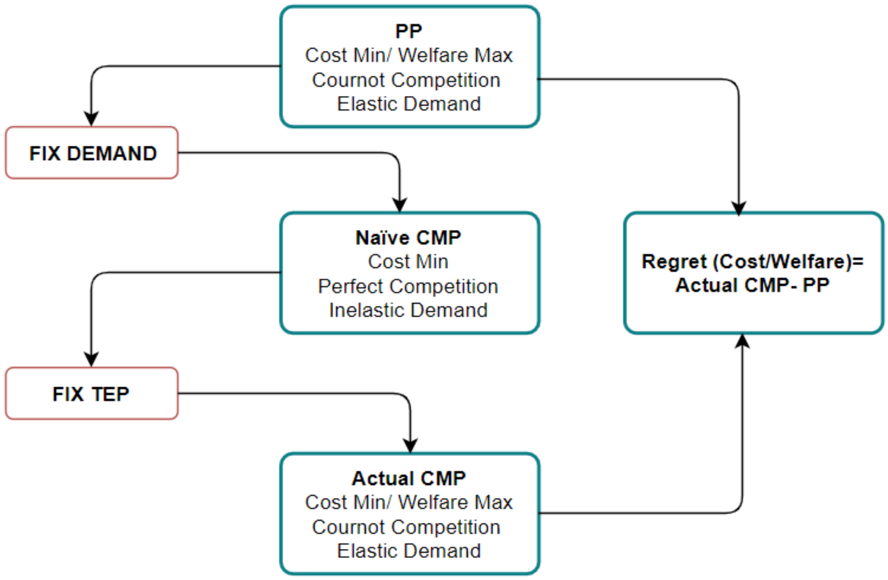


*Figure 1 Regret Computation Methodology*

i. We solve the *PP model* (considering imperfect competition in the lower level).

ii. For the exact same system demand obtained by the PM, we solve the inelastic CMP, which obtains some TEP and GEP investments. We refer to this model as the *Naïve CMP*; it is "naïve" because it does not reflect the strategic behavior of GENCOs. Therefore, the TEP and GEP obtained by the Naïve CMP might be erroneous given that they assume perfect competition, which is not always the case.

iii. We fix the TEP solution obtained by the naïve CMP, the likely solution from centralized system, and we see which would be the reaction of the actual strategic GENCOs. To this purpose, after fixing the TEP solution we re-run the PP model (which is equivalent to just solving the market equilibrium of PP). This allows us to assess to what extent the "wrong" TEP decision, obtained by the naïve CMP, is going to distort the resulting market equilibrium and GEP decisions made in imperfect markets. We call the solution of this third model the *Actual CMP* because it accounts for decision errors made by a cost minimization approach.

iv. Therefore, the regret of using a CMP approach is computed as total cost (or welfare) of the Actual CMP minus the total cost (or welfare) of the PP.

## 1.2 Policy analysis using long-term models: Spanish case

In order to gain policy insights, we conduct case studies comparing different regulatory approaches as well as evaluating the impact of including strategic behavior in the capacity expansion planning. It is important to note that a significant part of this task is related to the collection of the different types of data necessary for creating a Spanish case. We describe this process in section 1.2.1.

Then, in section 1.2.2, we present the policy analysis. In Section 1.2.2.1 and we present the scenarios, to evaluate the different policies. In section 1.2.2.2 we evaluate the impact on the optimal transmission network expansion when taking into account strategic behavior by GENCOs. We show that an optimal policy under a least-cost approach might end up leading to higher social cost than one that rigorously accounts for market power. In section 1.2.2.3 we evaluate the impact of different climate policies, e.g., FIT for renewables, renewable targets, on the optimal transmission network expansion when taking into account strategic behavior by GENCOs, and, more important. Finally, in section 1.2.3 we summarize our findings in the Spanish case.

### 1.2.1 Data Collection

In this section, we enumerate the sources of information that we have used to create a Spanish case. In general, given that there is not an official centralized data hub about the Spanish electric industry, we collect information from several distinctive sources. In particular we base our case study on the work developed by (Ploussard et al., 2018). In this paper, authors propose a reduction technique that aims to create a smaller network equivalent to the original one. In particular, they apply this technique to the European case, from where we extract the data of the Spanish case. This data is collected from a non-official extract of the ENTSOe public web page (Bdw, 2018). This extract takes the information of the network out from the map given by ENTSOe. This is done by associating the geographical coordinates to the each one of the elements of the map.

**Original Buses**

In total, we obtain 932 buses for the Spanish case. This includes buses with ac/dc technology, substations (existing and under construction) for 138, 220 and 400 voltage levels. Please note that we assume, for all the network, a linearized dc formulation as proposed in Task 1.

**Reduced Buses**

The equivalent reduced network consists of 142 buses. Please note that these buses do not necessarily correspond to the physical existing buses extracted from the ENTSOe map. These reduced buses can be represented either by a single already existing bus or by several buses from the original network. In order to represent the reduced buses graphically, we assign the coordinates of the existing bus which has the highest share into the representation of the reduced bus. For more information please see (Ploussard et al., 2018).

## Network

### Original Network

In total, we have 1220 connections in Spain. In Figure 2 we can see the Spanish transmission network resulting from the extract mentioned above.

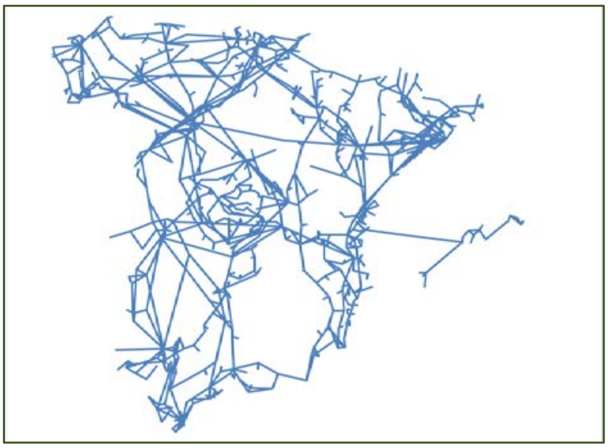

*Figure 2. Spanish Network*

### Equivalent Reduced Network

Figure 3 shows the reduced network, this network is made up of 382 connections. Additionally, the capacity of the lines in the equivalent network is computed by a comprehensive methodology (for details see (Ploussard et al., 2017)).

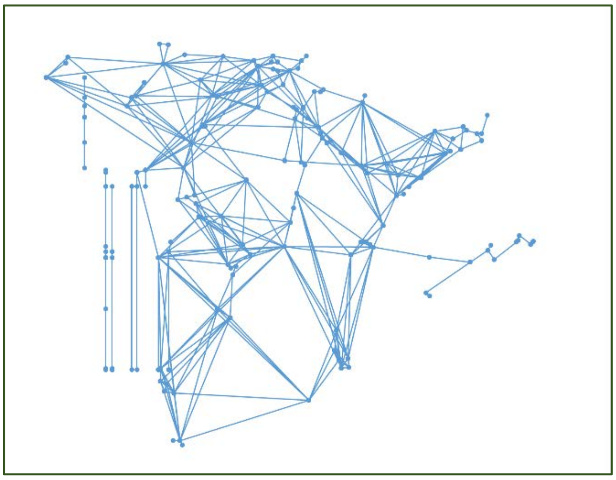

*Figure 3: Reduced Network*

### Demand

We extract the information about the hourly demand from the ten-year development plan published by ENTSOe. Figure 4 shows the hourly demand[1] clustered into 4 representative days following the techniques described in Task 1.

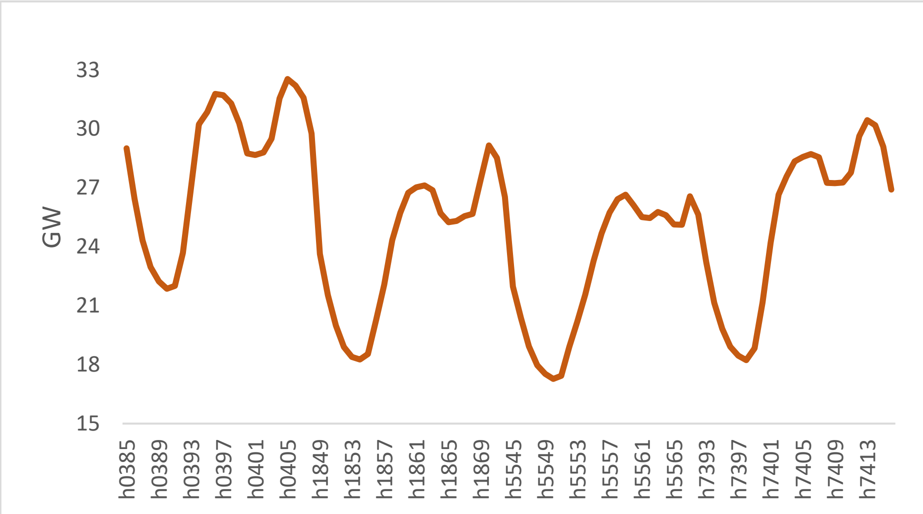


*Figure 4: Demand (Representative Days)*

We do not have information about the distribution of the demand among the buses of the network. Thus, as an alternative, we use the GDP as a proxy to compute demand distribution on each one of the buses of the system. In order to perform this proxy we use GDP information found in the Eurostat web page (EUROSTAT, 2019). On this web page we can find the information of the regional GDP and its correspondent postcode number. Additionally, given that in the ENTSOe map we have the information about the location of each bus of the system, we can associate them with their corresponding postcode number. As a result, we can compute the demand at each bus proportional to the GDP at that bus.

### Generation

As mentioned in (Ploussard et al., 2018) the location and features of most generators, including their technology, and their capacity were, as well, available from the grid data extraction (Bdw, 2018). For the rest of generators, including the solar and wind generation, the data was deduced based on information retrieved from several sources provided by ENTSOe website. Analogously to the demand, these profiles are clustered in 4 representative days.

[1] Please note that we run a multidimensional clustering, taking demand and renewables timer series together.

### Annual Production

In order to validate that our data is consistent in aggregated terms, we compare the 2018 Spanish annual production (RED ELECTRICA, 2020), disaggregated by technology, with the output of our model[2].

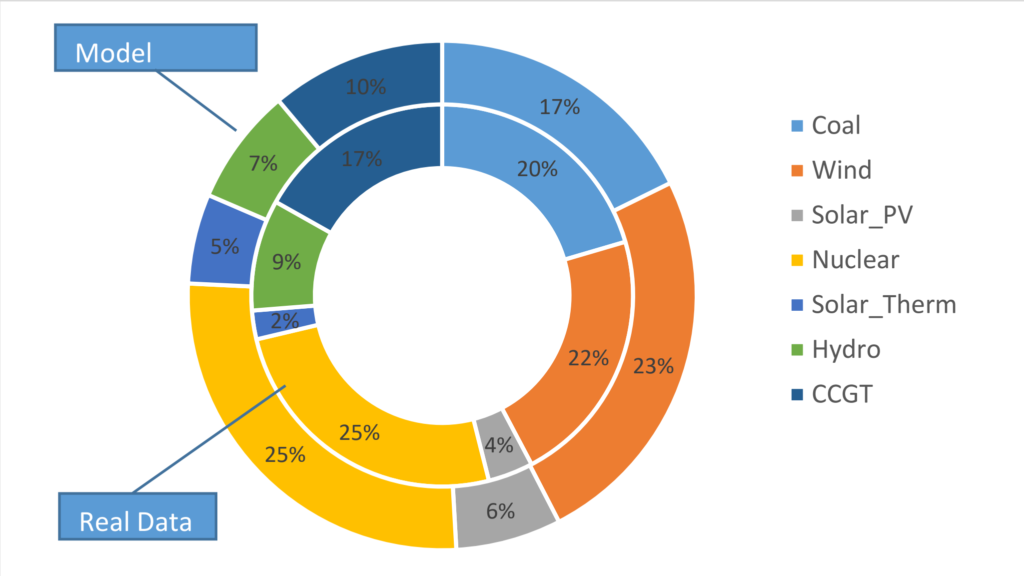


*Figure 5: Spanish Annual Energy Production (Model Results versus Real Production)*

Figure 5 shows that, in terms of the total annual energy, we get a reasonable result similar to the real data. There are, naturally, some differences that result from non-official data extracts, as well as the temporal and the network size reductions applied to the original data.

### Candidate generators

In order to study the generation and transmission expansion planning we take into account the following considerations: i) For the private assets we consider a discount rate of 7% as proposed in the CNMC report ("CNMC," 2018). ii) We consider the CAPEX[3] and OPEX[4] shown in Table I. For new storage technologies we consider store capacity of 8 hours for Batteries and 1 week for hydro.

*Table I: CAPEX for generation technologies*

[2] We run only the market with inelastic demand from the formulation described in Task 1.
[3] Capacity expenditure
[4] Operational expenditure

| | Life Time (years) | Total CAPEX k€/MW | Annual CAPEX k€/MW | Variable Cost €/MWh |
|---|---|---|---|---|
| **CCGT** | 30 | 1300 | 104,76 | 48* |
| **Coal** | 30 | 1300 | 104,76 | 40* |
| **Wind** | 25 | 1000 | 85,80 | 0 |
| **BESS** | 15 | 500 | 54,89 | 0 |
| **Hydro** | 50 | 2000 | 144 | 0 |
| **Solar** | 30 | 650 | 52,38 | 0 |

*Excluding carbon prices

#### Candidate Lines

For the case of the transmission assets we consider a discount rate of 5%, which is the rate used in the last report for the regulated assets according to the (“CNMC,” 2018).

