The Climate and Economic Rationale for Investment in Life Extension of Spanish Nuclear Plants

Anthony Fratto Oyler[*] and John Parsons[‡]

November 19, 2018

Abstract

Spain's seven operating nuclear plants currently provide more than 20% of its electricity. Each of these began operation in the 1980s and is approaching the end of its 40-year design life. Extending their lives will require additional investments. Should Spain make the investment and extend their lives, or should they be retired at the end of their design life? We show that investing in nuclear plant life extensions is the least-cost alternative for further reducing GHG emissions. We also show that in assessing the cost of renewable alternatives it is critical to take into account the time profile of the available renewable resource. Solar PV and especially wind capacity were expanded significantly since 2000, and significantly greater penetration, especially of solar PV, is promised out to 2030 in order to reduce GHG emissions still further. We show that at these expanded penetration levels, curtailment becomes a significant determinant of system cost. This significantly improves the relative value of nuclear life extensions as a contributor to reducing GHG emissions.

[*]MIT Technology and Policy Program and MIT Center for Energy and Environmental Policy Research (CEEPR).

[†]MIT Sloan School of Management and MIT Center for Energy and Environmental Policy Research (CEEPR).

[‡]This research was supported by a grant from Iberdrola.

1 Introduction

Spain, like many other countries, is faced with important choices about its future energy sector. How can it provide access to low cost energy while also dramatically reducing its greenhouse gas (GHG) emissions? In particular, a key choice is the future mix of electricity generation assets. Currently, more than 20% of Spain's electricity is provided by its seven operating nuclear power reactors. Each of these began operation in the 1980s and is approaching the end of its 40-year design life. Extending their lives will require additional investments. Should Spain make the investment and extend their lives, or should they be retired at the end of their design life?

Spain's nuclear power plants are a very low-carbon source of electricity, alongside Spain's wind, hydro, and solar power capacity. If Spain does not extend their lives, and the plants are retired, then Spain must select a replacement for the lost generation. That could be some mix of additional renewables, including solar PV, wind or hydro. Alternatively, it could include some incremental use of fossil-fueled generation, which would produce incremental GHG emissions. How does the cost of life extensions at the seven nuclear power plants compare against the costs of the replacement options?

We show that investing in nuclear plant life extensions is the least-cost alternative for further reducing GHG emissions. We also show that in assessing the cost of renewable alternatives it is critical to take into account the time profile of the available renewable resource. Solar PV and especially wind capacity were expanded significantly since 2000, and significantly greater penetration, especially of solar PV, is promised out to 2030. We show that at these expanded penetration levels, curtailment becomes a significant determinant of system cost. This significantly improves the relative value of nuclear life extensions.

Of course, other criteria besides cost should also rightly enter Spain's decision, such as safety, the nuclear industry's contribution to Spain's economic development, and land-use priorities but we do not address them here. We do address Spain's responsibility to reduce GHG emissions, both by explicitly recognizing the impact of the generation mix on emissions, and also by incorporating an emissions price or charge as a cost when making comparisons with fossil fuel-fired generation alternatives.

The next section provides background information on Spain's current electricity system, its nuclear power industry, and its energy and climate policy. Section 3 contains our analysis of system costs with and without the nuclear plant life extensions. In Subsection 3.1 we begin by presenting some data to motivate the importance of the time profile of resource availability in the determination of system cost for the Spanish system. We then turn in Subsection 3.2

to select of set of alternative portfolios with and without nuclear plant life extensions. We construct 2 sets of alternative portfolios which achieve the same level of GHG emissions but vary capacity between nuclear and solar PV and wind. This allows us to separate the choice of GHG emission level from the choice of how to achieve a given level. In Subsection 3.3 we detail our cost inputs and discuss how they compare against some benchmarks. Subsection 3.4 translates our inputs into LCOEs based upon assumed capacity factors. This is, of course, not a true system cost calculation, but provides useful benchmarks of our cost inputs and also of the relative cost of the alternatives under this simplified concept. Subsection 3.5 executes the true system cost calculation using a least-cost dispatch algorithm together with a storage optimization routine. Section 4 then concludes with a discussion of a variety of issues.

2 Background

2.1 Spain's Current Electricity System

Table 1 shows peninsular Spain's current electricity capacity and generation mix.[1] The country has nearly 100 MW of capacity spread among a diverse mix of resources, including a large set of nuclear plants, a significant amount of hydro and wind facilities, a smaller set of solar facilities, and a large set of coal plants, natural gas combined-cycle plants and cogeneration plants, and others. In 2017, Spain's electricity demand on the peninsula totaled approximately 253 GWh. More than 20% of demand was supplied by the nuclear plants. Renewables combined provided 33%, while fossil fuel-fired generation supplied 42%. The balance of 4% was supplied from net imports.

Spain's nuclear capacity has been relatively steady since the 1990s. The retirement of a pair of old and small units has been balanced by capacity uprates at the remaining plants. Spain's natural gas combined-cycle plants were built out quickly starting in the mid-1990s. The country has long had significant hydro capacity, which has also increased in recent decades. Its wind capacity has grown dramatically since 2000, and solar PV capacity has grown, too. In contrast, the country's coal-fired capacity fell slightly over the past decades, while oil-fired units almost completely disappeared. The financial crisis of 2007-2008 and the

[1]We restrict our analysis to Spain's peninsular system, i.e., excluding the Balearic and Canary islands as well as the African coastal cities of Ceuta and Melilla. However, the accounting includes the power delivered from the peninsula over the Balearic HVDC link. Also, it only includes power delivered over the transmission network, and so does not include self-consumption from PV or other generation located behind the meter.

Table 1: Spain's Electricity Capacity and Generation Mix in 2017

		Installed Capacity (MW) [A]	Share [B]	Demand & Generation (GWh) [C]	Share [D]	Capacity Factors [F]
	Spanish Generation (Peninsula)					
[1]	Nuclear	7,117	7%	55,609	22%	89%
[2]	Hydro	20,331	20%	18,359	7%	12%
[3]	Wind	22,863	23%	47,497	19%	24%
[4]	Solar photovoltaic	4,431	4%	7,977	3%	21%
[5]	Solar thermoelectric	2,299	2%	5,348	2%	27%
[6]	Other renewables	807	1%	4,330	2%	61%
[7]	Coal	9,536	10%	42,593	17%	51%
[8]	Combined cycle	24,948	25%	33,855	13%	15%
[9]	Cogeneration and other	6,979	7%	30,587	12%	50%
[10]	Total	99,311		246,155		
[11]	Pumped hydro generation			2,249		
[12]	Storage consumption			-3,675		
[13]	Balearic Islands' link			-1,179		
[14]	Net imports			9,171	4%	
[15]	Demand			252,721		

Source: Comisión de Expertos de Transición Energética, 2018, Análisis y propuestas para la descarbonización, p. 120, Gráfico 10 & 11, and for Balearic link, p. 126, Gráfico 16.

Notes:

[2] and [11]: Hydro capacity in [2A] includes pumped hydro, while for generation, pumped hydro is shown separately in [11C]. Hydro capacity factor in [2F] includes pumped hydro generation.

[D]: Generation share is calculated as share of demand, [15C].

ensuing recession put an end to an era of rapid growth in demand. It also created a fiscal crisis for the government and for the funding for the expansion of renewables. Consequently, recent years have seen little increase to overall capacity, and a small reduction in coal-fired capacity. See the International Energy Agency (IEA) (2001) and (2015) and Red Eléctrica de España (REE) (2017).

The Spanish system has long exhibited excess generation capacity–IEA (2001). This continues to be the case today as is evident from the capacity factors for the fossil fuel-fired units displayed in Table 1. The natural gas combined-cycle units have an average capacity factor of 16%. The coal and cogeneration units have capacity factors of approximately 50%. Capacity adequacy in Spain is measured by a coverage index (el índice de cobertura), which is a ratio of aggregate derated capacity over the forecasted maximum hourly demand. Derating accounts for the inherently different capacity factors of different technologies–i.e., solar units only produce for a fraction of the hours each day–and also for the coincidence of availability with peak demand, for uncertainties such as potential outage rates, and for specified contingencies, such as the lack of import capacity. A coverage index of 1.1 is considered the minimum necessary for security. Since 2008, the coverage index has never been less than 1.23 and has reached as high as 1.45–REE (2017).

2.2 Spain's Nuclear Power Industry

Spain's first generation of three nuclear power reactors went into commercial operation between 1969 and 1972. Those plants have all been permanently shutdown. The seven reactors in operation today are a second generation of builds that went into commercial operation between 1983 and 1988. Table 2 lists each reactor, its current capacity, and date of commercial operation.

The seven second generation reactors were to be the first part of a larger, ambitious buildout. However, the election of a new government in 1984 triggered a revision to that plan. The last four of the seven then still under construction were allowed to proceed to completion, while a moritorium on further work was placed on five other units also then under construction. The moratorium had initially left open the possibility that the five units could be completed sometime in the future, but a 1994 act finalized their abandonment and cancelled long postponed plans for future projects. No other new plants have since been planned. However, since 1994, investments in uprates at the existing plants has added nearly 600 MW of nuclear capacity.[2]

[2]See Rubio-Varas, M. D. Mar, and Joseba De la Torre, J. (2017), pp. 140-145, incl. fn. 86, the IEA

Table 2: Spain's Seven Operating Nuclear Power Reactors

	Capacity	Commercial Operation Date	Current Permit Expiry	Age at Expiry	40th Anniversary	50th Anniversary
Almaraz I	1,011	1-Sep-1983	7-Jun-2020	36.8	1-Sep-2023	1-Sep-2033
Almaraz II	1,006	1-Jul-1984	7-Jun-2020	36.0	1-Jul-2024	1-Jul-2034
Asco I	995	10-Dec-1984	1-Oct-2021	36.8	10-Dec-2024	10-Dec-2034
Asco II	997	31-Mar-1986	1-Oct-2021	35.5	31-Mar-2026	31-Mar-2036
Cofrentes	1,064	11-Mar-1985	19-Mar-2021	36.0	11-Mar-2025	11-Mar-2035
Trillo I	1,003	6-Aug-1988	16-Nov-2024	36.3	6-Aug-2028	6-Aug-2038
Vandellos II	1,045	8-Mar-1988	25-Jul-2020	32.4	8-Mar-2028	8-Mar-2038
Total	7,121					

Source for capacity and commercial operation dates: IAEA, PRIS database.