*Table II: Transmission Lines CAPEX for Spain*

| | Location (Latitude ,long) | Reactance (p.u) | Capacity (MW) | Life Time (years) | Total CAPEX k€ | Annual CAPEX k€/y |
|---|---|---|---|---|---|---|
| **L1** | (41.77, 2.86),(41.61, 2.27) | 0,005 | 2000 | 40 | 1300 | 104,76 |
| **L2** | (41.40,-2.57),(42.17,-2.29) | 0,009 | 2000 | 40 | 1300 | 104,76 |
| **L3** | (41.82,-1.53),(42.37,-2.05) | 0,007 | 2000 | 40 | 1000 | 85,80 |
| **L4** | (41.37,-2.12),(42.37,-2.05) | 0,011 | 2000 | 40 | 500 | 54,89 |
| **L5** | (42.67,-1.75),(42.37,-2.05) | 0,004 | 2000 | 40 | 650 | 52,38 |

### 1.2.2 Policy Analysis of the Spanish Case: Impact of Imperfect Planning, Climate Policies, and main Results

In this section we present a long-term analysis on how the Spanish power system can be expanded by considering different policy scenarios. In particular, we study the consequences in the expansion planning of considering imperfect competition in the market. In section 1.2.2.1we present the scenarios to be evaluated. In 1.2.2.2 we show the results of comparing a centralized planning with a proactive one and in Section 1.2.2.3 we expand the results for different scenarios.

#### Climate Policy Scenarios

We consider three climate policy scenarios.

1. Base case: We assume that $CO_2$ prices results in 25 €/ton, which is the most likely to happen according the “State of the EUA EU state report” (Marcu et al., 2019).

2. Paris agreement: In order to achieve the Paris agreement targets a more ambitious policy is necessary, we consider a $CO_2$ price of 50 €/ton.
3. Carbon Neutral: additional to Paris agreement scenario, we forbid the investment in non-renewable technologies.

*Table III: Policy Scenarios for Spanish Case*

| SCENARIO | DESCRIPTION |
|---|---|
| Base Scenario | All possible investment<br>25 €/ton $CO_2$ price |
| Paris Agreement | All possible investment<br>50 €/ton $CO_2$ price |
| Carbon Neutral | Only renewable investment allowed<br>50 €/ton $CO_2$ price |

### Minimum Cost Model vs Equilibrium Model

For the Base Scenario, described in the previous section, we study the implications of planning the system under a cost minimization approach rather than considering the strategic behavior of generation companies.

As we can see from Table IV, there is a total difference of 20M € between the strategic proactive planning and the actual cost-min planning. These results suggest that planning the network and generation expansion under a cost minimization approach, that disregards the potential strategic behavior of GENCOs, would lead to a welfare loss of 21,87 M €. This non-negligible welfare loss in absolute terms is, in fact, negligible in relative terms, given that this would imply only a 0,013% welfare loss compared to a strategic proactive planning approach[5]. However, disregarding strategic market feedback would imply an underinvestment of 20MW in GEP that represent a 0,2% of the optimal generation mix, which can also be considered negligible. Moreover, there is a slightly higher variation, ranging from -0,2% to 1,2%, depending on each technology. Most importantly, in Figure 6 we illustrate how generation siting and sizing varies depending on which regulatory approach is applied.

[5] These results are aligned with those of Task 2. We showed that system with a consistent idle capacity would result in a negligible welfare loss.

*Table IV: Proactive Planning vs Cost-Min Planning Base Case: Spain*

| | Units | Strategic Proactive Planning | Actual Cost-Min Planning |
|---|---|---|---|
| | Lines | L1/L2 | None |
| **Total TEP** | GW | 6 | 0 |
| **Wind** | GW | 9,75 | 9,73 |
| **Solar PV** | GW | 8,00 | 8,00 |
| **BESS** | GW | 1,75 | 1,74 |
| | GWh | 13,98 | 13,95 |
| **Hydro** | GW | 0,51 | 0,51 |
| | GWh | 85,33 | 85,36 |
| **CCGT** | GW | 1,35 | 1,35 |
| **Coal** | GW | 0,83 | 0,82 |
| **Total GEP** | MW | 22,17 | 22,14 |
| **Total Cost** | M€ | 5,207 | 5,201 |
| **Total SW** | kM€ | 164,89 | 164,87 |
| **SW difference** | M€ | | 21,87 |
| **Regret** | % | | 0,013 |

Figure 6 shows that, at some locations and according to a certain regulatory approach, no generation is invested, while in the alternative approach some significant investment is placed. This shows that, even if the relative welfare loss (as well as the variation in the generation investments) might be negligible, some significant changes can occur in terms of the location of generation investments.

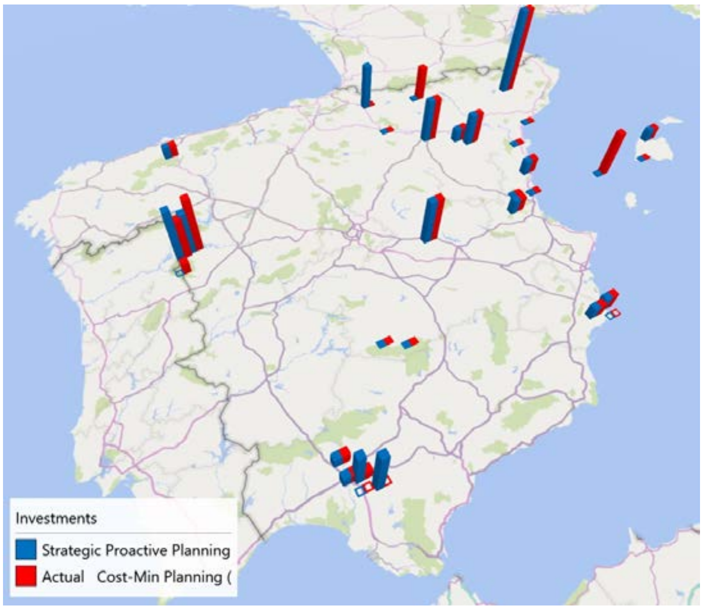


*Figure 6: Generation investment allocation*

Please note that these results are highly dependent on the specific characteristics of each system. In (Gonzalez-Romero et al., 2020) we showed that, disregarding strategic market feedback in a highly congested system can result in a non-negligible planning regret; this result naturally follows, as a heavily congested system is more prone to present inefficiencies if no proper expansion is undergone. Additionally, no clear evidence was found on how elasticity affects the regret of disregarding market feedback, however, it was found that low-congested systems are more sensitive to demand elasticity. As we showed, the Spanish System is in line with these results. We found that a that a well-meshed and low-congested network leads to a relatively small welfare loss.

### Comparison of Climate Policies

In this section we evaluate the climate policies presented in Table III, by comparing the changes in generation mix and $CO_2$ emission for each policy.

Table IV shows the comparison between the proactive and cost-min planning. In general, we can see that the total welfare is similar in every case, which could be explained because the total demand is similar in every case as well.

*Table V: Scenario Comparison for Proactive Planning vs Cost-Min Planning: Spain*

| | Units | Base Case PP | Base Case CMP | Paris Agreement PP | Paris Agreement CMP | Carbon Neutral PP | Carbon Neutral CMP |
|---|---|---|---|---|---|---|---|
| | Lines | L1/L2 | None | L1/L2 | None | L2 | None |
| **Total TEP** | GW | 6,00 | 0 | 6,00 | 0 | 3,00 | 0 |
| **Wind** | GW | 9,75 | 9,73 | 11,23 | 11,21 | 11,96 | 11,94 |
| **Solar PV** | GW | 8,00 | 8,00 | 8,00 | 8,00 | 8,00 | 8,00 |
| **BESS** | GW | 1,75 | 1,74 | 1,90 | 1,90 | 2,21 | 2,21 |
| | GWh | 13,98 | 13,95 | 15,17 | 15,18 | 17,66 | 17,65 |
| **Hydro** | GW | 0,51 | 0,51 | 0,52 | 0,52 | 0,56 | 0,56 |
| | GWh | 85,33 | 85,36 | 86,84 | 86,89 | 93,30 | 93,49 |
| **CCGT** | GW | 1,35 | 1,35 | 1,28 | 1,28 | 0 | 0 |
| **Coal** | GW | 0,83 | 0,82 | 0,63 | 0,60 | 0 | 0 |
| **Total GEP** | GW | 22,17 | 22,14 | 23,54 | 23,50 | 22,72 | 22,70 |
| **Demand** | TWh | 282,71 | 282,55 | 278,06 | 277,90 | 275,92 | 275,85 |
| **Total Cost** | M€ | 5207 | 5201 | 4708 | 4727 | 4539 | 4540 |
| **Total SW** | kM€ | 164,89 | 164,87 | 164,32 | 164,34 | 164,02 | 164,01 |
| **SW diff** | M€ | | 21,87 | | 18,45 | | 9,42 |
| **Regret** | % | | 0,013 | | 0,011 | | 0,005 |

Additionally, we can see that the stricter our climate policy is the lower regret we obtain. This could be explained because with a stricter policy we obtain higher investment in both renewable and storage capacity. This storage capacity could function as a complement to the transmission capacity and, therefore, lead to a lower need of transmission capacity, that in turn, leads to a lower regret. Finally, there is also a significant total cost reduction resulting from the almost zero variable costs of renewable technologies. Please note that the CMP can, sometimes, render a lower cost than the PP model. This happens because the PP aims at maximizing the total welfare and not minimizing the total costs. Therefore, depending on the demand elasticity and degree of competition, sometimes the highest welfare does not coincide with the lowest total cost.

The planning results shown in this section correspond to the Strategic Proactive Planning results for every scenario. Figure 7 shows the investments, per technology, under each one of the policy scenarios. As we can see, there is a significant increase in wind investment from the carbon neutral and Paris agreement scenarios in comparison to the base case. This comes along with an increase in Battery technologies. However, for the case of traditional thermal technologies, namely, coal and CCGT, there is still some non-negligible investments of around 1 GW for each one in the base case and Paris agreement scenarios. These results show that a carbon price alone is not enough to reach a carbon neutral generation investment.

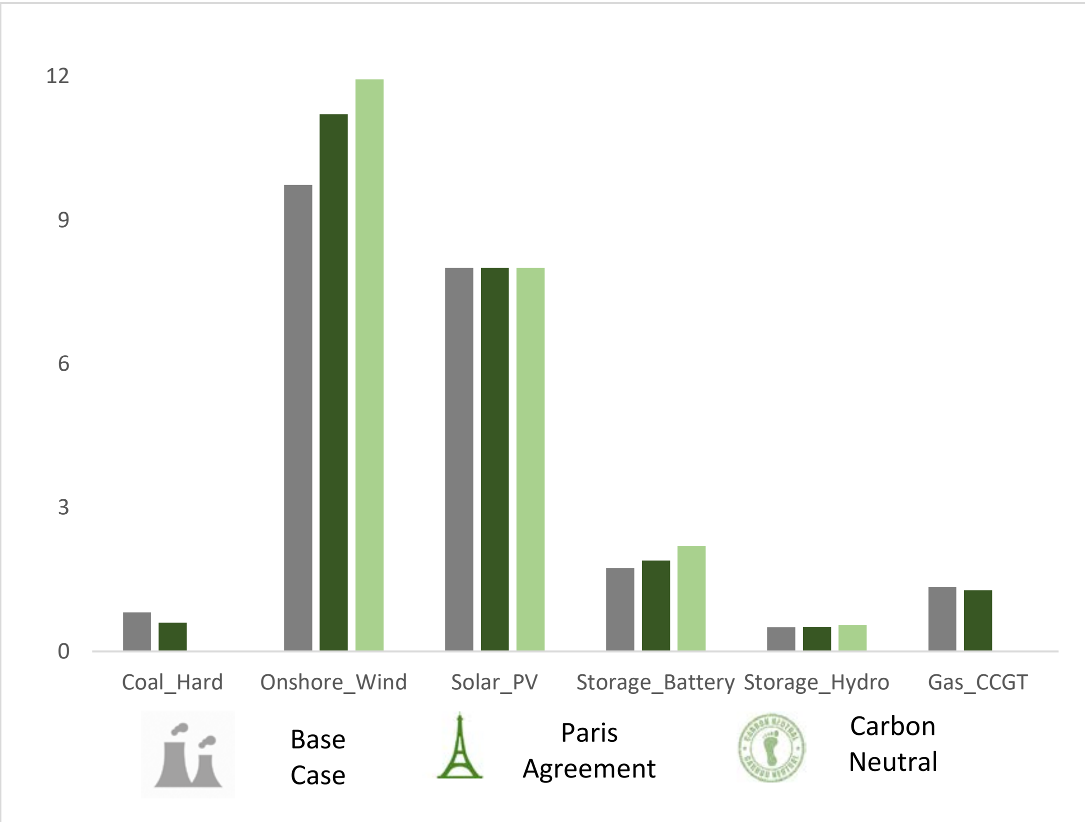


*Figure 7: Generation Mix (New GW installed) in Spain*

Therefore, in the carbon neutral scenario, where we forbid the investment in traditional thermal technologies (coal, gas, liquid fuels) and nuclear, we can see that this implies a further increase in investment in renewable technologies in comparison with the Paris agreement targets. Additionally, these climate policy targets imply a higher reduction of CO2 emission, as seen in Figure 8. Please note these emissions are the result of both the existing and new installed capacity. The Paris agreement scenario implies a 20%

reduction in comparison to the base case and the carbon neutral scenario a further decrease of 27%.