Source for current permit expirty: https://www.csn.es/seguridad-nuclear/autorizacion-de-instalaciones

Almaraz I	Orden ITC/1588/2010, de 7 de junio, por la que se concede renovación de la autorización de explotación de la Central Nuclear Almaraz, Unidades I y II, Minetur, Boletín Oficial del Estado, 16 de junio de 2010, Núm. 146, Sec. III, Pág. 51617-51621.
Almaraz II	Orden ITC/1588/2010, de 7 de junio, por la que se concede renovación de la autorización de explotación de la Central Nuclear Almaraz, Unidades I y II, Minetur, Boletín Oficial del Estado, 16 de junio de 2010, Núm. 146, Sec. III, Pág. 51617-51621.
Asco I	Ordenes Ministeriales por las Que Se Renuevan las Autorizaciones de Explotación de las Centrales Nucleares Ascó I y Ascó II, 23 septiembre de 2011, Minetur.
Asco II	Ordenes Ministeriales por las Que Se Renuevan las Autorizaciones de Explotación de las Centrales Nucleares Ascó I y Ascó II, 23 septiembre de 2011, Minetur.
Cofrentes	Orden por la que se concede la renovación de la autorización de explotación de la Central Nuclear de Cofrentes, 10 de marzo 2011, Minetur.
Trillo I	Orden IET/2101/2014, de 3 de noviembre, por la que se concede la renovación de la autorización de explotación de la central nuclear Trillo I, Minetur, Boletín Oficial del Estado, 11 de noviembre de 2014, Núm. 273, Sec. III, Pág. 92890-92895.
Vandellos II	Orden ITC/2149/2010, de 21 de julio, por la que se concede la renovación de la autorización de explotación de la central nuclear Vandellós II, Minetur, Boletín Oficial del Estado, 5 de agosto de 2010, Núm. 189, Sec. III, Pág. 68419-68423.

The operating performance of Spain's seven operating reactors has been consistently good according to data reported by the IAEA (2018). The average lifetime capacity factors is 85.8%, with the lowest being 82.8%. In comparison, the global average is 73.0%, the U.S. average is 81.6% and the French average is 76.2%. The last 10-year's performance has been above these lifetime averages.[3]

Nuclear operating licenses in Spain are issued by the energy ministry following receipt of a report and certification from the Nuclear Safety Council (CSN, Consejo de Seguridad Nuclear). Licenses are usually for 10-year periods, although they can be for a shorter time. Table 2 shows that the current operating licenses all expire somewhere between 2020 and 2024.

The design life (vida de diseño) of Spain's current reactors is 40 years. Table 2 shows that the age of each reactor at expiry of the current license is less than 40 years, and so the license must be renewed once in order to finish out their full design life. The design life provides a term within which the integrity of the materials and other features are assured under various assumptions about operating conditions and stresses. Integrity can be assured over a longer period, depending upon how the plant has been operated and upon investments made in specific components. In 2004, the CSN established the criteria for evaluating authorizations for long-term operation, i.e., beyond the design life (las Autorizaciones de Explotación a largo plazo)–and in 2009 these were incorporated into Spanish law–Consejo de Seguridad Nuclear (2004) and (2009).

The first reactor to be considered for an operating license that extended past its 40-year design life was the Santa María de Garoña plant in Burgos. In 2009, CSN had approved the plant's operation for another ten years, to 2019, which extended eight years beyond its 2011 design life. However, the ministry then approved a license to 2013 only, two years beyond its design life–Garea (2009). In 2012, a new government considered granting a license for the plant to operate to 2019–Cybulski (2012). However, the plant's owners decided that a new set of taxes and levies made continued operation uneconomical, and they closed the plant in 2013. It has since been permanently shutdown–IAEA (2018).

Table 2 also shows the 40th and 50th anniversary dates of commercial operation. The end of the 40-year design lives are all reached before 2030–in the years from 2023 to 2028–and a 10-year life extension would extend past 2030. Figure 1 shows the overlapping windows of

(2001), p. 63, and IEA (2015), pp. 135-136.

[3]For capacity factor, we use the IAEA's Load Factor (LF), except in quoting data for the U.S. and France where we only have the average for the Energy Availability Factors (EAF). The Spanish reactor's EAF's are all approximately equal to their LF, so the comparison is valid.

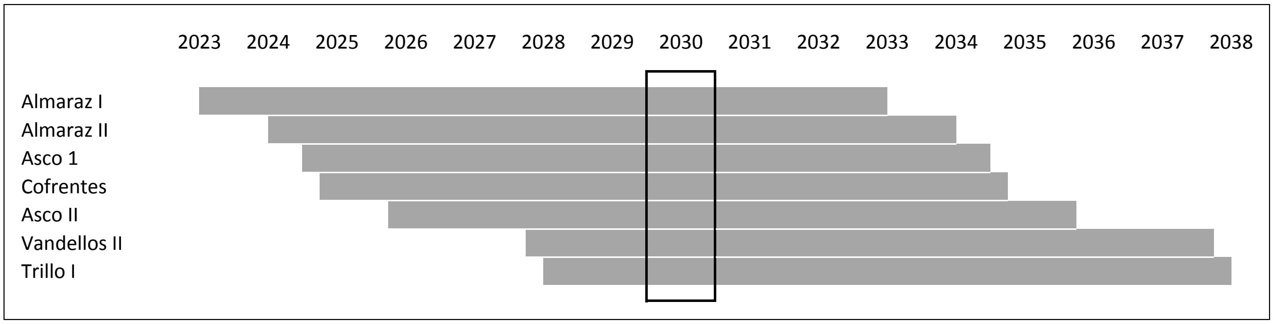

Figure 1: The Overlapping Windows of a 10-year Life Extension for each Reactor and the 2030 Window

operation under 10-year life extensions for each reactor. The year 2030, which is highlighted in the figure, is in the center of the combined window of operation under life extensions. Therefore, our later calculations focus on forecasted system operation in the year 2030.

2.3 Spain's Energy and Climate Policy

The countries of the European Union (EU) have committed to reduce GHG emissions in the EU 20% by 2020, 40% by 2030, 60% by 2040 and 80% by 2050, as compared to 1990 levels–European Commission (2018a). The targeted reductions in the sectors covered by the EU's Emissions Trading Scheme (ETS), including the electricity sector, are greater still. They call for a reduction of 21% by 2020 and 43% by 2030, as compared to 2005 levels–Comisión de Expertos de Transición Energética (Commission of Experts) (2018), pp. 46-47 and 134. However, the targeted reduction in the ETS sector are EU-wide commitments, and individual country emissions may decline by more or less depending upon cross-country trading within the EU-wide cap.

Table 3 shows Spain's economy-wide emissions trajectory from 1990 to 2005 and to 2015. It also shows the emissions from Spain's electricity sector–both national and peninsular. The final column provides a benchmark for 2030 emissions based on the EU targets. The benchmark for total emissions assumes that the EU-wide target devolves to a comparable reduction in Spain, and the benchmark for electricity sector emissions further assumes that the ETS-wide reduction occurs equally in both the electricity and the non-electricity components of the ETS-covered sectors. Neither assumption need hold, which is why these are simply useful benchmarks and not strict requirements. As rows [2] and [3] show, electricity sector emissions have already declined significantly. However, a further decline is needed to achieve the 2030 target. This will need to be done in the face of a projected increase in

Table 3: Greenhouse Gas Emissions and Targets, Total and for the Electricity Sector (MT CO_2eq)

		Spanish Emissions 1990 [A]	2005 [B]	2015 [C]	EU-wide Target 2030 [D]	Spanish Benchmark 2030 [E]
[1]	Total emissions	287.8	439.6	335.7	-40% from 1990	172.7
	Electricity Sector					
[2]	National		107.6	77.8	-43% from 2005	61.4
[3]	Peninsular		102.5	67.8		58.4

Sources:

[1A]-[1C]: Ministerio de Agricultura y Pesca, Alimentación y Medio Ambiente (Mapama), 2017, España: Inventario Nacional De Emisiones De Gases De Efecto Invernadero, 1990 – 2015, Comunicación Al Secretariado De La Convención Marco De Nnuu Sobre Cambio Climático.

descarbonización, p. 134. For [3B], see also Red Eléctrica de España (REE), "Spanish Electricity System 2017 Preliminary Report".

[2C] and [3C]: Red Eléctrica de España (REE), Emisiones de CO2 asociadas a la generación anual, "RedElectrica_4_Emisiones_CO2_04_2018.xlsm".

[1E]-[3E]: Calculated as shown. For [3E] the Comisión de Expertos reports a smaller value of 53.5.

electricity demand.

The countries of the EU have additionally committed to achieving an ambitious target for the use of renewables: 20% of final energy use by 2020, and 32% by 2030.[4] Under all scenarios for achieving these goals, the penetration in the electricity sector is greater than the economy-wide target. Table 1 shows that renewables currently account for 33% of generation.

Spain has also been debating the fate of its fleet of coal-fired plants. The need to reduce GHG emissions and increase the penetration of renewables argues for a reduction in coal use. Closure of certain units before 2030 is also necessary to meet EU directives on air quality. However, many of the coal plants are important to the economic life of their respective regions. How to make the transition is an important, unresolved political task.

Spain has also agreed to a variety of other policies designed to contribute to reducing GHG emissions, including improved energy efficiency and improved grid interconnections among many others.

There are many possible ways to meet these various targets for the electricity sector.

[4]The original commitment was 27% by 2030. The more aggressive 32% commitment was recently arrived at through negotiations among the European Commission, Parliament and Council, although it has yet to be formally passed as legislation. See the European Commission (2018b)

Table 4: A Possible Scenario for Capacity and Generation Mix in 2030 from the Commission of Experts' Report

		2030 Base Case					Change from 2017 Actual			
		Installed Capacity		Demand & Generation		Capacity Factors	Installed Capacity		Demand & Generation	
		(MW)	Share	(GWh)	Share		(MW)	% Δ	(GWh)	% Δ
		[A]	[B]	[C]	[D]	[F]	[G]	[H]	[I]	[J]
	Spanish Generation (Peninsula)									
[1]	Nuclear	7,117	5%	50,868	17%	82%	0	0%	-4,741	-9%
[2]	Hydro	23,050	15%	32,257	11%	21%	2,719	13%	13,898	76%
[3]	Wind	31,000	21%	64,923	22%	24%	8,137	36%	17,426	37%
[4]	Solar photovoltaic	47,157	32%	88,027	30%	21%	42,726	964%	80,050	1004%
[5]	Solar thermoelectric	2,300	2%	4,589	2%	23%	1	0%	-759	-14%
[6]	Other renewables	2,550	2%	13,409	5%	60%	1,743	216%	9,079	210%
[7]	Coal	847	1%	0	0%	0%	-8,689	-91%	-42,593	-100%
[8]	Combined cycle	24,560	16%	34,702	12%	16%	-388	-2%	847	3%
[9]	Cogeneration and other	8,500	6%	38,675	13%	52%	1,521	22%	8,088	26%
[10]	Batteries	2,358	2%			26%	2,358			
[11]	Total	149,439		327,449			50,128		81,294	33%
[12]	Pumped hydro generation			10,838					8,589	382%
[13]	Battery generation			5,319					5,319	
[14]	Storage consumption			-20,319					-16,644	453%
[15]	Balearic Islands' link			-1,982					-803	68%
[16]	Net exports			-27,332	-9%				-36,503	-398%
[17]	Demand			295,955					43,234	17%

Source: Comisión de Expertos de Transición Energética, 2018, Análisis y propuestas para la descarbonización, pp. 112-113, Gráfico 7 & 8, and p. 249 and p. 255, Anexo 1B.

Notes:

[2] and [12]: Hydro capacity in [2A] includes pumped hydro, while for generation, pumped hydro is shown separately in [12C]. Hydro capacity factor in [2F] includes pumped hydro generation.

[10] and [13]: Consistent with the presentation of pumped hydro, battery capacity is in [10A] while generation is in [13C]. Battery capacity factor in [13F] uses generation in [13C].

[17C]=[11C]+[12C]+[13C]+[14C]+[16C]. Properly done, the deliveries to the Balearic islands, [15C] should also be included in the sum. However, in the Comisión de Expertos report, Demand is shown as 296 TWh as shown here. The presentation in that report suggests this ignores deliveries from the Peninsula to the Balearic islands.

However, it will be helpful to the discussion if we focus on one that is broadly familiar to participants in Spain's conversation on energy and climate policy. Table 4 shows one such scenario for Spain's mix of capacity and generation in 2030. This scenario–DG2030–is an element of the *Ten-Year Network Development Plans 2018* (TYNDP) developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) (2017) in collaboration with their sister organization responsible for natural gas transmission systems. It was used as one Base Case scenario in the report by Spain's Commission of Experts (2018). The Commission had been tasked in 2017 with informing Spain's Interministerial Working Group's development of a future Law on Climate Change and the Energy Transition. The Commission included participants from each of the parliamentary groups, among others, and its report included a wide array of alternative scenarios besides the one displayed in Table 4. Since the release of the Commission's report, Spain has already experienced a change of government, which only emphasizes the need to be open to alternative scenarios. Our objective is precisely to explore one dimension of the choice set, which is the role that nuclear may play within a larger strategy. We believe that the scenario sketched by the Commission and shown in Table 4 is a useful reference point for that analysis. We will examine alternative mixes of capacity around this reference point. Some will retain the existing nuclear plants, while others will not.

In Table 4, the last four columns, [G]-[J], show the change in capacity and generation relative to 2017–i.e., the difference from the numbers shown in Table 1. From the bottom row, one can see that between 2017 and 2030 demand grows by 17%, which is a 1.2% annual growth rate. Capacity is added to supply that demand, but the mix of capacity is also dramatically altered in order to meet the climate targets. The changes can be summarized as follows:

- an additional 42 GW of solar PV capacity, which is an enormous 9 times the total capacity installed to date requiring an annual expansion rate of nearly 20%;
- an additional 8 GW of wind capacity, which is 36% more than the current capacity, implying an annual growth rate of more than 2.4%;
- an additional 2.7 GW of hydro capacity, which is which is 13% more than the current capacity, implying an annual growth rate of nearly 1%; most of the expansion is in pumped hydro capacity, where the increase amounts to a 38% expansion, or an annual rate of approximately 2.5%;
- an initial 2.4 GW of battery capacity;
- the virtually complete shutdown of coal plants;
- a small decrease in combined-cycle capacity, reflecting the already announced closure of one plant;
- a modest expansion in cogeneration and other capacity;
- the continued operation of the nuclear capacity;

The profile of this altered capacity mix is mirrored in the profile of the altered generation mix.

- Solar PV and wind generation expand roughly in line with their expanded capacity, although at this level of penetration, there is a modest 2.7% curtailment (curtailment data not shown in the table, see Commission of Experts (2018), Tabla 8, p. 133;
- Hydro generation expands, but this reflects in part the fact that 2017 was a very dry year and the assumed hydro conditions behind Table 4 are for a more average volume of resource, so only some of this expansion is due to new investments;
- the use of storage, both from pumped hydro and batteries, expands 6 times, while consumption from storage expands 3.5 times;
- a small reduction in nuclear generation in response to the expanded use of renewables;
- a dramatic shift from being a net importer of power, to being a significant net exporter, which helps to minimize the curtailment of renewables.

Renewable generation here accounts for 69% of demand, while fossil generation has declined to 25%. GHG emissions from the electricity sector are estimated to be 12.59 MTCO2eq, which is far below the 2030 benchmark.[5]

It must be emphasized that this is an extremely ambitious scenario. The scale of growth of certain technologies would be extremely challenging, both because of the pace and because of the natural resource and social capacity limits against which they press. Of course, the urgent challenge of reducing GHG emissions demands significant change, so an ambitious scenario may be fit-to-purpose. Nevertheless, it is important to appreciate the full meaning of the numbers on the page.

The capacities shown in Table 4 were chosen to serve the demand shown in the table. However, they are not sufficient to provide security of supply. The coverage ratio for that system equals 1.0, which is below the required hurdle 1.1. That is, an additional 4.722 GW of derated capacity is required to reach the hurdle of 1.1–see Commission of Experts (2018), Tabla 12, p. 137. Therefore, although the table shows the capacity of combined-cycle units declining, in point of fact, the coverage ratio will require an investment in more than 2.6 GW of combined-cycle units or a suitable alternative. However, note that in the scenario, generation from combined-cycle units declines from 2017. So, there is a need to expand combined-cycle capacity while also decreasing generation. The realized capacity factor will therefore fall markedly. We will return to this point in our later analysis.

[5]Emissions from cogeneration are not included in this value since they are attributed to the industrial sector.

3 System Cost

In evaluating cost efficiency, we look at the total system cost. That is, we examine the full portfolio of capacity required to serve demand in all hours and calculate the investment needed to install the capacity plus the cost of operating the capacity. We ask whether nuclear life extensions produce the lowest system cost, or whether investments in alternatives–such as solar PV, wind or natural gas combined-cycle capacity–produces a lower system cost.

The challenge of identifying the least-cost portfolio of technologies is known as the capacity investment problem. A classic example involves selecting a portfolio of alternative dispatchable thermal technologies differentiated by the ratio of fixed and variable cost. A classic solution is provided by the screening curve methodology which determines the capacity factors at which successive pairs of technologies with increasing fixed cost have the same marginal total cost and then invests in each technology to serve that segment of demand for which it has the lower marginal cost. However, realistic problems are much more complex. For example, the screening curve methodology disregards the chronologic sequence of demand, and therefore ignores the issues of minimum generation levels and ramp rates. It also disregards uncertainty about the level of demand and how this impacts the optimal portfolio of investments. Of course, these other issues can be tackled with the help of more detailed capacity planning models which have been elaborated over many decades. For a recent review of modeling advances, see Jenkins (2018). The bottom line, however, is that a complete optimization of capacity investments is a very complex problem, and in most policy discussions such as this one, it will be necessary to identify a few important dimensions and focus on those.

With the rapid penetration of renewable generation in recent years, it has become important to analyze how the time profile of renewable resources correlate with the time profile of demand. Investments in renewable capacity add significant generation in some hours, and less in others. At a very large scale of renewable capacity, it may be necessary to curtail renewable generation in certain hours in which case the cost of a marginal unit of the renewable generation is increasing in the penetration. Even without curtailment, the mismatch between the time profile of the renewable resources and load will make system cost vary with renewable penetration since the system cost accounts for the investment needed to fill the gaps which may require dispatchable technologies operated at lower and lower capacity factors. There is a significant literature highlighting this issue, including Joskow (2011), NEA (2012a), Hirth (2013), Schmalensee (2013), NEA (2018), and Bushnell and Novan (2018), among many others. Sepulveda et al. (2018) is an example of a full scale capacity investment model which takes into account the calendar profile of resource availability across the many hours of the year and selects a combination of renewable and non-renewable technologies with the lowest cost. Ueckerdt et al. (2013) translate the results of an integrated model to calculate a 'System LCOE' and show that at significant level of renewable penetration, the increment to cost is significant. Hirth (2015) uses a model incorporating resource availability constraints to estimate an optimal deployment of wind generation in Germany of 20%.

3.1 The Importance of Renewable Resource Availability for the Spanish System Cost in 2030

Already in 2017, the Spanish system included significant renewable capacity. At the expanded scale of renewable capacity projected for 2030, the effect of resource availability is likely to be an important factor to consider. We illustrate this with a 2030 scenario for hourly load and hourly resource factors.[6] For load, we use the hourly values in ENTSO-E's (2017) DG2030 scenario.[7] For hydro, we use REE's hydro index flow factor through the calendar year given the median aggregate annual resource–REE (2018a). These are the load and hydro scenario adopted by Spain's Commission of Experts report for the Base Case scenario shown in Table 4. For wind and solar, we construct a scenario of hourly resource factors matching the average calendar pattern and hourly volatilities reflected in the actual generation for 2014-2017 as reported in the P48 file of REE's (2018b) eSios database and using the capacities reported in REE's (2018d) Statistical series of the Spanish electricity system.

Figure 2 shows the correlation between the hourly wind resource factors and load in this 2030 scenario. The hourly resource factor varies from just below 1% up to 75%, while the hourly load varies between 21-48 GW. Note that for any level of resource factor, there are many hours with loads varying across most of the full range of the load, 21-48 GW.

This graph helps us to visualize a key constraint forcing wind capacity factors to decline as installed capacity grows. Overlayed on the data are three lines that show the potential hourly generation that would be produced at three different levels of installed wind capacity. The lowest line shows the potential hourly generation with installed capacity of 20 GW, which

[6] A resource factor is a number between 0 and 100% that measures the potential amount of generation in an hour produced by 1 unit of available capacity, assuming no curtailment. If there is no curtailment, then the resource factor is the same as the capacity factor. Curtailment reduces the realized capacity factor, but not the resource factor. Thus, a resource factor is comparable to a thermal unit's availability factor.

[7] The hourly series is reported in an ENTSO-E spreadsheet labeled "Load_Series_2030_DG.xlsx". It is the series reflecting the climatic variation for 1984.