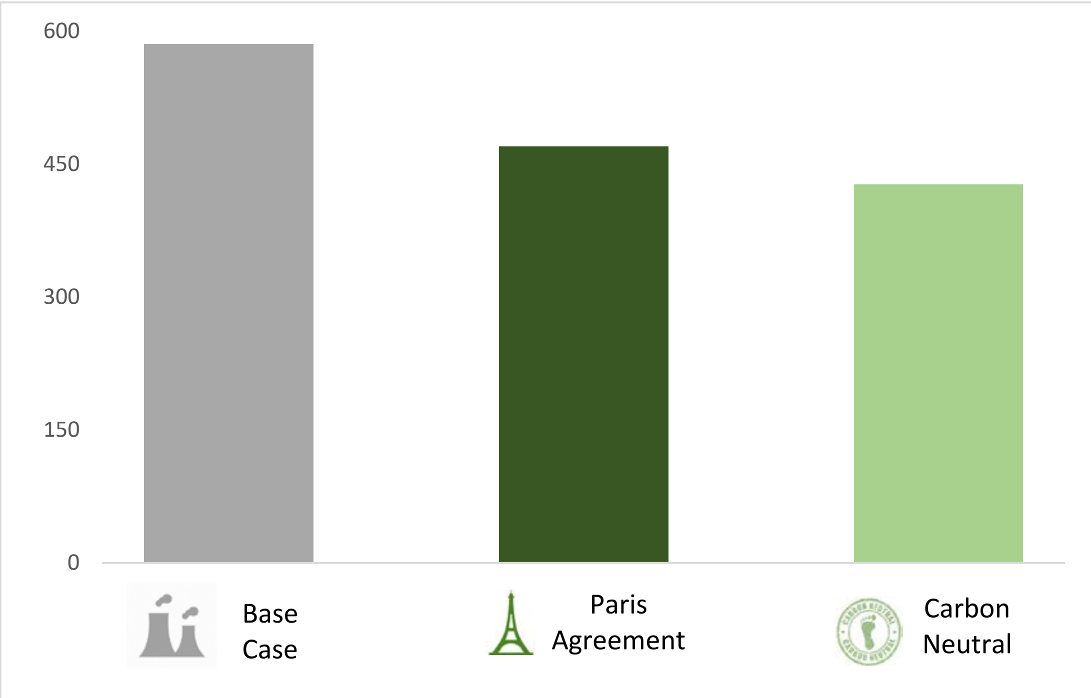


*Figure 8: $CO_2$ Emissions (kton) in Spain*

### 1.2.3 Summary of Spanish Case

In this section we aimed to measure the effects of considering the strategic behavior of generation companies on the capacity expansion planning of the system, namely, transmission and generation expansion planning. For the Spanish system, which is composed of a well-meshed and non-congested network, we found that the welfare effects of disregarding the strategic behavior of market agents can amount to the tens of millions. However, in relative terms to the total welfare, this loss might be negligible. Most importantly, we found that beyond the welfare loss, there might be a slight distortion in total generation capacity invested and a significant distortion in the location where generation would be placed.

Moreover, we found that the current climate targets, derived from the Paris agreement, are insufficient to achieve a carbon neutral generation mix. Apart from these targets, we tested some more restrictive policies, by increasing a possible price of $CO_2$ emissions, which still leads to some investment in thermal technologies. Finally, additional to high $CO_2$ prices we tested an additional scenario to prohibit investment in thermal technologies. We found that this last scenario would finally lead to a 27% decrease in carbon emission compared the mean scenario likely to happen until 2030.

## 1.3 Policy analysis using long-term models: European case

Similar to the Spanish case, we compare different policies to assess the impact of the introduction of diverse levels of renewable energy in a European case study. We also compare the traditional cost-minimization approach with some alternative regulatory approaches to evaluate the impact of considering strategic behavior in the capacity expansion planning.

In Section 1.3.1 we present the data that is mainly taken from the eHighway project (ENTOSOe, 2015). Then, in Section 1.3.1.5, we conduct the evaluation of the different European policy scenarios. In particular, in Section 1.3.2.1, we list the scenarios to be evaluated. In Section 1.3.2.2 we evaluate the impact on the optimal transmission network expansion when taking into account strategic behavior by GENCOs. We show that an optimal policy under a least-cost approach might end up leading to higher social cost than one that rigorously accounts for imperfect markets and market power. In section 1.3.2.3 we evaluate the impact of different climate policies, e.g., FIT for renewables and renewable targets, on the optimal transmission network expansion when taking into account strategic behavior by GENCOs. Finally, in section 1.3.3 we summarize our findings for the European case.

### 1.3.1 Data Collection

In order to obtain data for the European case, we used different sources of information. We mainly base our model data on the data and scenarios presented in the e-Highway 2050 Project. The e-Highway2050 project was supported by the EU Seventh Framework Programme and was aimed at developing a methodology to support the planning of the Pan-European Transmission Network, focusing on 2020 to 2050, to ensure the reliable delivery of renewable electricity and pan-European market integration (ENTOSOe, 2015). We include some additional information from the ENTSO-E's Ten-Year Network Development Plan (TYNDP) (ENTOSOe, 2014).

This data has already been validated and used in certain publications (Gronau, M.; Dusch, A.; Strunz, n.d.) This data contains several generation technologies such as: wind, solar, hydro, biomass, nuclear, hard coal, lignite, gas, and oil power plants. Additional to these data, we include candidate BESS (technical characteristics, location and costs) and we include detailed information about the evolution of hydro reservoirs (inflows, and reservoir evolution per country), please for more details see Section 1.3.1.5.

### Network

In the e-Highway project a clustering method is applied to reduce the full European Network. The resulting reduced European grid is made of 96 nodes and 112 transmission lines, we consider the EU-28 countries, excluding Malta and Cyprus. We also consider there is at least one node per country. In Figure 9 we present the resulting reduced European network.

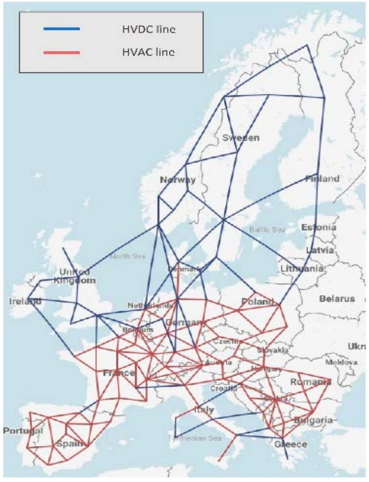

*Figure 9: Reduced European Transmission Network*

### Demand

Similar to the Spanish case we cluster the aggregate data of the European hourly demand data for 2019 into 4 representative days, see Figure 10, additionally for the 2030 demand que consider the same representative days. Please note that this type of aggregation at such a geographical level is intrinsically difficult, given that we try to represent the yearly consumption patterns for 28 different countries by selecting only 4 representative days. We initially tried to cluster the time series considering 28 different dimensions (countries). This multidimensional clustering can be carried out either by normalizing the data or by giving a different weights to each dimension. However, in both cases we obtained some representative days that, when aggregated, resulted in an annual energy consumption 15% to 20% lower than the real data. Therefore we considered the whole European electricity demand, as a single node, and we carried out a single dimension clustering for 4 days. These results lead to 10% underestimation of the total energy consumed, therefore we adjusted weight of each representative day to reach a 100%.

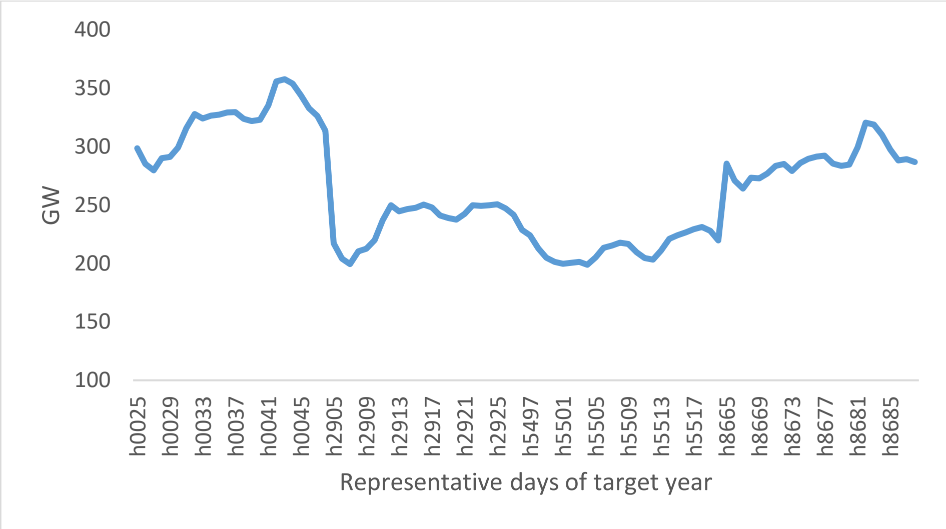


*Figure 10: Hourly European Demand (Representative Days)*

### Annual Production

In order to validate the outputs of our model, we compare the annual energy production for the EU-28 countries for the year 2019 (Agency, 2020). We run the market model for 2019 assuming a cost minimization approach. In Figure 11 we can see that from our model we get similar results the real data, some of the differences could come from the market power exercise in the region. Please note that in the current state of the European system 65% of the energy comes from non-renewable sources and that 38% comes from fossil fuels sources that are the main producers of $CO_2$ emissions in the European Union.

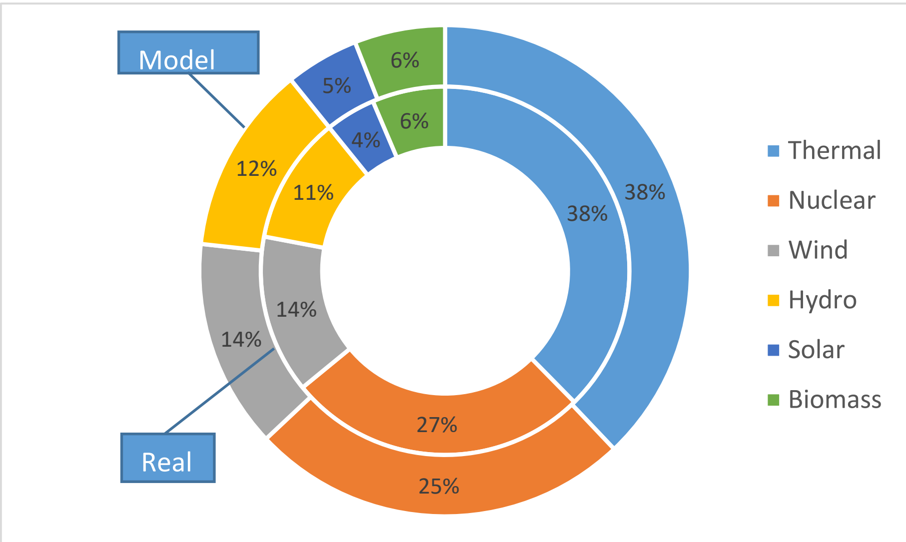


*Figure 11: European Annual Energy Production (Model Results versus Real Production)*

### Candidate Generators

We consider the same technical characteristics of the candidate generators as in Section 1.2.1.5. Additionally, in Figure 12 we can see the type of candidate generators that we consider at each location. Please Note that we consider candidate batteries in most of the locations.


*Figure 12: Location of Candidate Generators in Europe*

### Candidate Lines

Please find the candidate lines in Table VI, we consider 6 candidate lines, they are interconnections among different countries distributed all around Europe.

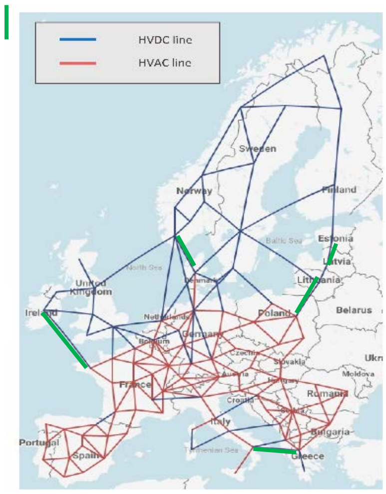


*Table VI: Transmission Lines CAPEX for Europe*

| | | | Reactance (p.u) | Capacity (MW) | Life Time (years) | Total CAPEX k€/MW | Annual CAPEX k€/MW/y |
|---|---|---|---|---|---|---|---|
| **L1** | 21_fr | 96_ie | 0,005 | 1400 | 40 | 1300 | 73 |
| **L2** | 26_fr | 90_uk | 0,009 | 4000 | 40 | 3000 | 169 |
| **L3** | 31_de | 79_no | 0,007 | 2800 | 40 | 2000 | 113 |
| **L4** | 41_pl | 77_lt | 0,011 | 2000 | 40 | 1600 | 90 |
| **L5** | 55_it | 68_gr | 0,004 | 2000 | 40 | 1600 | 90 |
| **L6** | 73_ee | 78_lv | 0,004 | 1900 | 40 | 1500 | 73 |

### Aggregated Hydro Reservoirs

Additionally to the information found in (ENTOSOe, 2015) we include the aggregated evolution of the hydro reservoirs (ENTSOe, 2019), please see Figure 13. From these data we deduct the hydro inflows, we do this estimation by subtracting the hydro production from the hydro reservoir (please note that this is a rough estimation because we disregard spillage). We the use these estimated inflows as inputs that will be taken into account by the model achieve the optimal management of the hydro reservoir, by internalizing the consumption (when pumped hydro is considered) and spillage. Please note that we do not have the information of every country, therefore, for those missing countries, we assign the profile of similar countries, in terms of size and location.