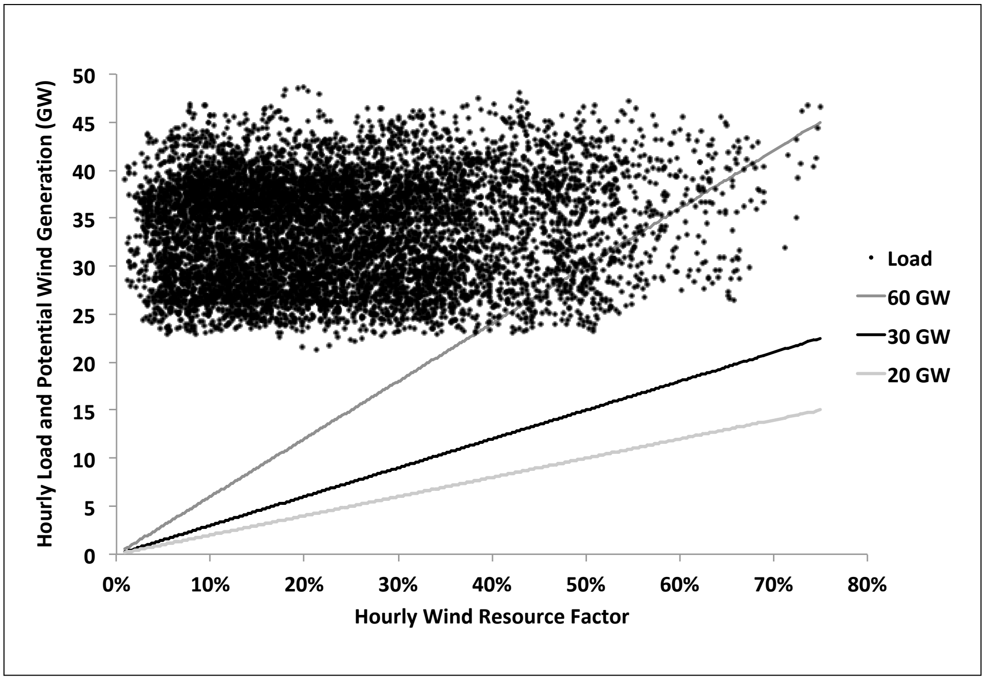

Figure 2: The Correspondence Between the Hourly Wind Resource Factor and the Hourly Load, 2030 Forecast Scenario.

is approximately the capacity in 2017. Note that the potential generation in every hour is far below the load in any hour. The middle line shows the potential hourly generation with installed capacity of 30 GW, which is approximately the capacity in the base case scenario for 2030 shown in Table 4. Once again, note that the potential wind generation in every hour is still below the load in any hour, although depending upon the other renewable resources it is clear that curtailment in certain hours may be likely. The highest line shows the potential hourly generation with installed capacity of 60 GW, which is on the order of magniture that would be required if wind capacity were expanded to replace the full nuclear fleet. In this case, there are many hours where the load falls below the line, indicating that the potential wind generation alone is greater than the load. At penetration of 60 GW of wind capacity–and absent storage, which we discuss below–it would be necessary to curtail the wind generation during these hours, even without factoring in generation from hydro, solar PV or other renewables.

Note that the lines in Figure 2 are all anchored on the left-hand-side at zero. As additional capacity is installed, large amounts of potential generation are added in the hours to the right, where the resource factor is high, and very small amounts of potential generation are added in the hours to the left, where the resource factor is low. As more capacity is installed

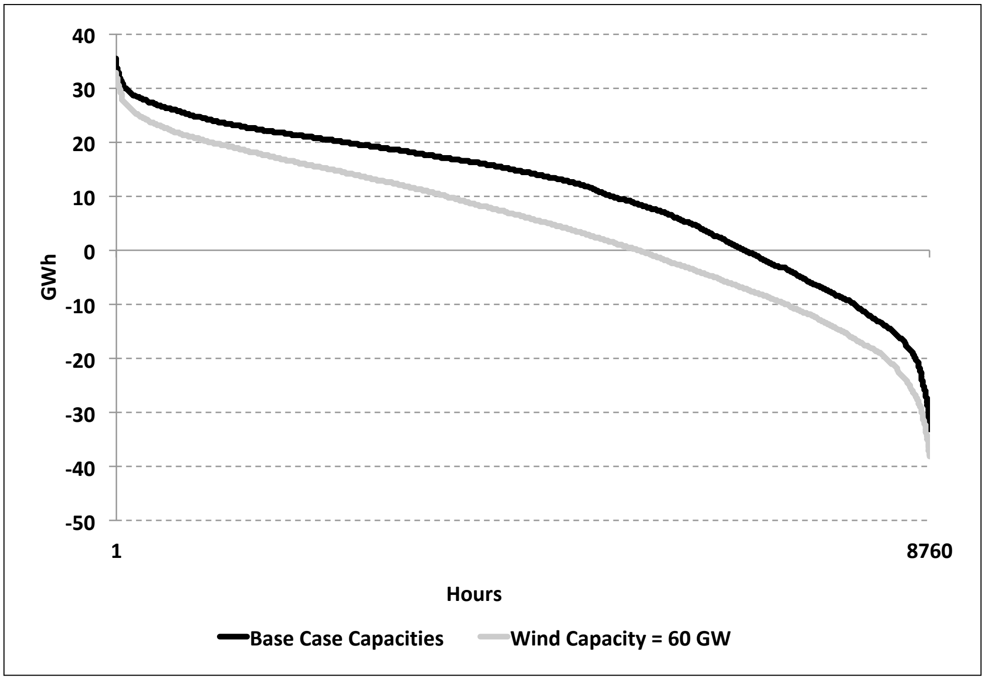

Figure 3: Net Load Duration Curves, 2030 Forecast Scenario and Base Case Capacity.

and the line pivots up, increasing volumes of the potential generation must be curtailed or an increasing volume of storage is required. If wind generation were relied upon to supply load in the hours to the left, it would require very high amounts of generation or storage capacity to deliver a declining volume of generation. Therefore, the cost of serving these units of load using wind generation is more expensive than the cost of serving units of load located on the right in the figure.

Figure 3 brings the aggregate renewable capacity into the picture. The top line shows a net load duration curve for the 2030 hourly scenario: net load in each hour equals load minus the aggregate potential renewable generation given the capacities shown in Table 4. This includes generation from hydro, solar PV, wind, solar thermal and other renewables. The time profile of the hydro resource is taken as given here, before optimization for storage. Total load is 295 TWh, the available renewable generation equals in total more than 201 TWh or nearly 70% of load. The maximum net load is slightly above 35 GW. The curve goes negative at hour 6,777. That is, in 1,984 hours or nearly 23% of the hours in the year, there is more available generation from renewable facilities than there is load. The excess generation in these hours equals more than 9% of the total available generation from renewables.

The second, bottom line shows the net load duration curve calculated assuming installation of additional wind capacity bringing total capacity to 60 GW. The incremental capacity

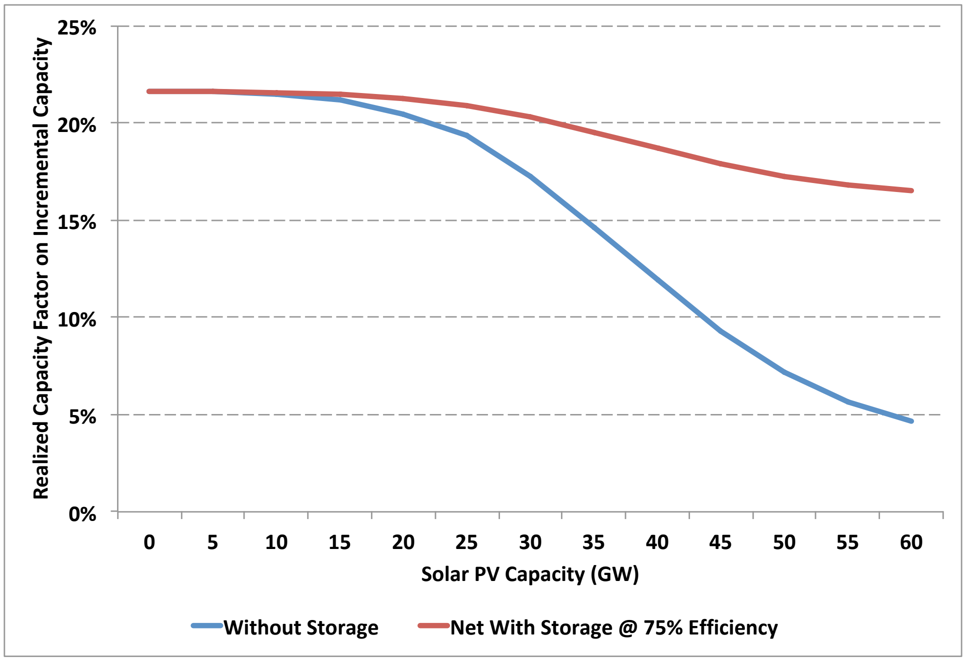

Figure 4: The Declining Capacity Factor for Incremental Solar Capacity, 2030 Forecast Scenario.

is roughly enough to replace generation from the nuclear fleet. The fraction of hours when available renewable generation exceeds load now climbs from 23 to 35%. The excess generation in these hours equals 13% of the total available generation from renewables. Of the incremental generation from the incremental wind capacity, fully 29% will be curtailed unless there is unused storage capacity available to move it to other hours. This curtailment dramatically reduces the effective capacity factor and raises the system cost of reliance on wind capacity.

Table 5 and Figure 4 make a similar point for expansion of solar PV capacity. They show how the realized capacity factor on incremental capacity declines with the level of penetration. The table takes as its starting point the installed capacity for all other types of renewable generation in 2030 as shown in Table 4. Each column shows a different amount of aggregate solar PV capacity starting from 0 GW on up to 60 GW. Row [1] shows the available PV generation, assuming a constant capacity factor of 21.6% across all columns. Row [2] shows the total available renewable generation. Rows [3] and [4] show the number and share of hours in the year this exceeds load. Rows [5] and [6] show the total GWh over load, and that value as a share of the available renewable generation. Rows [7]-[10] show the impact of curtailment assuming no storage. Row [7] is the net renewable generation after

Table 5: The Declining Capacity Factor for Incremental Solar Capacity, 2030 Forecast Scenario.