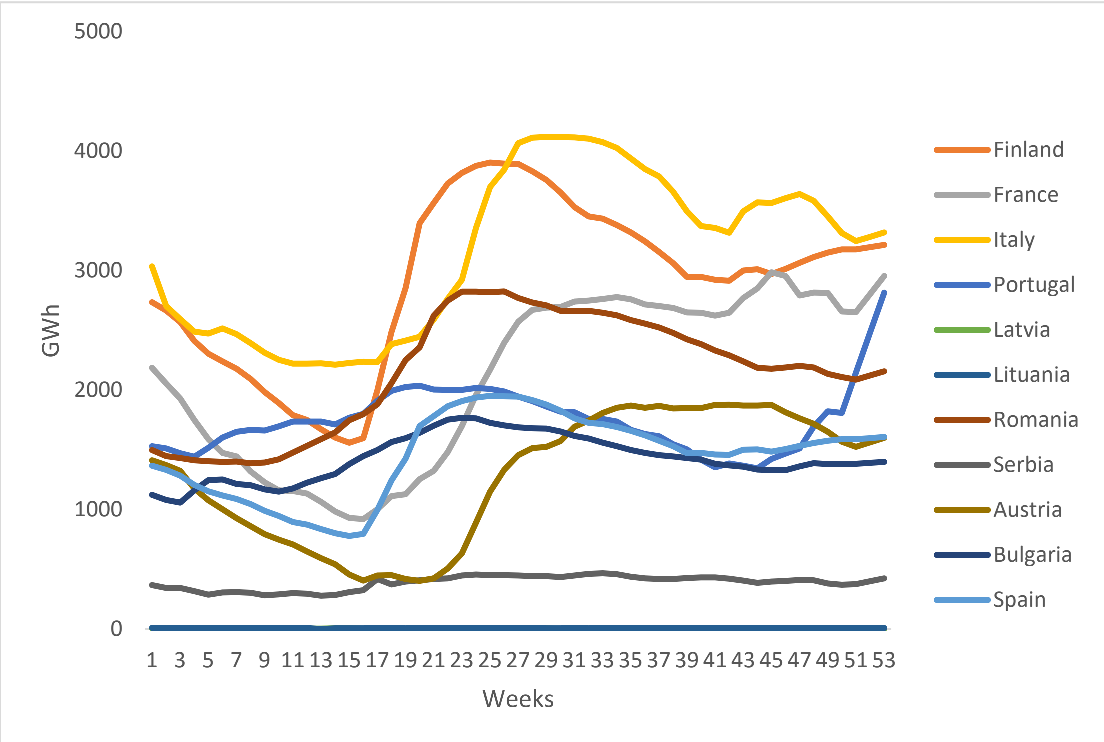


*Figure 13: Weekly hydro reservoir evolution (GWh) for some European Countries 2019*

### 1.3.2 Policy Analysis of the European Case

In this section we present a long-term analysis on how the European power system can be expanded under different policy scenarios. In particular, we study the consequences in the expansion planning of considering imperfect competition in the market. In Section 1.3.2.1 we summarize the methodology and we present the scenarios to be evaluated. In Section 1.3.2.2 we show the results of comparing a centralized planning approach with a proactive one and in Section 1.3.2.3 we expand the results for different scenarios.

#### Climate Policy Scenarios

We consider a modified version of some of the scenarios of the e-Highway project which have a correspondence with those of the TYNDP. Originally, the e-Highway scenarios included different demands forecast for each scenario, however, we consider a unique demand profile forecast for all scenarios, in order to make the comparison among scenarios clearer. Please find a summary in Table VII:

1) Vision 1 - Slowest Progress: Electrification of transport, heating and industry is considered to occur mainly with large scale investments. No flexibility is needed since variable generation from photovoltaic (PV) and wind is low.
2) Vision 2 – Large Scale RES: Focuses on the deployment of large-scale RES technologies. A high priority is given to centralized storage solutions accompanying large-scale RES deployment.
3) Vision 3 – High RES penetration: Based on renewable energy, with both large-scale and small-scale RES technologies. Both large-and small-scale storage technologies are needed to balance the variability in renewable generation.

*Table VII: Policy Scenarios European Case*

| | SCENARIO | DESCRIPTION |
|---|---|---|
| | Slowest Progress | High Gas Prices<br>17 €/ton $CO_2$ price |
| | Large Scale RES | Low Gas Prices<br>71 €/ton $CO_2$ price |
| | High RES penetration | Low Gas Prices<br>76 €/ton $CO_2$ price |

#### Minimum Cost Model vs Equilibrium Model

In this section we present how the generation mix, total cost and total welfare vary if we plan the system according to a traditional cost-min approach instead of a more accurate, proactive planning approach that tackles the strategic behavior of GENCOs.

*Table VIII: Proactive Planning vs Cost-Min Planning Base Case: Europe*

| | Units | Strategic Proactive Planning | Actual Cost-Min Planning |
|---|---|---|---|
| | Lines | L4/L5/L6 | L3/L4 |
| **Total TEP** | GW | 5,9 | 4,8 |
| **Wind** | GW | 48,39 | 48,43 |
| **Solar** | GW | 32,16 | 32,18 |
| **Battery** | GW | 1,20 | 1,20 |
| | GWh | 9,60 | 9,60 |
| **Hydro** | GW | 15,06 | 15,11 |
| | GWh | 60,26 | 60,42 |
| **Nuclear** | GW | 11,29 | 11,18 |
| **Gas** | GW | 7,23 | 7,29 |
| **Hardcoal** | GW | 25,73 | 26,18 |
| **Lignite** | GW | 1,36 | 1,27 |
| **Total GEP** | MW | 142,42 | 142,84 |
| **Total Cost** | M€ | 39,66 | 39,82 |
| **Total SW** | kM€ | 45348,3 | 45348,1 |
| **SW difference** | M€ | | 0,19 € |
| **Regret** | % | | 0,0004% |

As seen in Table VIII, and similar to the Spanish case, the welfare difference between the cost-min case and the proactive case is negligible. However, we can see that there is a significant difference in the generation and transmission investment. In the Proactive Planning approach 3 lines would be built (Estonia-Lithuania, Poland-Latvia, and Italy-Grece), compared to only 2 lines (Denmark-Norway, Poland-Latvia) in the Actual Cost-Min planning. Accounting for strategic market feedback in TEP planning, leads to a more robust transmission network. In particular, under the strategic TEP planning we obtain 2.5GW more in terms of transmission capacity, which represents a 42% distortion in terms of new TEP capacity. Additionally,

This difference in transmission expansion also leads to a small change in the GEP investments per technology that can vary from -6% to 1 %. This means, even if in terms of total welfare these two approaches are similar, in terms of the investments realized, there is a significant impact when ignoring the strategic behavior of GENCOs.

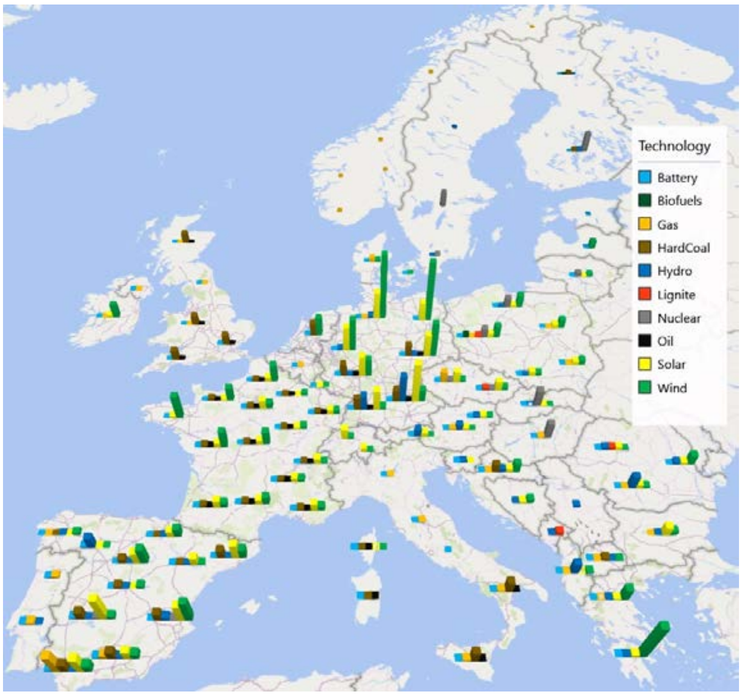


*Figure 14: Location of new GEP investments in the Actual Cost-Min Europe*

In Figure 14 we observe the distribution of the GEP investments following the Actual Cost-Min approach. The height of the bars represents the amount of GW invested in each technology. As we can see, Germany would be the one to present the highest investment in 2030, followed by Spain and France. Solar would be developed all around Europe, in particular it would be heavily invested in Germany and Spain. Wind generation would also be developed in the whole region, particularly in Germany, France and Greece. Hydro power would also play an important role, led by Germany, Spain, Rumania and Albania. Finally, battery investments are very limited, presumably because of its high CAPEX.

### Comparison of Climate Policies

We now compare the results of the Proactive and the Actual Cost min planning in each one of the scenarios described in Section 1.3.2.1.

*Table IX: Scenario Comparison for Proactive Planning vs Cost-Min Planning: Europe*

| | Slowest Progress | | Large-Scale RES | | High RES penetration | |
|---|---|---|---|---|---|---|
| **Units** | **Strategic Proactive Planning** | **Actual Cost-Min Planning** | **Strategic Proactive Planning** | **Actual Cost-Min Planning** | **Strategic Proactive Planning** | **Actual Cost-Min Planning** |
| Lines | L4/L5/L6 | L3/L4 | L1/L2/ L4/L5/L6 | L3/L4 | L1/L2/ L4/L5/L6 | L3/L4 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Total TEP** | GW | 5,9 | 4,8 | 12,7 | 4,8 | 12,7 | 4,8 |
| **Wind** | GW | 48,39 | 48,43 | 83,10 | 81,30 | 89,86 | 88,80 |
| **Solar** | GW | 32,16 | 32,18 | 62,04 | 61,91 | 65,63 | 65,30 |
| **Battery** | GW | 1,20 | 1,20 | 1,32 | 1,31 | 3,31 | 3,67 |
| | GWh | 9,60 | 9,60 | 10,55 | 10,48 | 26,48 | 29,35 |
| **Hydro** | GW | 15,06 | 15,11 | 19,39 | 19,37 | 22,40 | 22,44 |
| | GWh | 60,26 | 60,42 | 77,56 | 77,47 | 89,60 | 89,75 |
| **Nuclear** | GW | 11,29 | 11,18 | 13,06 | 13,03 | 18,12 | 18,43 |
| **Gas** | GW | 7,23 | 7,29 | 10,87 | 11,63 | 14,29 | 14,88 |
| **Hardcoal** | GW | 25,73 | 26,18 | 12,13 | 13,29 | 3,65 | 3,64 |
| **Lignite** | GW | 1,36 | 1,27 | 1,15 | 1,19 | 0,00 | 0,00 |
| **Total GEP** | MW | 142,42 | 142,84 | 203,06 | 203,04 | 217,26 | 217,17 |
| **Total Cost** | kM€ | 39,66 | 39,82 | 42,10 | 42,51 | 45,28 | 46,76 |
| **Total SW** | kM€ | 45348,3 | 45348,1 | 45368,6 | 45368,2 | 45357,1 | 45356,8 |
| **SW difference** | kM€ | | 0,19 | | 0,41 | | 0,36 |
| **Regret** | % | | 0,0004% | | 0,0009% | | 0,0007% |

Table IX shows the results for each policy scenario proposed. We can observe that the total welfare (as well as the total cost) increases with the introduction of more renewable energy. In the Slowest progress, and under the proactive approach, we find that three lines are built, while for the scenarios of higher RES penetration five lines are built. Additionally, the total GEP increases around 5% from the Slowest progress to the Large Scale RES and from the Large Scale RES to the High RES penetration. Please note that for every scenario, the regret is negligible. However, for the Large-Scale RES and High RES penetration, there is a higher difference in the generation and transmission investments.

In the Strategic Proactive Planning we can see that 5 lines are invested compared to the Actual Cost-Min that invests only in two lines. Additionally, this transmission investment implies generation investment variation that go from -2% to 10% in the Large Scale RES scenarios and from -1% to 11% in the High RES penetration. The biggest difference vary for each scenario. For instance, in the Large Scale RES the biggest difference is for hard coal and gas, while for the High RES penetration is for Battery. This could be explain because in the Large Scale RES there is still a high investment in hard coal, which works as a peaking unit that can behave strategically, therefore, we can see a higher difference when we compare it to the actual cost-min problem. In the High RES penetration case, there is a significant investment in batteries compared to the two other scenarios. Additionally, batteries, which are arbitragers by nature, can have a high impact in the system when behaving strategically, and therefore that could explain the 10% decrease that we see from the actual and proactive approaches.

Finally, please also note that for every scenario the same lines are built in the cost-min approach. This suggests that a planning the system under a cost-minimization approach underestimates the profitability of building new lines, by ignoring its impact in the decrease of market power exercise of an imperfectly competitive market. Therefore, independently from the scenarios, the Actual cost-min approach considers that only two new connection lines are sufficient to integrate the new renewables and to minimize total cost, while the proactive approach recognizes that the construction of more lines would increase competition with the possible exports of more renewable generation by diminishing the market power and maximizing the total welfare of the system.