			Solar PV Capacity (GW)												
			0	5	10	15	20	25	30	35	40	45	50	55	60
[1]	Available PV Generation	(GWh)	0	9,459	18,918	28,376	37,835	47,294	56,753	66,211	75,670	85,129	94,588	104,047	113,505
[2]	Available RES Generation	(GWh)	116,448	125,907	135,366	144,825	154,283	163,742	173,201	182,660	192,119	201,577	211,036	220,495	229,954
[3]	Hours Greater Than Load		0	4	24	93	205	407	740	1112	1485	1854	2153	2366	2549
[4]	Share Hours		0%	0%	0%	1%	2%	5%	8%	13%	17%	21%	25%	27%	29%
[5]	Excess RES Generation	(GWh)	0	1	42	239	731	1,722	3,630	6,672	10,907	16,291	22,599	29,572	36,989
[6]	Share Avail. RES Generation		0%	0%	0%	0%	0%	1%	2%	4%	6%	8%	11%	13%	16%
	Without Storage														
[7]	Net RES Generation	(GWh)	116,448	125,906	135,324	144,586	153,552	162,021	169,571	175,988	181,211	185,286	188,438	190,923	192,965
[8]	Incremental PV Generation	(GWh)	0	9,458	9,418	9,261	8,966	8,469	7,551	6,417	5,223	4,075	3,152	2,486	2,042
[9]	Avg. PV Capacity Factor		21.6%	21.6%	21.6%	21.5%	21.5%	21.4%	21.2%	20.9%	20.7%	20.4%	20.0%	19.8%	19.5%
[10]	Incremental PV Capacity Factor		21.6%	21.6%	21.5%	21.1%	20.5%	19.3%	17.2%	14.7%	11.9%	9.3%	7.2%	5.7%	4.7%
	With Storage @ 75% Efficiency														
[11]	Net RES Generation	(GWh)	116,448	125,907	135,353	144,753	154,064	163,226	172,112	180,658	188,846	196,690	204,257	211,623	218,857
[12]	Incremental PV Generation	(GWh)	0	9,459	18,905	28,305	37,616	46,777	55,664	64,210	72,398	80,242	87,808	95,175	102,409
[13]	Avg. PV Capacity Factor		21.6%	21.6%	21.6%	21.5%	21.5%	21.4%	21.2%	20.9%	20.7%	20.4%	20.0%	19.8%	19.5%
[14]	Incremental PV Net Capacity Factor		21.6%	21.6%	21.6%	21.5%	21.3%	20.9%	20.3%	19.5%	18.7%	17.9%	17.3%	16.8%	16.5%

curtailment. Row [8] shows the incremental generation from the PV–that is, how much net renewable generation increases with the added PV capacity as we move from the left to the right. Row [9] shows the average realized capacity factor for PV, if all of the curtailment was of the PV. Row [10] shows the incremental PV capacity factor–that is, the ratio of the incremental renewable generation in row [8] over the incremental potential PV generation. Row [10] makes no assumption about which renewables are curtailed, since the point is how much additional PV capacity adds to total renewable generation. Row [10] is graphed as the blue line in Figure 4. The scenarios in the columns of Table 5 and the axis of Figure 4 span the 2017 PV capacity, which is slightly less than 5 GW, and the base case 2030 PV capacity, which lies between 45 and 50 GW. Note that at the base case 2030 PV capacity, the incremental PV capacity factor has fallen from 21.6% down to the neighborhood of 8%. Once again, the calculations in rows [7]-[10] do not include the possibility of storage, to which we now turn.

Storage can help move some of this available renewable generation out of the hours where curtailment would be necessary, and into other hours where load exceeds the available renewable generation. An example of an analysis of the role of storage and renewable penetration is Tuohy and O'Malley's (2011) study of pumped storage and wind in Ireland. Lamont (2012) analyzes the impact of storage on enabling investments in both base load and renewables. For the Spanish system in 2030, there are 4 main sources of storage, (i) pumped hydro, (ii) hydro reservoirs, (iii) batteries, and (iv) integrated storage at solar thermal facilities.

The battery installations envisioned in ENTSO-E's (2017) DG2030 scenario is intended to smooth the solar PV generation, capping the peak and adding generation in later hours, much as solar thermal's integrated storage does. However, as Figure 5 illustrates, the scale of the battery installation is relatively small compared to the total solar PV capacity envisioned in the scenario. Therefore, the batteries can be used to full capacity and still only make a modest shift in the daily profile of generation.

The largest source of storage on the Spanish system is through the management of hydro flow using reservoirs and pumped storage. It is difficult to fully characterize the flexibility this affords because it operates under a complex set of constraints and because it is determined by a complex dynamic stochastic optimization problem. However, in the case of pumped storage, the efficiency losses provide us a way to bound the increased flexibility afforded and determine a minimum deterioration in the net capacity factor (solar+battery). Looking back at Table 5, rows [11]-[14] show how the use of storage to alleviate curtailment moderates the declining capacity factor, but does not eliminate it. Every hour of solar generation that must

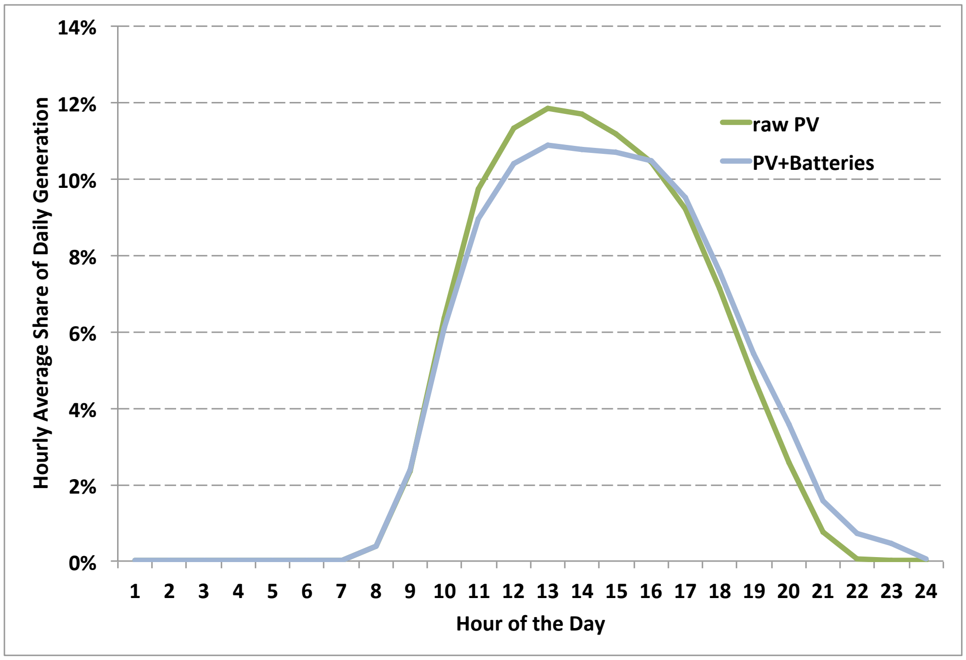

Figure 5: The Average Hourly Generation Profile of Solar PV, Gross and Net of Battery Use, 2030 Forecast Scenario.

be moved to another hour involves an efficiency loss, and this loss reduces the net addition to generation produced by incremental investment in solar PV capacity. The calculations in the table assume any generation in excess of load is stored and used in another hour when renewable generation is less than load, at a constant efficiency of 75%. This bounds the drop in the net capacity factor at 16.2%. The red line in Figure 4 shows how the net capacity factor for incremental capacity additions falls but asymptotes to 16.2%.

The analysis above highlights that the issue of resource factors is likely to play a significant role in determining system cost in Spain, and so we focus our calculation on it.

3.2 Alternative Portfolios

Our analysis addresses the system cost to serve our scenario for hourly load in 2030 given our scenario for hourly resource factors. We consider alternative portfolios of nuclear, solar PV, wind and natural gas combined-cycle capacities, holding constant the capacity of the other technologies, including hydro, solar thermal and other renewables, cogeneration, as well as pumped storage and batteries. Indeed, we hold constant the generation from solar thermal and other renewables, as well as from cogeneration. We optimize generation from hydro reservoirs, pumped hydro and batteries in order to minimize curtailment of solar PV

Table 6: A 2030 Baseline Portfolio of Capacities and the Resulting Generation

		Installed Capacity (MW) [A]	Share [B]	Demand & Generation (GWh) [C]	Share [D]	Capacity Factors [F]
	Spanish Generation (Peninsula)					
[1]	Nuclear	0	0%	0	0%	
[2]	Hydro	23,050	16%	31,645	11%	16%
[3]	Wind	31,000	22%	64,276	22%	24%
[4]	Solar photovoltaic	47,157	33%	87,282	30%	21%
[5]	Solar thermoelectric	2,304	2%	4,022	1%	20%
[6]	Other renewables	2,550	2%	11,871	4%	53%
[7]	Coal	878	1%	0	0%	0%
[8]	Combined cycle	24,560	17%	91,226	31%	42%
[9]	Cogeneration and other	8,500	6%	38,900	13%	52%
[10]	Batteries	2,358	2%			0%
[11]	Total	142,356		329,222		
[12]	Pumped hydro generation			10,772		
[13]	Battery generation			3,920		
[14]	Storage consumption			-19,701		
[15]	Balearic Islands' link			-1,377		
[16]	Net exports			-27,819	-9%	
[17]	Demand			295,017		
	Ancillary Calculations					
[18]	Storage losses			5,009		
[19]	Subtotal, N+W+S-losses			146,549		
[20]	Total, N+W+S+CC-losses			237,775		
[21]	GHG Emissions (MtCO2eq)			33.46		

and wind, as does the timing of generation from non-pumped hydro generation. Among our four candidate technologies, only the natural gas combined-cycle option produces GHG emissions. Moreover, anticipating information on variable operating costs coming in a later section, adding capacity for any of the three other technologies reduces total generation from the combined-cycle units and therefore GHG emissions.

We start with a Baseline portfolio of capacities that has no nuclear plant life extensions and the highest level of combined-cycle generation and therefore the highest level of emissions. This portfolio of capacities is shown in Table 6. This is very close to the portfolio of capacities shown in Table 4, except that the nuclear capacity has been zeroed out. These capacities are sufficient to serve our load scenario, although they do not provide a satisfactory coverage index.

Table 7: A Set of Alternative Capacity Portfolios Benchmarked to 1 Nuclear Plant Life Extension

		[A] N1	[B] S1	[C] W1	[D] SW1	[E] WS1
	Installed Capacity (MW)					
[1]	Nuclear	1,003	0	0	0	0
[2]	Solar	47,157	52,932	47,157	51,119	48,283
[3]	Wind	31,000	31,000	35,550	32,321	34,377
	Generation, Potential (GWh)					
[3]	Nuclear	8,259	0	0	0	0
[4]	Solar	89,210	100,134	89,210	96,720	91,343
[5]	Wind	64,934	64,934	74,465	67,708	72,023

Notes:
[1]-[3] are chosen.
[4]-[6] = Capacity multiplied times exogenously specified availability or resource factor, independent of dispatch.
For nuclear, this availability factor is 94.0%. Therefore, [4] = [1]*94.0%*8.760.
For solar PV, this resource factor is 21.6%. Therefore, [6] = [3]*21.6%*8.760.
For wind, this resource factor is 23.9%. Therefore, [5] = [2]*23.9%*8.760.

We then consider two sets of alternative portfolios with increased capacity from either nuclear, or solar PV, or wind or selected combinations of solar PV and wind, and therefore lower emissions. Within each set, we hold constant the aggregate generation from nuclear, solar PV and wind, and therefore hold constant the generation from the combined-cycle units and emissions. The first set of alternatives is calibrated to a life extension at 1 nuclear plant. Alternatively, we consider additional solar PV capacity instead of the life extension, as well as additional wind capacity instead or combinations of solar PV and wind instead. Table 7 shows the nuclear, solar PV and wind capacities for our first set of 5 alternative portfolios. The portfolio N1 shown in column [A] includes 1 nuclear life extension. The portfolio S1 shown in column [B] includes additional solar PV capacity instead. The portfolio W1 shown in column [C] includes additional wind capacity instead. The portfolios SW1 and WS1 shown in columns [D] and [E] include additional solar PV and wind capacity in two different mixes, 75%-25% solar PV-wind PV and 25%-75%, respectively.