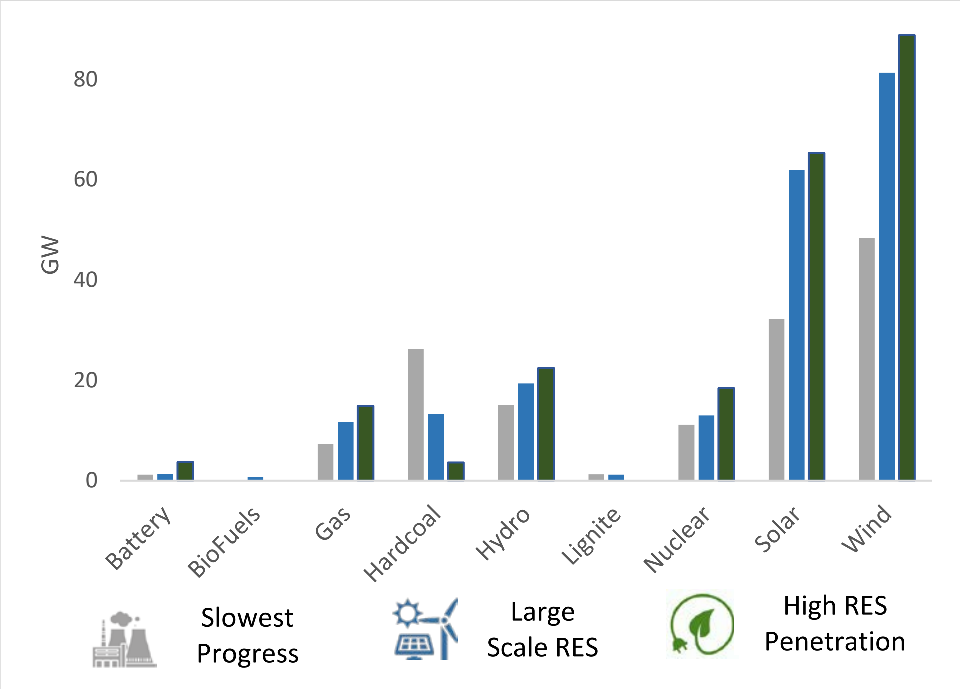


*Figure 15: New installed capacity in Europe*

In Figure 15, we observe total generation capacity in Europe per type of technology. As we can see, in the Slowest Progress case there still a high share of the investments in hard coal, which is the main result of considering low $CO_2$ prices in the future. Moreover, investments in wind and solar in the Slowest Progress are doubled in the Large Scale RES and High RES Penetration scenarios, both because of $CO_2$ prices and the consideration of large scale investments and higher renewable penetration. On the other hand, the investment in Batteries are very low both for the Slowest Progress and Large Scale RES. Only for the High RES Penetration we can see a significant increase in the investment of BESS given the high share of renewables that introduce intermittency to the system. An interesting fact is that Gas, contrary to coal, seems to still have some chance in the evolution of the generation mix but it would be marginal compared to the impact of Solar and Wind.

In order to study these differences in more detail we run a sensitivity analysis to understand the impact of a variation of the Batteries and Hydro CAPEX in the new installed Battery capacity.

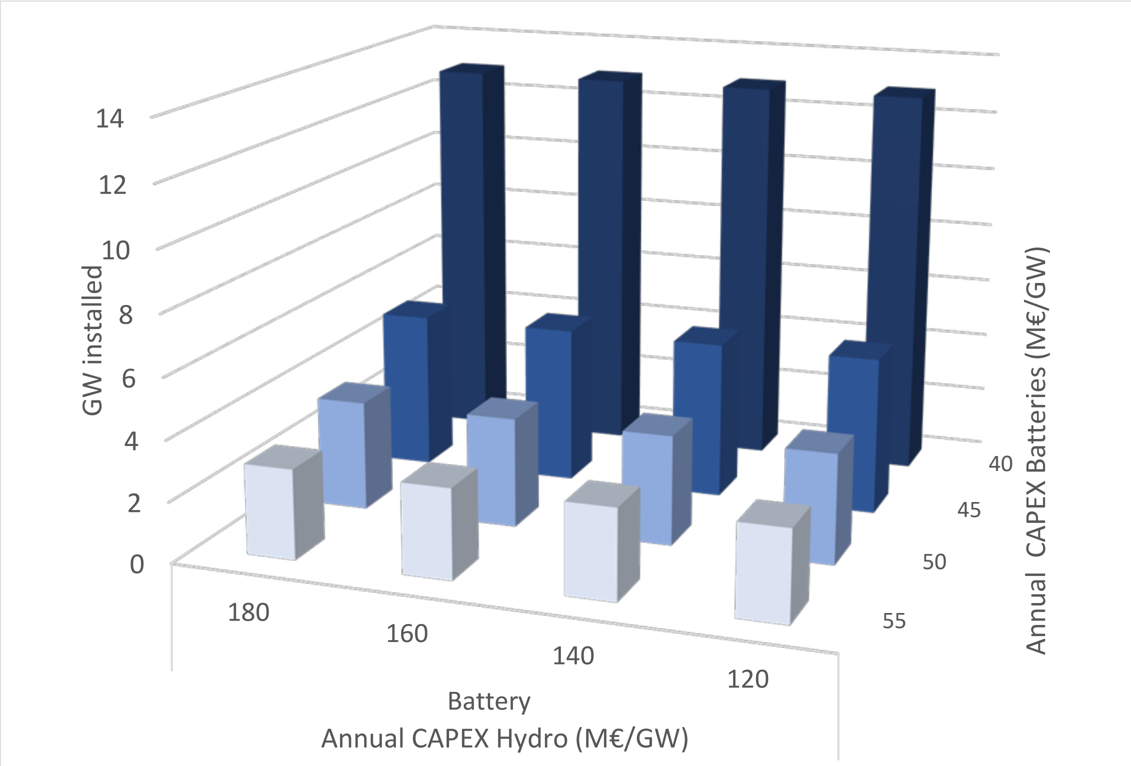


*Figure 16: New GW installed of Batteries: Sensitivity Analysis*

Figure 16 shows that the total GW installed in Batteries are not sensitive to the CAPEX of Hydro units. This suggest that there is not a complementarity, nor substitution effect among these two technologies. However, and as expected, the GW installed in Batteries increases with a decrease in its CAPEX. In fact we can see a breaking point around 40 M€/GW, in which around 12 GW would be installed. Please note that this would correspond to a CAPEX 20% lower than the mean value considered in this report (which was already a low expected CAPEX).

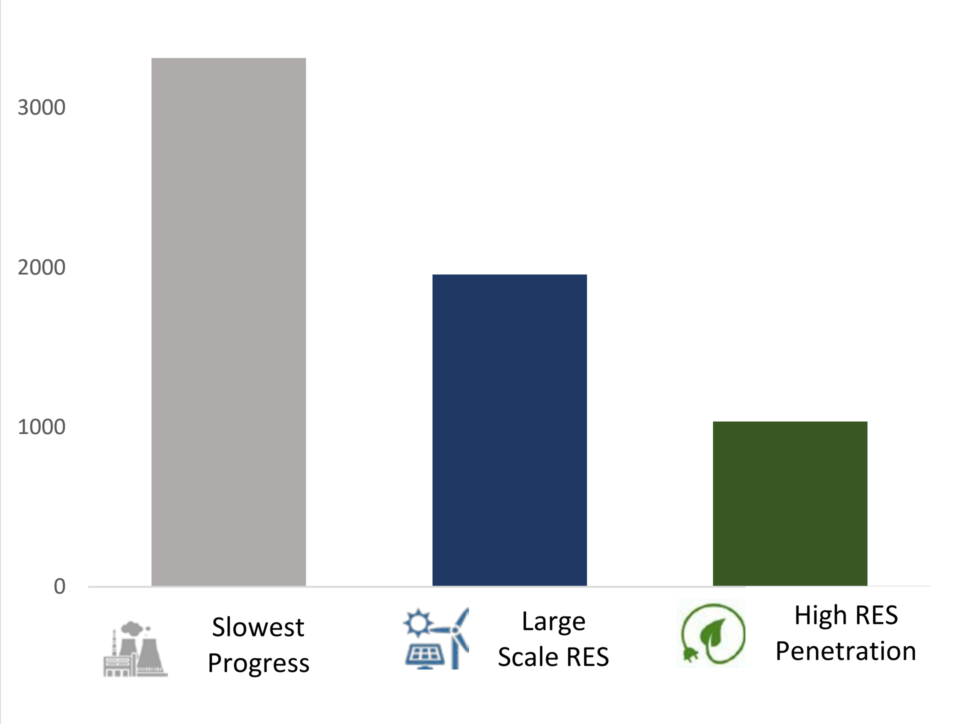


*Figure 17: CO2 Emissions (kton) in Europe*

Finally, in Figure 16 we see that there is a significant decrease in the $CO_2$ emission from the Slowest Progress to the Large Scale policy scenarios, accounting to a 38%. More importantly, compared to the High RES penetration scenarios we see a 68% decrease in the total $CO_2$ emissions, but representing a 20% increase in the total cost of the system.

### 1.3.3 Summary of the European Case

In this section we aimed to measure the effects of considering the strategic behavior of generation companies on the capacity expansion planning of the system, namely, transmission and generation expansion planning. For the European system, which is composed of well-meshed inner-country grids, but not so well interconnected countries, we found that the welfare effects of disregarding the strategic behavior of market agents can amount to the thousands of millions. However, in relative terms to the total welfare, this loss can be considered negligible. Most importantly, we found that beyond the welfare loss, there is a significant impact on the optimal transmission expansion plan. In terms of total GEP investments, the difference also seems negligible; however, there can occur non-negligible differences, ranging from -6 to 11%, in GEP capacity of the different technologies.

Moreover, we found that a Slow Progress scenario would result is an insignificant decrease in the $CO_2$ emissions that would result in the continuation of the climate change crisis. We also tested some more restrictive policies, by increasing a possible price of $CO_2$ emissions, which still leads to some investment in thermal technologies.

Finally, we increased even more the $CO_2$ prices, and we tested a different set of fuel prices. We found that this last scenario would finally lead to a 68% decrease in carbon emission compared the mean scenario likely to happen until 2030, which brings along only a 20% increase in the total costs of the system.

## 1.4 Comparing Scenario-Based Transmission and Generation Expansion Planning Models for Imperfectly Competitive Markets Under Uncertainty

In this section we introduce the stochastic proactive GEPTEP co-planning problem by means a bi-level equilibrium model. This equilibrium (which is convex, because all constraints are linear) is re-formulated as a Mixed Integer Program (MIP), by replacing the lower level equilibrium constraints by its equivalent KKT conditions, and then by linearizing the resulting non-linearities. We present a 24-node case by comparing the deterministic, stochastic and min-max scenario based optimization under perfect and imperfect competition.

### 1.4.1 Notation

*A. Sets / Indices*

| | |
|---|---|
| $y \in Y$ | year |
| $w \in W$ | scenarios |
| $p, \in P$ | periods (hours in the year) |
| $ps \in Ps$ | Moving window periods |
| $rp \in RP$ | representative periods |
| $\Gamma_{rp,p}$ | set of correspondence between $rp$ and $p$ |
| $p$ | final period |
| $d, d' \in D$ | nodes |
| $g \in G$ | generator unit $g$ |
| $t(g) \in T$ | thermal units |
| $h(g) \in H$ | storage units |
| $hf(h) \in HF$ | fast short-term storage units (batteries) |
| $hs(h) \in HS$ | slow long-term storage units (hydro) |

| | |
|---|---|
| $GAD(g,d)$ | set of all possible *g* located at node *d* |
| $GED(g,d)$ | set of existing g located at node *d* |
| $GCD(g,d)$ | set of candidate g located at node *d* |
| $LA(d,d')$ | set of all possible lines from node *d* to *d'* |
| $LE(d,d')$ | set of existing lines from node *d* to *d'* |
| $LC(d,d')$ | set of candidate lines from node *d* to *d'* |
| $Hpp'$ | Univocal correspondence between period *p* and *p'* ∈ $\Gamma_{rp,p}$ |

*B. Parameters*

| | | |
|---|---|---|
| $pMaxProd_g$ | Maximum capacity of technology $g$ | MW |
| $pMaxFlows_{dd'}$ | Maximum flow in line *dd'* | MW |
| $pReactance_{dd'}$ | Reactance of line *dd'* | [p.u] |
| $pFCost_t$ | Fuel cost of technology $t$ | €/MWh |
| $pFixCost_t$ | Fix operation cost of thermal generator | € |
| $pInvC_g$ | Annualized investment cost $g$ | €/MW |
| $pInvC_{dd'}$ | Annualized investment cost of line *dd'* | € |
| $pDemand_{ypd}$ | Demand Intercept at year *y* period $p$ at node $d$ | MW |
| $pDSlope$ | Demand Slope | €/MW |
| $pEfficiency_h$ | Efficiency of storage unit *h* | [p.u] |
| $pInfl_{yphsd}$ | Energy inflows for year *y* period *p* storage *hs* at node d | MWh |
| $pMaxLevel_h$ | Max/Min reservoir level of storage unit *h* | MW |
| $pMinLevel_h$ | | |
| $pMaxCons_h$ | Maximum consumption of storage unit | MW |
| $M$ | Time window | h |
| $pW_{rp}$ | Weight of each representative day | [p.u] |

| | | |
|---|---|---|
| $pSB$ | Base Power | MW |
| $\theta_g$ | Conjectural variation of GENCO g | €/MW |

*C. Variables*

| | | |
|---|---|---|
| $vProd_{ywpgd}$ | Production at year $y$ scenario w period $p$ of generator $g$ at node *d* | MW |
| $vNewGen_{ygd}$ | Investment status at year $y$ of generation unit g at node d | {0,1}/MW |
| $vNewLine_{ydd'}$ | Investment status at year $y$ of line connecting node $d$ to $d'$ | {0,1}/MW |
| $vFlows_{ywpdd'}$ | Flows at year $y$ scenario w at period $p$ from node *d* to *d'* | MW |
| $vTheta_{ywpd}$ | Voltage angle at year y scenario w period p node *d* | p.u. |
| $vDemand_{ywpd}$ | Demand at year y scenario w period $p$ at $d$ | MW |
| $vLevel_{ywphd}$ | Level at year $y$ scenario w period $p$ of storage unit h at node $d$ | MW |
| $vConw_{yphd}$ | Consumption at year $y$scenario w period $p$ of storage unit h at node $d$ | MW |
| $vSpill_{ywphd}$ | Spillage at year $y$ scenario w period $p$ of storage unit *h* at node $d$ | MW |
| $\lambda_{\text{ypd}}$ | Prices at year *y* scenario w period *p* node *d* | €/MW |

### 1.4.2 Model Description

Before presenting the formulation of the bi-level model, we first explain the market responsive framework to be used in the lower level. Then, we introduce the Bi-level Proactive Model (PM).

#### Market Responsive Framework

Following the work of [24], we consider an affine relation between prices and demand as shown in (105), i.e., demand is elastic, where *pDemand* represents the inelastic part of the demand and *pDslope* represents the slope of this function, which can be interpreted as how demand reacts to prices. Therefore, for a given node and period the demand would be given by (1).

$$vDemand_d = pDemand_d - pDslope_d * \lambda_d \; \forall d \qquad (1).$$

We furthermore define a conjectural variation $\theta_g = \partial\lambda_d/\partial vProd_g$ that is assumed to be known for every GENCO $g$ . This conjecture corresponds to each GENCO's belief on how much they can impact market prices by varying its production $vProd_g$ (or $vCon_h$ for storage units). If $\theta_g = 0$ this represents perfect competition (PC), and if $\theta_g = 1/pDSlope$ (inverse of the slope of the residual demand curve) it represents the Cournot oligopoly (CO). This conjecture allows us to model different degrees of competitive behavior.

#### Deterministic Bi-level Proactive Model (DPM)

We present the proactive framework in which a social planner TSO - which can be understood as an entity where both TSO and regulator are considered together - (from now on TSO) proposes investments and GENCOs react to its decisions. Figure 40 shows the bi-level framework, where the TSO takes TEP decisions in the upper level subject to the lower level. Likewise, the lower level represents the market equilibrium where GENCOs take GEP and operating decisions, while the system operator (SO) makes sure that the power flow decisions are feasible.

<table>
<tr><td>Upper Level</td><td colspan="3">TSO or social planner<br>(decides TEP)<br>Maximizes Welfare</td></tr>
<tr><td rowspan="2">Lower Level</td><td>GENCOs<br>(decide GEP and operation)<br>Maximize Benefits</td><td>SO<br>(decides power flow)<br>Maximizes Congestion Rents</td><td>Consumers<br>(decide demand)<br>Maximize Demand Utility</td></tr>
<tr><td colspan="3">Market Clearing Condition</td></tr>
</table>

***Figure 18: Bi-level Framework.***

### Stochastic Bi-level Proactive Model (SPM)

Please note that in Section 2 we consider that investment and operation are taken simultaneously in the lower level. This model, known as an open loop capacity equilibria, can render the same results as a close loop model (generation decisions first and then operation) only under certain conditions [13]. Even though the close loop equilibria is a more general framework, that considers the sequence between generation investment and operation, it leads to a more complex and intractable model. Therefore, in order to overcome the simplifications made by the open loop capacity equilibria we consider a two-stage stochastic generation expansion model in the lower level, which in turn leads to a stochastic proactive bilevel model, please see Figure 41.

We simplify the operation in the whole year by considering four representative days. Accordingly, we consider different wind profiles for each representative day, this implies considering daily the variability of wind along the year. However, wind can variate from year to year up to 20% from the mean (for the U.S western system), as seen from historical times series. Therefore, for each profile in each representative day we consider three scenarios (w), low, mean and high scenarios, which are 20% higher and lower respectively, in terms of energy, compared to the mean.

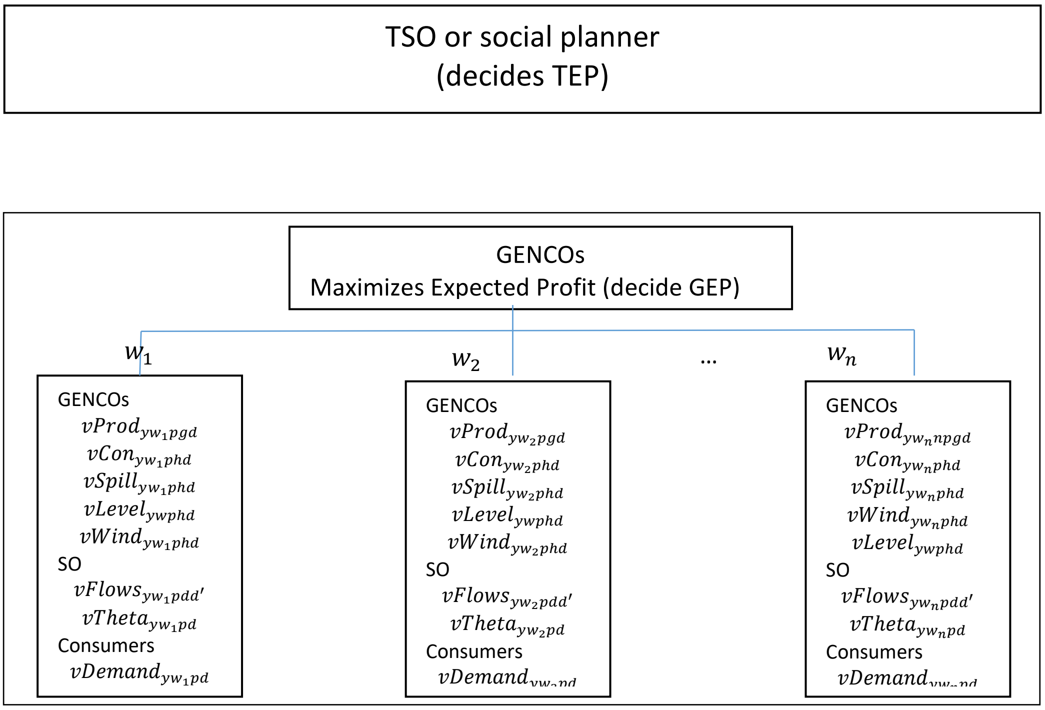


***Figure 19: Stochastic Bi-level Framework***

**Upper Level: TEP**

The social planner TSO aims at maximizing the total expected welfare, computed as the Utility of the Demand (UD) minus total costs. This objective is represented by (4), where central planner TSO minimizes the Total Cost (TC) composed by Line Investment Costs (LI), Generation Investment Costs (GI), and Operation Cost (OC). Therefore, the actual objective function would be given by (114). Note that we do not allow for de-investment as imposed by equations (117) and (118). Equation (115) represents the utility of demand resulting from the area under the demand curve.

| | |
|---|---|
| $\underset{vNewLineydd'}{\text{Maximize}} \; UD - (OC + LI + GI)$ | (2) |

Subject to (115) - (119), and Lower Level equilibrium

$$UD := \sum_{y,w,(p,rp)\in\Gamma_{rp,p},d} pProb_w * pW_{rp} * \left( pDemand_{ypd} * vDemand_{ywpd} - \frac{vDemand_{ywpd}^{\;2}}{2} \right) \quad (3)$$

$$OC := \sum_{y,w,(p,rp)\in\Gamma_{rp,p},t,d} pProb_w * pW_{rp} * pFCost_t * vProd_{yptd} \quad (4)$$

$$LI := \sum_{ydd'} (Y - y + 1) * pInvL_{dd'} * \left( vNewLine_{ydd'} - vNewLine_{y-1,dd'} \right) \quad (5)$$

$$GI := \sum_{gyd} (Y - y + 1) * pInvC_g * \left( vNewGen_{ygd} - vNewGen_{y-1,gd} \right) \quad (6)$$

$$vNewLine_{y-1,dd'} \leq vNewLine_{ydd'} \; \forall (d,d') \in LC \; \forall y \quad (7)$$

### Lower Level: market equilibrium

The lower level represents the market equilibrium where consumers maximize the utility of the demand, GENCOs maximize their profits (deciding generation investment and operation of generating assets) and a SO maximize congestions rents (deciding power flows and voltage angles). The consumers, GENCOs and SO's optimization problems are linked by the market clearing condition (78). This market structure implies that GENCOs do not anticipate market outcome in their expansion decisions. However, as mention before, by introducing a two-stage stochastic model we are able to decide generation investment by considering different possible operation scenarios. Additionally, since we are able to adapt the degree of competition in the market in our model, choosing a less competitive market might "compensate" for this non-anticipation [25]. The previous description implies that the market is modeled as a spatial equilibrium model where GENCOs compete strategically and react naively to the transmission congestions as in [26]. Additionally, we assume that there is only one GENCO per node, but we might have several generation units per GENCO.

Moreover, in the formulation of the market model we use enhanced representative days [18] to represent the temporal structure. The novelty of this temporal representation is that it allows us to capture both short- and long-term storage technologies accurately due to the intra- and inter-day storage constraints, which are explained in detail in [18] and upon which we comment briefly later on. From now on, each equation is defined for $p \in \Gamma_{rp,p}$.(except (14)). Please note that $\Gamma_{rp,p}$ indicates which hours, from the whole year, belong to each representative day.

#### Consumer: Demand Utility maximization

The consumers try to maximize the utility of the demand, by deciding demand. Their optimization problem is given by:

$$Max_{vDemand_{ywpd}}\, UD$$

Subject to (115) and (120)

$$vDemand_{y,w,p,d} \geq 0 \; \forall ywpd : \iota_{y,w,p,d} \qquad (8)$$

#### GENCO: Profit Maximization Problem

$$arg\; \underset{GV}{\text{Maximize}}\, Profit = OI - OC - GI \qquad (9)$$

Subject to (116),(118), (122) - (14).

$$GV: \{vNewGen_{ygd}, vProd_{ywpgd}, vProd_{ywpgd}, vCon_{ywphd}, vSpill_{ywphd}\} \quad (10)$$

$$OI := \sum_{y,p,rp,g,d} pProb_w * pW_{rp} * (\lambda_{ywpd}) * (vProd_{ywp,gd\in GAD} - vCon_{ywp,hd\in GAD}) \quad (11)$$

$$0 \leq vProd_{ywpgd} \leq pMaxProd_g \quad : \bar{\rho}_{ywpgd}, \underline{\rho}_{ywpgd} \quad \forall ywp, \forall gd \in GED \quad (12)$$

$$0 \leq vProd_{ywpgd} \leq pMaxProd_g * vNewGen_{ywgd} \quad : \bar{\omega}_{ywpgd}, \underline{\omega}_{ywpgd} \quad \forall ywp, \forall gd \in GCD \quad (13)$$

$$0 \leq vWind_{ywpgd} \leq pMaxWind_{pwgd} \quad : \overline{\rho w}_{ywngd}, \underline{\rho w}_{ywpgd} \quad \forall ywp, \forall gd \in GED \quad (14)$$

$$0 \leq vWind_{ywpgd} \leq pMaxWind_{pwgd} * vNewGen_{ygd} \quad : \overline{\omega w}_{ywpgd}, \underline{\omega w}_{ywpgd} \quad \forall ywp, \forall gd \in GCD \quad (15)$$

$$pMinLevel_h \leq vLevel_{ywphd} \leq pMaxLevel_h \quad : \overline{\mu e}_{ywphd}, \underline{\mu e}_{ywphd} \quad \forall ywp, \forall hd \in GED \quad (16)$$

$$0 \leq vLevel_{ywphd} \leq pMaxLevel_h * vNewGen_{yhd} \quad : \overline{\mu c}_{ywphd}, \underline{\mu c}_{ywphd} \quad \forall ywp, \forall hd \in GCD \quad (17)$$

$$0 \leq \frac{vCon_{ywphd}}{pEfficiency_h} \leq pMaxCons_h \quad : \overline{\kappa e}_{ywphd}, \underline{\kappa e}_{ywphd} \quad \forall ywp, \forall hd \in GED \quad (18)$$

$$0 \leq \frac{vCon_{ywphd}}{pEfficiency_h} \leq pMaxLevel_h * ETD * vNewGen_{yhd} \quad : \overline{\kappa c}_{ywphd}, \underline{\kappa c}_{ywphd} \quad \forall ywp, \forall hd \in GCD \quad (19)$$

$$-vNewGen_{y-1,gd} + vNewGen_{ygd} \geq 0 \quad : \underline{\beta}_{ygd} \quad \forall y, \forall gd \in GCD \quad (20)$$

$$0 \geq -vNewGen_{ygd}; 0 \leq MaxGen_g - vNewGen_{ygd} \quad : \bar{o}_{ygd}, \underline{o}_{ygd} \quad \forall yw, \forall gd \in GCD \quad (21)$$

$$0 \leq vSpill_{ypwhd} \quad \forall yp, \forall hd \in GAD \quad (22)$$

$$vLevel_{ywph_fd} = vLevel_{y,w,p-1,hf,d} + pIniLevel_{y=1,w,p=1,hf,d} - vProd_{ywph_fd} + vCon_{ywph_fd}$$
$$: \psi_{ywphd} \quad \forall h_f d \in GAD, \forall ywp, p < pf \quad (23)$$

$$vLevel_{ywphsd} = vLevel_{y,w,p-M,hs,d} + pIniLevel_{y=1,p=1,hs,d} + \sum_{p'}^{p} \sum_{p''} (pInfl_{ywp''hsd} - vSpill_{ywp''hsd} - vProd_{ywp''hsd} + vCon_{ywp''hsd}) \quad (24)$$
$$: \psi'_{ywphd} \quad \forall yw, \forall hs, d \in GAD, \forall p, p < pf$$

$$with\ p` = p - M + 1\ and\ p \in Ps, p'' \in H(p', p'')\ \ Ps = \left\{ps | \frac{ps}{M} \in Z^+\right\}$$

Equation (59) represents the expected operational incomes of GENCOs, equations (60),(126), (130), (68) and (69) represent upper and lower bounds of the existing elements of the system. While equations (62), (15), (65) and (129) represent the lower and upper bounds of the candidate generation investments in the system. Equation (132) avoids de-investments and (67) defines the non-negativity of new generation. Finally, equations (13) and (14) represent the storage balance conditions as proposed in [18].