Table 8: A Set of Alternative Capacity Portfolios Benchmarked to 7 Nuclear Plant Life Extensions

		[A] N7	[B] S7	[C] W7	[D] SW7	[E] WS7
	Installed Capacity (MW)					
[1]	Nuclear	7,117	0	0	0	0
[2]	Solar	47,157	156,957	47,157	84,006	55,262
[3]	Wind	31,000	31,000	61,160	43,285	55,306
	Generation, Potential (GWh)					
[3]	Nuclear	58,604	0	0	0	0
[4]	Solar	89,210	296,924	89,210	158,919	104,542
[5]	Wind	64,934	64,934	128,109	90,667	115,847

Notes:

[1]-[3] are chosen.

[4]-[6] = Capacity multiplied times exogenously specified availability or resource factor, independent of dispatch.

For nuclear, this availability factor is 94.0%. Therefore, [4] = [1]*94.0%*8.760.

For solar PV, this resource factor is 21.6%. Therefore, [6] = [3]*21.6%*8.760.

For wind, this resource factor is 23.9%. Therefore, [5] = [2]*23.9%*8.760.

Table 8 shows our second set of 5 alternative portfolios. The portfolio N7 shown in column [A] includes 7 nuclear life extension. This is also approximately the portfolio shown in Table 4. The other portfolios, shown in columns [B]-[E] includes additional wind and solar PV capacity instead, again ranging from pure wind or solar PV to different mixes of both.

Figure 6 is a visual guide to the alternative portfolios. The origin of the figure is the Baseline portfolio with zero nuclear capacity. Along the horizontal axis marked 'N' are alternative portfolios with an increasing number of nuclear plant life extensions. The two points marked on this axis reflect the life extension of 1 single plant and of all 7 plants, respectively. The second point on this axis is therefore approximately the portfolio shown in Table 4. We also consider portfolios along the vertical axis marked 'S', which reflect additional investments in solar PV capacity instead of the nuclear life extensions. And we consider portfolios along the third axis marked 'W', which reflects additional investments in wind capacity instead of the nuclear life extensions. Finally, not shown on the figure, we also consider portfolios with additional investments in different mixes of solar PV and wind

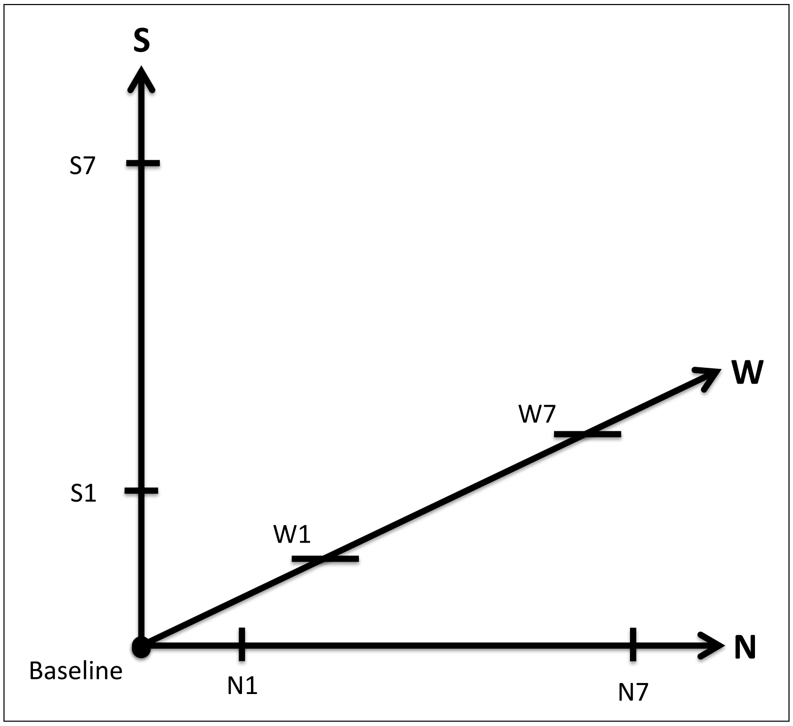

Figure 6: A Visual Guide to the Alternative Portfolios of Capacity.

capacity instead of the nuclear life extensions.

Moving outward from the origin in any direction adds to total low-carbon capacity, resulting in less generation from combined-cycle plants and therefore fewer emissions. Therefore, it is possible to identify portfolios along different rays from the origin which have identical levels of emissions. For example, the portfolio S1 along the vertical axis yields the same amount of carbon emissions as portfolio N1 along the horizontal axis. So does portfolio W1 along the third axis. Similarly, the portfolio S7 along the vertical axis yields the same amount of carbon emissions as portfolio N7 along the horizontal axis. So does portfolio W7 along the third axis. This is the principle behind our construction of two sets of portfolios.

In order to calibrate the necessary amounts of different types of capacity in each set of alternative portfolios, we used a least-cost hourly dispatch model complemented with an algorithm to optimize storage. Anticipating later information on variable operating cost, solar PV and wind generation have priority over nuclear, and nuclear generation has priority over combined-cycle.[8] We simplify the analysis by fixing the hourly generation from solar ther-

[8]The model distinguishes among units within each class where we have information about individual thermal efficiencies or other distinctions. However, given the granularity of our information, this makes only a minor difference to the results.

mal, other renewables and, cogeneration, which combined equal about 20% of demand.[9,10] We also fix net exports from peninsular Spain, whether to the Balearic islands or to France and Portugal. Our analysis abstracts from minimum load and ramping constraints across hours.

The operation of storage is as follows. Batteries are used to extend the time profile of solar PV generation in a manner similar to the operation of storage at solar thermal facilities. That is, peak generation is shaved, and the generation is shifted to later hours.[11] Hydro reservoirs are used to shift generation across days within the month. Our treatment of hydro is conditional on the type of flow distinguished as follows. First, we determine an exogenously specified calendar of hourly minimum flows from the hydro resource, and therefore a residual amount of flow that can be stored. Second, this remaining hydro flow can be shifted across hours at no efficiency loss. Third, the pumped hydro capacity can also be used to shift generation across hours, but at an efficiency loss. It is these second and third types of flow that are scheduled to minimize solar PV and wind curtailment within each month. Except for the efficiency loss–which requires extra expenditures on generation–we do not include any cost of storage in our calculation of system cost. That is, our calculation is as if the storage capacities were a free endowment and there were no variable costs of doing the storage. Note that the storage capacity is the same across all portfolios examined.

Tables 9 and 10 report the dispatch results for the two sets of alternative portfolios. The tables only show generation for nuclear, solar, wind and natural gas combined-cycle units along with generation and consumption from hydro and battery storage since these are the only items allowed to vary across the alternative portfolios.

Row [18] in both tables shows the net generation from the 3 low carbon technologies: i.e., actual total generation from nuclear, wind and solar minus total losses from storage. Within each table, this net generation is approximately identical. This implies approximately identical aggregate generation from the combined-cycle units, which is verified by an inspection of row [5] in each table. Row [19] in both tables shows the net generation from the 4 technologies: i.e., actual total generation minus total losses from storage. This is also,

[9] Our assumed annual hourly profile of these is based on the historical profiles from 2014-2017

[10] Given our assumptions, coal is always the most expensive resource to dispatch. Therefore, assuming the system has sufficient other capacity, coal generation is always zero. As specified, there turn out to be a materially insignificant number of hours in which coal units are dispatched. Therefore, in the discussion we elide this fact.

[11] This does not imply that the batteries need to be integrated with the solar PV system, as salt storage must be integrated with a solar thermal generator. The batteries are attached to the grid and could be charged and discharged without regard to the output at any solar PV unit. However, we model their use as if it were optimal to respond to aggregate PV generation this way.

Table 9: Minimum Cost Dispatch Results for Alternative Capacity Portfolios Benchmarked to 1 Nuclear Plant Life Extension

	(GWh)	[A] N1	[B] S1	[C] W1	[D] SW1	[E] WS1
	Generation, Actual					
[1]	Nuclear	7,485	0	0	0	0
[2]	Solar	87,287	96,079	86,637	93,244	88,645
[3]	Wind	64,277	63,797	73,373	66,612	70,971
[4]	Subtotal	159,049	159,875	160,010	159,855	159,616
[5]	Combined-cycle	83,736	83,735	83,730	83,739	83,735
[6]	Total	242,785	243,611	243,740	243,594	243,351
	Curtailment					
[7]	Nuclear	774	0	0	0	0
[8]	Solar	1,922	4,056	2,572	3,476	2,698
[9]	Wind	658	1,138	1,092	1,096	1,052
[10]	Total	3,354	5,194	3,664	4,572	3,750
	Storage Generation					
[11]	Pumped Hydro	-15,389	-18,065	-18,500	-18,019	-17,234
[12]	Batteries	-4,310	-4,541	-4,606	-4,503	-4,466
	Storage Consumption					
[13]	Pumped Hydro	10,772	12,645	12,950	12,613	12,064
[14]	Batteries	3,918	4,128	4,187	4,094	4,060
	Storage Losses					
[15]	Pumped Hydro	4,617	5,419	5,550	5,406	5,170
[16]	Batteries	392	413	419	410	406
[17]	Total	5,009	5,832	5,969	5,815	5,576
	Generation, Net					
[18]	Subtotal, N+S+W-losses	154,041	154,043	154,041	154,040	154,040
[19]	Total, N+S+W+CC-losses	237,776	237,778	237,771	237,779	237,775
[20]	GHG Emissions (MtCO2eq)	30.71	30.71	30.71	30.71	30.71

Notes:

[1]-[3] = Output of minimum cost dispatch, including optimized storage.
[4] = [1]+[2]+[3].
[5] = Output of minimum cost dispatch, including optimized storage.
[6] = [4]+[5].
[7]-[9] = shortfall of actual generation in [1]-[3] relative to potential (see earlier table).
[10] = [7]+[8]+[9].
[11]-[14] = Output of minimum cost dispatch, including optimized storage.
[15] = [13]−[11].
[16] = [14]−[12].
[17] = [15]+[16].
[18] = [4]−[17].
[19] = [6]−[17].
[20] = Output of minimum cost dispatch, including optimized storage.
Note since emissions from cogeneration plants are recorded under industrial sector, we exclude them in this total.