On the one hand, equation (14) is considered for long-term storage, i.e. hydro, where only interday balance is considered. In this equation, reservoir management is followed up across the entire year, as opposed to the rest of constraints in which only intraday operations are included. For the hydro vCon represents pumping decisions and vProd the production decisions. On the other hand, equation (13) is considered to represent short-term storage when intraday operation is relevant, i.e. batteries. Variables vCon and vProd represent charging and discharging. While the detailed formulation and explanation of this representation of storage is presented in [18], we briefly explain it here for clarity.

The reservoir energy balance is verified for a given time window. For instance, consider 4 representative periods, a 168 hour (one week) window and two weeks as shown in Figure 42. Thus, the reservoir balance equation (20) will be verified at the end of every week e.g. at M1 and M2. Thus, the interday balance is the sum of inflows and consumption minus spillage and production for every "representative hour" (p''), which represents each hour of the year (p'). In addition, they are summed over the window M until hour ($p \in Ps$). Please note that $H(p'', p')$ maps each hour of the year to its corresponding hour in the appropriate representative day (i.e the first 24 hours of the year can be represented by hours 5545-5568 of RP4), and is not to be confused with $\Gamma_{rp,p}$ that tells us which hours of the year are the representative ones (i.e RP4 is made of hours 5545-5568).

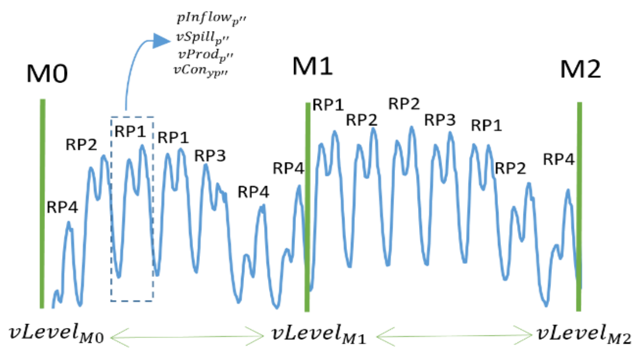


Figure 20: Interday Energy Balance.

### SO

We assume that the SO wants to maximize congestions rents from price differences by deciding power flows.

$$arg \underset{vFlows_{ywpdd'}, vTheta_{ywpd}}{\text{Maximize}} CongestionRents = \sum_{y,p,d} (\lambda_{ywpd} - \lambda_{ywpd'}) * vFlows_{ywpd'd}$$

Subject to (72)-(77), where

$$pMaxFlows_{dd'} \geq vFlows_{ywpdd'} \geq -pMaxFlows_{dd'} \quad : \bar{\phi}_{ywpdd'}, \underline{\phi}_{ywpdd'} \forall ywp, \forall (d,d') \in LE \tag{25}$$

$$vFlows_{ywpdd'} = pSB * \frac{vTheta_{ywpd} - vThetha_{ywpd'}}{pReactance_{dd'}} \quad : \phi_{ywpdd'} \quad \forall ywp, \forall (d,d') \in LE \tag{26}$$

$$vFlows_{ywpdd'} \geq -pMaxFlows_{dd'} * vNewLine_{ywdd'} \quad : \underline{\zeta}_{ywpdd'} \quad \forall ywp, \forall (d,d') \in LC \tag{27}$$

$$-vFlows_{ywpdd'} \geq -(\ pMaxFlows_{dd'} * \ vNewLine_{ywdd'}) \quad : \bar{\zeta}_{ywpdd'} \quad \forall ywp, \forall (d,d') \in LC \tag{28}$$

$$-vFlows_{ywpdd'} \geq \left(-pSB * \frac{vTheta_{ywpd} - vThetha_{ywpd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ywdd'})\right) \quad : \bar{\tau}_{ywpdd'} \quad \forall ywp, \forall (d,d') \in LC \tag{29}$$

$$vFlows_{ywpdd'} \geq \left( pSB * \frac{vTheta_{ywpd} - vThetha_{ywpd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ydd'})\right) \quad : \underline{\tau}_{ywpdd'} \quad \forall ywp, \forall (d,d') \in LC \tag{30}$$

Equations (72) and (73) represent the DC formulation of the network for existing lines, while equations (74)-(77) represent the DC power flow formulations for new lines.

### Market Clearing

$$\sum_{g \epsilon GAD} vProd_{ypwgd} + \sum_{g \epsilon GAD} vWind_{ywpgd} + \sum_{d' \epsilon LA} vFlows_{ywpdd'} - \sum_{d' \epsilon LA} vFlows_{ywpd'd} : + \sum_{h \epsilon GAD} \frac{vCon_{ywphd}}{pEfficiency_h} = vDemand_{ywpd} \quad : \lambda_{ypd} \ \forall y, w, p, d \tag{31}$$

The simultaneous consideration of the GENCOs, Consumers, SO, and market clearing condition represent the wholesale market for the case of perfect and imperfect competition (depending on the conjectural variation described in 4.1.1). Additionally, we implement a regularization method to compute Big Ms as proposed in [27].

### KKT Conditions

An equivalent formulation for the lower level optimization problem is presented. KKT conditions are the following:

Primal feasibility conditions. SO: (72) - (78) and Gencos: (60) - (14)

Dual feasibility conditions. SO: (79) - (80) and Gencos: (81) - (87)

- Complementary slackness conditions[6]

Dual feasibility conditions: (Each equation is defined for $p \in \Gamma_{rp,p}$, except for equations

(83) to (87)

$$\begin{aligned}\lambda_{ywpd'} - \lambda_{ywpd} + \underline{\phi}_{ywpdd' \in LE(d,d')} - \bar{\phi}_{ywpdd' \in LE(d,d')} + \phi_{ywpdd' \in LE(d,d')} \\ + \underline{\zeta}_{ywpdd' \in LC(d,d')} - \bar{\zeta}_{ywpdd' \in LC(d,d')} + \bar{\tau}_{ywpdd' \in LC(d,d')} \\ - \underline{\tau}_{ywpdd' \in LC(d,d')} = 0 : vFlows_{ywpdd'} \ \forall ywpdd'\end{aligned} \tag{32}$$

$$\begin{aligned}\sum_{d \in LE(d,d')} \frac{pSB}{pReactance_{dd'}} * \phi_{ywpdd'} - \sum_{d' \in LE(d,d')} \frac{pSB}{pReactance_{d'd}} * \phi_{ywpd'd} \\ + \sum_{d \in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \bar{\tau}_{ywpdd'} \\ - \sum_{d' \in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \underline{\tau}_{ywpd'd} \\ - \sum_{d' \in LC(d',d)} \frac{pSB}{pReactance_{d'd}} * \bar{\tau}_{ywpd'd} \\ + \sum_{d \in LC(d,d')} \frac{pSB}{pReactance_{d'd}} * \underline{\tau}_{ywpdd'} = 0 : \ vTheta_{ywpd}, \forall ywpd\end{aligned} \tag{33}$$

[6] Linearized conditions can be found in ANNEX

$$\sum_{gyd}(Y-y+1)*pInvC_g+\sum_{gyd}(Y-y)*pInvC_g+pMaxProd_g*\bar{\omega}_{ypgd} + pMaxWind_{pwgd}*\overline{\omega W}_{ywpgd}+pMaxLevel_h*\overline{\mu c}_{ywphd}+pMaxLevel_h*ETD * \overline{\kappa c}_{ywphd}+\underline{\beta}_{ygd}-\underline{\beta}_{y+1,gd}-\bar{o}_{ygd}+\underline{o}_{ygd} = 0 \quad : vNewGen_{ygd}\ \forall ygd\in GCD \tag{34}$$

$$-vDemand_{ypd}+pDemand_d-pDSlope*vProd_{ywpgd}=0 \tag{35}$$

$$\iota_{y,w,p,d}: vDemand_{ywpd}\ \forall ywgd\in GAD$$

For equations

(83) to (87) we define $p''=p'+1-M\ Pa=\{p|p\ \in\Gamma_{rp,p}\},\ Ps=\left\{ps|\frac{ps}{M}\in Z^+\right\},$ $and\ Pt=Ps\cup\ Pa$

$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p},d} pProb_w*pW_{rp}*(-FuelCost_t+vProd_{ywpgd} * \frac{\partial\lambda_{ywpd\in(GAD)}}{\partial vProd_{ywpgd}}+)\right)+\lambda_{ywpd\in(GAD)}-\bar{\rho}_{ywpgd\in(GED)} + \underline{\rho}_{ywpgd\in(GED)}-\bar{\omega}_{ywpgd\in(GCD)}+\underline{\omega}_{ywpgd\in(GED)}+\sum\nolimits_{p''}^{p'}(\psi_{yph}) = 0 \tag{36}$$

$$: vProd_{ywpgd}\quad \forall y,g,d\in\ (GED)\ \forall p'\in H(p',p)\ /\ \ p\in Pa,\ p'\in\ Ps$$

$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p},d} pProb_w*pW_{rp}*(\,vWind_{ywpgd}*\frac{\partial\lambda_{ywpd\in(GAD)}}{\partial vWind_{ywpgd}}+)\right) +\lambda_{ywpd\in(GAD)}-\overline{\rho w}_{ywpgd\in(GED)}+\underline{\rho w}_{ywpgd\in(GED)} -\overline{\omega w}_{ywpgd\in(GCD)}+\underline{\omega w}_{ywpgd\in(GED)}+\sum\nolimits_{p''}^{p'}(\psi_{yph})=0 \tag{37}$$

$$: vWind_{ywpgd}\quad \forall y,g,d\in\ (GED)\ \forall p'\in H(p',p)\ /\ \ p\in Pa,\ p'\in\ Ps$$

$$\bar{\kappa}_{ywphd} - \underline{\kappa}_{ywgphd} + \psi_{ywph_fd} + \sum_{p''}^{p'} \left(\psi'_{ywphd}\right) = 0$$

$$: vCon_{ywphd} \quad \forall p' \in H(p', p), p \in Pa,\ p' \in\ Ps, \forall yw, hd \in\ (GED) \tag{38}$$

$$-\bar{\mu}_{yphd} + \underline{\mu}_{yphd} + \sum_{p''}^{p'} \psi_{ywphd} = 0$$

$$: vSpill_{ywphd} \quad \forall p' \in H(p', p)\ \ p \in Pa,\ p' \in\ Ps, \forall yw, hd \in\ (GED) \tag{39}$$

$$-\overline{\mu e}_{ywphd} + \underline{\mu e}_{ywphd} - \overline{\mu c}_{ywphd} + \underline{\mu c}_{ywphd} + \psi_{ywp\in Pa,h_fd} + \psi_{yw,p+1\in Pa,h_fd} + \psi'_{ywp\in Ps,hd} - \psi'_{yw,p+M|p\in Ps\ ,hd} = 0 \tag{40}$$

$$: vLevel_{ywphd} \forall p \in Pt, \forall ywhd \in GED$$

**Equivalent Optimization problem**

The KKT conditions in section 0 can also be written as an optimization problem by following the results of [28]. This optimization problem would be equivalent to minimizing the Extended Social Welfare and can be written as follows:

$$\underset{LLV}{\text{Minimize}}\, ESW = GI + OC + EC - UD \tag{41}$$

- *Subject to* ***(60) - (78) (154) - (159)***

$$LLV := \{vNewGen_{ygd}, vWind_{ywpgd}, vProd_{ywpgd}, vCon_{ywphd}, vSpill_{ywphd}, vFlows_{ywpdd'}, vTheta_{ywpd}\} \tag{42}$$

$$UD := \sum_{y,w,(p,rp)\in\Gamma_{rp,p},d} pProb_w * pW_{rp} * \left(pDemand_{ypd} * vDemand_{ywpd} - \frac{vDemand_{ywpd}{}^2}{2}\right) \tag{43}$$

$$EC := \sum_{y,w,(p,rp)\in\Gamma_{rp,p},t,d} pProb_w * pW_{rp} * \theta_g * \left(vProd_{ywp,gd\in GAD} - vCon_{ywp,hd\in GAD}\right)^2 \tag{44}$$

$$OC := \sum_{y,w,(p,rp)\in\Gamma_{rp,p},t,d} pProb_w * pW_{rp} * pFCost_t * vProd_{yptd} \tag{45}$$

$$LI := \sum_{ydd'} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \tag{46}$$

$$GI := \sum_{gyd} (Y - y + 1) * pInvC_g * \left(vNewGen_{ygd} - vNewGen_{y-1,gd}\right) \tag{47}$$

As we can see the objective function is the same as a welfare maximization problem but it additionally includes EC which reflects the strategic behavior of agents by the conjectural variation $\theta_g$.

### Min-Max Regret Proactive Model (RPM)

We now compute a type of robust programing that considers the degree of robustness in the objective function. In this section we consider the min-max regret programming, this is an adjusted technique that is less conservative than the min-max programming where the system is planned against the worst case scenario. On the contrary, this framework tries to minimize the maximum regret of the solution in any operational scenario. We consider define the lower level and upper level min-max regret programming.

### Lower Level Min-Max Regret (LLR)

We consider the min-max regret in the lower-level. Therefore, the regret is considered as the difference between the total Extended Social Welfare (defined in (40)) at each scenario $ESW_s$ and the perfect information optimal solution $ESW^*_s$ of that scenario. By the perfect information solution scenario *s* we mean the solution of the Deterministic Proactive Model (DPM) when it is considered that only that scenario s will occur (i.e., *pProb(s)*=1). Compared to the stochastic approach, in this methodology we do not need to have a probability distribution of the scenarios.

$$\underset{LVV}{\text{Minimize}} \quad GI + \underset{s}{\text{Maximize}}(\, OC + EC - \; UD - ESW^*{}_s) \tag{48}$$

Problem **(160)** can be transform by adding the auxiliary variable $\varsigma$ and the set of equation **(162)**:

$$\underset{LVV}{\text{Minimize}} \quad GI + \varsigma \tag{49}$$

S.t and LL

$$OC + EC - \; UD - ESW^*{}_s \leq \varsigma \; \forall \; s \in S \tag{50}$$

**Complete Problem with Lower Level Min-Max Regret**

In the complete problem, the upper level would be constrained by the LLR defined in previous section.

$$\underset{vNewLineydd'}{\text{Minimize}} \; -(UD - (OC + LI + GI)) \tag{51}$$

s.t LLR

$$\underset{LVV}{\text{Minimize}} \quad GI + \varsigma \tag{52}$$

S.t (53) and LL

$$OC + EC - \; UD - ESW^*{}_s \leq \varsigma \; \forall \; s \in S \tag{53}$$

**Upper level Min-Max Regret (ULR)**

We consider the min-max regret in the lower-level. To do so, we follow the same logic in 0.Therefore, the regret is considered as the difference between the total Social Welfare (defined in (2)) at each scenario $SW_s$ and the perfect information optimal solution $SW^*{}_s$ of that scenario.

$$\underset{vNewLineydd'}{\text{Minimize}} -(+LI + GI) + \underset{s}{\text{Maximize}}( OC - UD - SW^*{}_s)$$

**Complete Problem with Upper Level Regret**

$$\underset{LVV}{\text{Minimize}} -(+LI + GI) + \varsigma \tag{54}$$

S.t **(167)** and LL

$$OC - UD - SW^*{}_s \leq \varsigma \; \forall\, s \in S \tag{55}$$

### 1.4.3 Case Study

In order to test this model we consider a IEEE-24 modified system as the one considered in [10]. As seen in **Figure 40** this system is made up of 24 buses, 33 existing lines, and 12 existing conventional generators. Continuous lines represent existing elements and dotes lines represent candidates lines. We consider 3 candidate conventional generators at nodes 3, 10, and 19, as well as 6 wind candidate generators at nodes 3,5,7, 16,21,23. Additionally, we consider 4 candidate batteries at nodes 1, 3 ,15 and 1 hydro candidate at node 19.

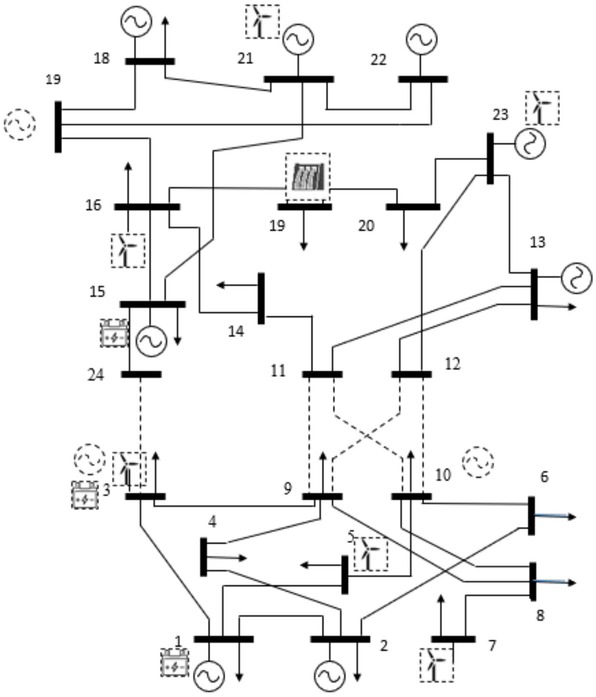

*Figure 21: IEEE-24*

We consider 4 representative days and 3 wind profiles scenarios for each wind candidate generator. We consider different profiles for the wind generator located at the south (nodes 3,5,7), as seen in Figure 44: Southern Normalized wind profiles per GeneratorFigure 44, and some other profiles for those located in the north (nodes 16,21,23) as seen in Figure 45.

We consider the following probabilities for the scenarios:

*Table X: Scenarios Probability*

| S1 | S2 | S3 |
|---|---|---|
| 0.24 | 0.38 | 0.38 |

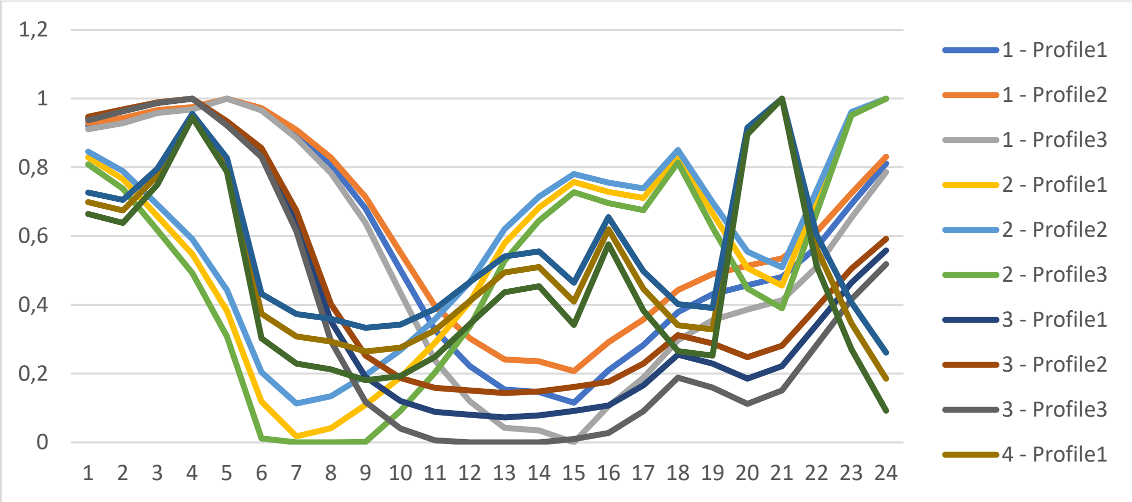


*Figure 22: Southern Normalized wind profiles per Generator*

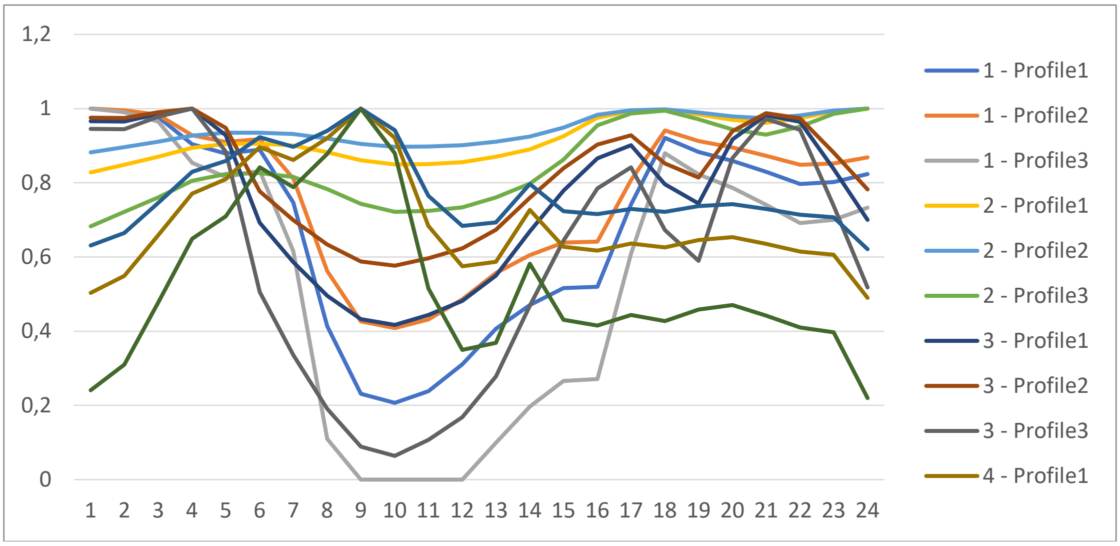


*Figure 23: Northern Normalized wind profiles per Generator*

### 1.4.4 Results

We initially study the planning results when considering perfect competition or Cournot oligopoly in the lower level, both for the deterministic and stochastic case. We thus define six different types of problems:

Deterministic Perfect Competition (DT-PC), Deterministic Cournot Oligopoly (DT-CO), Stochastic Perfect Competition (ST-PC) and stochastic Cournot Oligopoly (ST-CO).

*Table XI: Cases Definition*

| DT-PC | DT-CO | ST-PC | ST-CO | RM-PC | RM-CO |
|---|---|---|---|---|---|
| Deterministic optimization with perfect competition in the lower level | Deterministic optimization with Cournot oligopoly in the lower level | Stochastic optimization with perfect competition in the lower level | Stochastic optimization with Cournot oligopoly in the lower level | Minimizing Maximum Regret with perfect competition in the lower level | Minimizing Maximum Regret with Cournot Oligopoly in the lower level |

In Figure 46 we see the total capacity invested in wind and storage technologies for every case. Please note that the Wind capacity is divided by 10 in the graph (scaling purposes). First, only one line is invested for the Perfect Competition (_PC) cases, there is lower investment in wind and therefore higher investment in storage compared to the Cournot Oligopoly (CO) case. This result can be explained because in the CO case no transmission line is built and therefore more generation capacity is needed to supply the demand. Additionally, in general the capacity invested in the stochastic (_SC) cases is lower than in the deterministic (DT). This is clearly seen because the higher variability of wind profiles makes the wind investment less profitable. . It is interesting to note he RM scenario is the most extreme case, where there is PC it is the scenario with the highest investment while in the CO case it is the one with the lowest investment, this suggest that in the CO case the best way minimize the maximum regret is to install the lower wind and storage capacity to limit the market power while in the PC case installing more capacity leads to minimize the regret as the capacity would be optimally utilized.

We now compare the results in terms of the expected social welfare. As seen in Figure 47. The total welfare is higher in the PC cases compared to the CO cases, in part this is given because more demand in supplied in the PC case compared to the CO case. Additionally, the producer surplus is higher in the CO case than in the PC case. Finally, please note that the difference in the total welfare between the deterministic, min-max regret and stochastic case is very small, it accounts to less than the 0.1%, while there is a difference of the 10% between the PC cases compared to the CO case. This might suggest that, for this case study, the imperfect competition has a higher impact on the system planning than the uncertainty of the renewable sources.

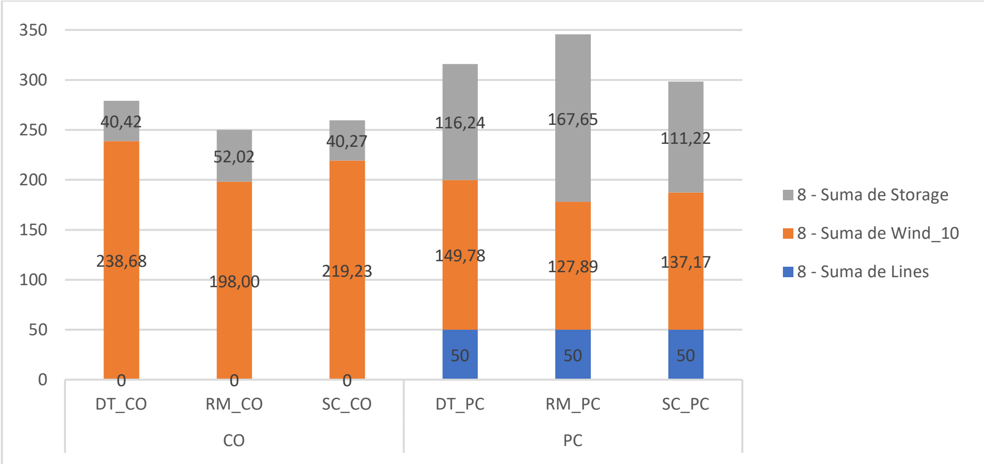


*Figure 24: Capacity Invested*

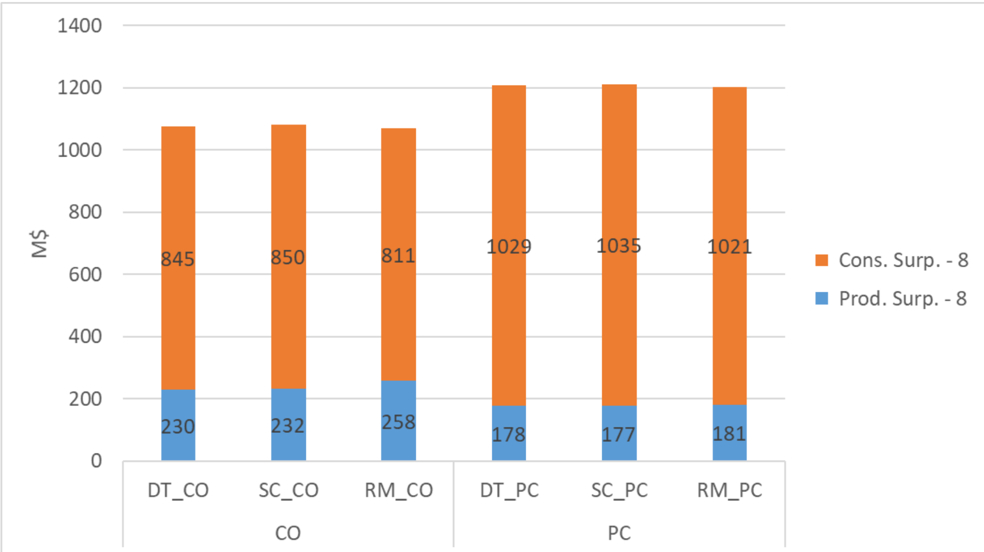


*Figure 25: Total Surplus*

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