Table 10: Minimum Cost Dispatch Results for Alternative Capacity Portfolios Benchmarked to 7 Nuclear Plant Life Extensions

	(GWh)	[A] N7	[B] S7	[C] W7	[D] SW7	[E] WS7
	Generation, Actual					
[1]	Nuclear	46,130	0	0	0	0
[2]	Solar	87,189	148,831	80,268	120,024	92,152
[3]	Wind	64,239	53,198	118,408	81,733	107,310
[4]	Subtotal	197,558	202,029	198,676	201,757	199,462
[5]	Combined-cycle	45,217	45,287	45,430	44,477	45,331
[6]	Total	242,775	247,316	244,106	246,234	244,793
	Curtailment					
[7]	Nuclear	12,474	0	0	0	0
[8]	Solar	2,020	148,093	8,942	38,895	12,390
[9]	Wind	696	11,737	9,701	8,934	8,537
[10]	Total	15,190	159,830	18,643	47,829	20,927
	Storage Generation					
[11]	Pumped Hydro	-15,389	-30,011	-19,065	-26,358	-21,587
[12]	Batteries	-4,155	-5,124	-4,330	-5,087	-4,653
	Storage Consumption					
[13]	Pumped Hydro	10,772	21,008	13,346	18,451	15,111
[14]	Batteries	3,778	4,658	3,937	4,624	4,230
	Storage Losses					
[15]	Pumped Hydro	4,617	9,003	5,720	7,908	6,476
[16]	Batteries	378	466	394	463	423
[17]	Total	4,995	9,469	6,113	8,370	6,899
	Generation, Net					
[18]	Subtotal, N+S+W-losses	192,563	192,560	192,563	193,387	192,563
[19]	Total, N+S+W+CC-losses	237,780	237,847	237,993	237,864	237,894
[20]	GHG Emissions (MtCO2eq)	16.57	16.60	16.64	16.30	16.61

Notes:
[1]-[3] = Output of minimum cost dispatch, including optimized storage.
[4] = [1]+[2]+[3].
[5] = Output of minimum cost dispatch, including optimized storage.
[6] = [4]+[5].
[7]-[9] = shortfall of actual generation in [1]-[3] relative to potential (see earlier table).
[10] = [7]+[8]+[9].
[11]-[14] = Output of minimum cost dispatch, including optimized storage.
[15] = [13]−[11].
[16] = [14]−[12].
[17] = [15]+[16].
[18] = [4]−[17].
[19] = [6]−[17].
[20] = Output of minimum cost dispatch, including optimized storage.
Note since emissions from cogeneration plants are recorded under industrial sector, we exclude them in this total.

by definition, the net demand served by these 4 technologies. As one can see, the values in row [19] are all approximately identical to one another, not only within each table, but also across tables. This is a required property of the dispatch algorithm: the only variation across the portfolios is how much of the demand is served by each technology. Together, the four must serve the same net demand. As shown in row [20], the alternative portfolios within each table have identical or approximately identical GHG emissions.[12]

Comparing the GHG emissions in the Baseline portfolio shown in Table 6 against the GHG emissions in these two sets of alternative portfolios, we see emissions fall from 33.46 MTCO2eq with no nuclear plants, to 30.71 MT with 1 nuclear life extension (a reduction of 8%), to 16.57 MT with 7 nuclear life extensions (a total reduction of 42%).[13]

In discussing our alternative portfolios, we started from the Baseline portfolio and added different amounts of capacity for the various low carbon technologies. We carefully finessed any discussion of how much to reduce the natural gas combined-cycle capacity. This was purposeful. As the capacity of the other technologies is increased, it is not necessarily the case that capacity of the combined-cycle technology is decreased proportionally. First, the system is already endowed with a large volume of underutilized combined-cycle capacity as shown in Table 1. Our Baseline scenario assumes a small reduction of this capacity by 2030, as shown in Table 6. So, when our alternative portfolio install either nuclear, solar PV or wind capacity to squeeze out the combined-cycle generation, it does not necessarily squeeze out the capacity. The system is already endowed with that capacity. Squeezing some of it out means retirements of installed capacity and not simply avoided investments in new capacity. The savings from retirement and different from the savings from avoided investments, and therefore the decision to retire capacity is different from the decision not to invest in new capacity. Second, as indicated earlier, the actual choice of total capacity is shaped by more than simply the amount of generation required to serve our scenario for load.

[12] More precisely, emissions are determined by the particular composition of generation from the fleet of combined-cycle units which have different thermal efficiencies and therefore emissions factors. An aggregate level of generation that is divided evenly across many hours will make use primarily of the most efficient units, whereas an aggregate level that is concentrated in fewer hours will shift some generation to the less efficient units, resulting in different emissions levels for the same aggregate generation. Our dispatch model has some information on these different efficiencies and so we can calibrate to an exactly identical emissions level, but for the sake of this discussion, we disregard that.

[13] Although our portfolio with 7 nuclear life extensions, N7, is very similar to the Base Case considered by the Commission of Experts (2018) and shown in Table 4, our dispatch has notably higher GHG emissions. Comparing Table 10 against Table 4 we can see that our dispatch has more generation from the combined-cycle units and less from the nuclear plants. We apparently assume that the nuclear units are available in fewer hours than the model employed by the Commission of Experts.

3.3 Cost Inputs

A key input for our system cost calculations are the cost of capacity and generation for nuclear life extensions and for the alternative technologies, solar PV, wind and natural gas combined-cycle technologies. We want costs pertaining to generation in 2030. There will certainly be great disagreement about forecasts for cost numbers at that horizon. We have constructed our analysis in a transparent way so that readers can recalculate the results using their preferred inputs. We believe our main conclusions will hold for a wide range of values, although obviously not for all. We have chosen to present the results primarily using values published by the European Commission's Joint Research Centre's (JRC) (2014) ETRI report and by ENTSO-E's (2017) TYNDP. The ETRI report's forecasted cost values reflect anticipated technology improvements. In the case of the capacity factor for solar PV, we adjust their figure to reflect Spain's favorable insolation relative to other regions of Europe. Where pertinent, we highlight certain other published benchmarks against which these inputs can be compared.

Table 11 shows the inputs, which are all quoted in €$_{2013}$. Rows [1]-[4] of column [A] are the raw inputs for the cost of nuclear life extension, rows [8]-[11] are the inputs for solar PV, rows [14]-[17] are the inputs for wind, and rows [20]-[26] are the inputs for the natural gas combined-cycle, including an attributed cost for GHG emissions.

The €592/kW shown in row [2] is derived from ETRI's €1,076/kW estimate of the costs required for a 15-year life extension of a generic European Generation II plant. We adjusted that figure to correspond to our 10-year life extension as shown in the footnotes. There are two public cost estimates specific to life extensions at Spain's nuclear plants which are lower than ETRI's generic cost figure. The accounting and consultancy firm Pricewaterhouse Coopers Asesores de Negocios (2018) reported an estimated aggregate cost of €3.2-3.5 billion for 10-year life extensions, which translates to €428-468/kW. Iberdrola (2018) reported an estimated aggregate cost of €6-7 billion for 15-year life extensions, which translates to €913/kW. So, this ETRI figure may be conservatively high.

A number of countries have already had experience with investments in life extensions, or with forecasting their costs, and it makes sense to benchmark this estimated cost against that experience. However, this benchmarking is difficult. Many life extension programs are combined with other investments, such as uprating of plants or retrofits required to meet new safety standards post Fukushima, while others are not. The designs and vintage of plants receiving life extensions varies. And, in some cases the investments are made at the 30-year mark, where in other cases they are made in the years leading to the 40-year

Table 11: Inputs for the Cost of Electricity for Nuclear Plant Life Extensions and the Alternative Technologies

		Input [A]		Unit Factor [B]	Present Value Factor [C]	Levelized Cost (€/MWh) [D}
	Nuclear Life Extension					
[1]	Life	10	years			
[2]	Capital Cost (investment)	592	€/kW	0.128	0.142	10.81
[3]	Fixed O&M	90	€/kW/y	0.128	1.000	11.54
[4]	Variable O&M	8.00	€/MWh	1.000	1.000	8.00
[5]	Capacity Factor	89%				
[6]	Discount Rate	7%				
[7]	Total Cost					30.35
	Solar PV					
[8]	Life	25	years			
[9]	Capital Cost (investment)	640	€/kW	0.544	0.086	29.85
[10]	Fixed O&M	10.88	€/kW/y	0.544	1.000	5.91
[11]	Variable O&M	0.00	€/MWh	1.000	1.000	0.00
[12]	Capacity Factor	21%				
[13]	Total Cost					35.77
	Onshore Wind					
[14]	Life	25	years			
[15]	Capital Cost (investment)	867	€/kW	0.476	0.086	35.37
[16]	Fixed O&M	19.067	€/kW/y	0.476	1.000	9.07
[17]	Variable O&M	0.00	€/MWh	1.000	1.000	0.00
[18]	Capacity Factor	24%				
[19]	Total Cost					44.44
	NGCC					
[20]	Life	30	years			
[21]	Thermal Efficiency	62%				
[22]	Capital Cost (investment)	850	€/kW	0.134	0.081	9.20
[23]	Fixed O&M	21.25	€/kW/y	0.134	1.000	2.85
[24]	Variable O&M, excl fuel	2.00	€/MWh	1.000	1.000	2.00
[25]	Fuel Cost	31.68	€/MWh-th	1.613	1.000	51.10
[26]	Emissions Charge	50.00	€/tCO2eq	0.326	1.000	16.29
[27]	Capacity Factor	85%				
[28]	Total Cost					81.44

Notes:

Column [A]

Unless otherwise stated, inputs are from European Commission Joint Research Centre, Institute for Energy and Transport, 2014, Energy Technology Reference Indicator projections for 2010-2050, 2030, cited as ETRI (2014).

[1]: By assumption we are considering a 10-year life extension.

[2] = Future Value of a 10-year payments of 1.9%*4,100*55% using a 7% discount rate. ETRI reports a fixed O&M cost (FOM) for refurbishment of a Generation II reactor equal to 1.9% of the reactor capital cost. It does not report a capital cost for a Generation II reactor, but for Generation III it shows a cost of €4,100/kW. These costs are annual over years 31-40 for a 15-year life extension starting in 41. To translate this to a 10-year life extension cost we use the ratio of a 10-year to a 15-year annuity, which is 55%.

[3] = 2.1%*, per ETRI (2014).

[5]: By assumption.

[6]: By assumption.

[12] and [18]: By assumption, at historical value.

[15] = 1,300*2/3, where €1,300/kW is from ETRI (2014) and 2/3 adjusts for improvements in capacity factor between 2014-2030.

[16] = 28.6*2/3, where €28.6/kW is from ETRI (2014) and 2/3 adjusts for improvements in capacity factor between 2014-2030.

[25] = 8.8/0.27778. ENTSOE's TYNDP DG2030 scenario as reported in Annex II Methodology: Scenario Report gives a fuel price of €8.8/GJ.

[26]: ENTSOE's TYNDP DG2030 scenario as reported in Annex II Methodology: Scenario Report.

[27]: By assumption.

Column [B]

[2]&[3], [9]&[10], [15]&[16], [22]&[23] = 1/(CapacityFactor*8,760).

[25] = 1/ThermalEfficiency = 1/[A16]

[28] = 56,100*0.001*0.0036/ThemalEfficiency=.20196/[A16]. MAPAMA (2017) reports the CO2 intensity of natural gas as 56,100 kgCO2/TJ thermal.

Column [C]

[2] = 10-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A1])/[A5]

[9] = 25-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A8])/[A5]

[15] = 25-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A14])/[A5]

[22] = 30-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A20])/[A5]

Column [D]

[2], [3] & [4], [9] [10] & [11], [15], [16] & [17], and [22]-[26] = [A] * [B] * [C].

mark. Nevertheless, we relate here NEA's (2012b) summary of some of that information for comparison:

- In the United States, 73 of 104 plants had already received licenses for 20-year life extensions by the date of publication. The authors provide a range of $750-1,000/kW, based upon the results of an Electric Power Research Institute survey. For a very rough comparison, we translate this at 0.75 €/$, which produces a range of €563-750/kW. It must be recognized, however, that the wave of life extensions in the U.S. coincided as well with investments to uprate many of the plants. The authors make no effort to untangle the costs for a simple life extension and the cost of the uprate. That would perhaps be an impossible task.

- In Belgium, studies made in 2008-9 and 2011 estimated the cost of a 10-year life extension for the three oldest reactors at €650/kW; ultimately, the 2013 decision to extend the life of the Tihange 1 reactor included an investment commitment of €624/kW, and the 2015 decision to extend the life of the Doel 1 and 2 units was said to require an investment of €808/kW–see Reuters (2013) and Agentschap Belga (2015)

- In France, assessments of the cost of life extensions have been made by EDF and reviewed by the Cour des Comptes in advance of the NEA (2012b) report led the NEA to quote an overnight cost of €875/kW, which includes expenditures on deferred maintenance, safety upgrades following Fukushima, and performance improvements, and which may enable life extensions between 10 and 20 years. Subsequent reports by EDF (2018) and the Cour des Comptes (2016) have given larger figures but still including diverse components. RTE (2017) uses a figure of €600/kW for life extensions.

- In Hungary, a program for a 10-year life extension of the four VVER-440 reactors at the Paks plant (i.e., from 30 years to 40) was budgeted at between €533-570/kW overnight cost in 2011 euros.

- In Korea, the 10-year life extension of the Kori 1 unit (i.e., from 30 to 40 years) cost $317/kW.

- The NEA estimated the cost of life extension for Swiss reactors $490-650/kW, or roughly €367-488/kW.

The values for a nuclear plant's fixed OM and variable OM are taken from the European Commission's Joint Research Centre. ETRI's values do not include personnel or fuel costs, which should then be added to these figures. However, comparing these figures against those reported in the IEA/NEA (2015) suggests they are reasonable at this level.

The values used for cost inputs should reflect actual costs and not reflect taxes or subsidies. Indeed, this is the basis on which ETRI reports costs. Therefore, these costs will not reflect Spain's fuel tax. Also, these costs should reflect a lower value for waste disposal than Spain's charge to existing reactors.[14]

For solar PV, the inputs in rows [8]-[11] are taken directly from ETRI (2014). For wind, ETRI forecasts that technological improviements in turbines to 2030 will enable a 50% increase in the full-load hours equivalent potential capacity factor. That is, a 1 MW unit of 2030 vintage capacity will be capable of producing 50% more generation than 1 MW of 2013 vintage capacity. Rather than keep track of different vintages of capacity, we choose to report our results standardized for a 1 MW unit of 2013 capacity. and therefore we have scaled the cost inputs for the wind technology to 2/3 of the values reported by ETRI (2014) to reflect the technological improvement.

For natural gas combined-cyle, ETRI (2014) estimates a thermal efficiency in 2030 of 62%, which is much higher than Spain's current combined-cycle units. Our natural gas price input of €31.68/MWh thermal, is from ENTSO-E's (2017) TYNDP DG2030 scenario. This also matches the input used for the Commission of Experts' (2018) Base Case scenario. This is a high value compared to recent natural gas prices. We structure our calculation so that it is simple to substitute in a different value for the natural gas price and see the impact on results. Our emissions price input of €50/tCO2eq is also from ENTSO-E's (2017) TYNDP DG2030 scenario and used in the Commission of Experts' (2018) report. Here, too, we structure the analysis in a transparent way so that the reader can substitute an alternative value.

3.4 A Simple LCOE Comparison of Technologies

A popular and widely cited metric for evaluating investment choices across alternative generation technologies is the Levelized Cost of Electricity (LCOE). The LCOE is a type of average cost across the hours of electricity delivered. The average is calculated using a discount rate

[14] Spain currently assesses a charge of €6.69/MWh to go to the fund for financing activities of the General Plan for Radioactive Waste (PGGR) to cover management of waste and dismantling of the plants. This value was last set in 2010 and is based on estimates of future costs as well as on estimates of future generation from the plants. The report from the Commission of Experts (2018) discusses the adequacy of this fund under alternative scenarios for the life of the existing reactors. Extending the life of existing reactors improves the adequacy of the fund precisely because the level of the fee is not equal to the marginal cost of additional waste.

to reflect the time value of money and risk. The LCOE is a handy and useful metric when properly applied to certain narrowly circumscribed choices–such as two technologies intended to serve the same market segment. However, it is too crude to apply indiscriminately. The difficulty in applying the LCOE arises because of the diverse array of services required by any electricity system. A single metric like the LCOE suggests that every unit of electricity is like every other unit of electricity, in which case an average cost is informative. In reality, however, every unit is not like every other unit. A typical example is the difference between peak and off-peak load. It is more expensive to serve peak load because it requires capital investments that are amortized across fewer hours of the year. Another example is the load that ramps quickly up or down at certain hours of the day. It requires investment in specialized fast ramping capable technologies that are usually more expensive per unit of electricity delivered. Other typical examples involve ancillary services, such as frequency regulation, reactive power or fast acting reserves. Consequently, electricity systems usually consist of investments in a portfolio of technologies that together provides the full array of services at lowest cost. Technologies with high LCOEs coexist alongside technologies with low LCOEs because they serve different portions of load, and the cost differential is inherent in serving them. Indeed, different units of the same technology are often used to serve different loads and therefore operate with different LCOEs.

That proviso notwithstanding, LCOEs are widely referenced benchmarks and many analysts report their estimate of costs in the form of an LCOE. Therefore, in presenting our initial inputs on costs, we translate them into LCOEs. In addition, we do an initial calculation of the difference in system costs using these LCOEs as a crude estimate. From there, we move on to a more detailed look at system costs that takes into account the time profile of demand and renewable resources and the use of the technologies in a full portfolio that serves the full load.

To calculate the LCOEs, we need an assumed capacity factor for each technology. For our system cost analysis, the capacity factor will not be an input, but rather an output of a minimum cost dispatch algorithm. However, for this benchmarking purpose, the capacity factor is an input as shown in Table 11 column [A] at rows [5], [12], [18] and [27] based on historical experience. To calculate the LCOEs, we also need a discount rate which is shown in column [A] at row [6]. Columns [B]-[D] translate the inputs from Column [A] into levelized costs. Column [B] gives the factor used to allocate a fixed input cost across units of annual generation based on the assumed capacity factor. Column [C] gives the present value factor which adjusts the allocation to incorporate the time value of money over the time horizon of

Table 12: Using the LCOE to Calculate the Aggregate Annual Savings from Nuclear Life Extensions Relative to Each Alternative

		[A] Nuclear	[B] Solar PV	[C] Wind	[D] Natural Gas
[1] LCOE		30.35	35.77	44.44	81.44
[2] Capacity Factor		89%	21%	24%	85%
Cost of Generation Scaled to 1 Nuclear Life Extension					
[3] Capacity	(MW)	1,003	4,251	3,719	1,050
[4] Generation	(GWh)	7,820	7,820	7,820	7,820
[5] Incremental System Cost, gross annual	(€ millions)	237	280	348	637
[6] Incremental System Cost, gross PV 10 years	(€ millions)	1,667	1,964	2,441	4,473
[7] Difference to Nuclear	(€ millions)		298	774	2,806
[8]			18%	46%	168%
Cost of Generation Scaled to 7 Nuclear Life Extensions					
[9] Capacity	(MW)	7,117	30,163	26,392	7,452
[10] Generation	(GWh)	55,487	55,487	55,487	55,487
[11] Incremental System Cost, gross annual	(€ millions)	1,684	1,985	2,466	4,519
[12] Incremental System Cost, gross PV 10 years	(€ millions)	11,828	13,939	17,320	31,737
[13] Difference to Nuclear	(€ millions)		2,111	5,492	19,909
[14]			18%	46%	168%

Notes:
[1] & [2] from Table 11.
[3A]: Given as the capacity of the 1 nuclear plant.
[4A] = [3A]*8.76*[2A].
[4X] = [4A].
[3X] = [4X]/(8.76*[2X]).
[5] = [4]*[1].
[6] = PV(7%,10,-[5]).
[7X] = [6X]-[6A].
[8X] = [7X]/[6A].
[9A]: Given as the capacity of 7 nuclear plants.
[9X]-[14] follow same logic as [3X]-[8].

generation. Column [D] shows the levelized cost for each component, which is the product of columns [A], [B] and [C], and a total levelized cost.

Table 12 translates these unit costs into an aggregate savings from extending the life of nuclear plants. Rows [1] and [2] are the inputs taken from Table 11. We then calculate savings for two scenarios. In the first scenario we evaluate the generation from 1 nuclear life extension, and compare costs for investments into alternative capacities that produce the same amount of generation given the assumed capacity factors. The capacity of the 1 nuclear life extension is input to row [3], and the resulting generation is in row [4]. By assumption, the generation for the other technologies in row [4] is set equal to this amount, and we back out the required capacities in row [3] based on the assumed capacity factors. The annual cost for each technology equals the LCOE in row [1] times the generation in row

[4]. Row [5] translates this to a present value of the full 10 years of savings. The fact that the nuclear LCOE is the lowest among all of the alternatives translates linearly into the annual savings and the present value of the 10 year's of operation. Row [7] shows how much more expensive are each of the other technologies, and row [8] expresses this as a percent increase in cost. The percentages in row [8] exactly match the amount by which the LCOEs for each technology exceed the LCOE of nuclear. The second scenario evaluates the generation from 7 nuclear life extensions.

Using the assumptions in the LCOE calculation, a single nuclear life extension saves €298 million relative to the needed investment for comparable solar PV generation, and save €774 million relative to the needed investment for comparable wind generation. The set of 7 nuclear life extensions saves €2.111 billion relative to the needed investment for comparable solar PV generation, and save €5.492 billion relative to the needed investment for comparable wind generation.

The problem with the calculations in Table 12 stem from taking the LCOE as fixed, which in turn stems from treating the capacity factors as fixed and exogenously specified. The correct capacity factors depend on how the capacity of each technology sits within a full portfolio of capacities. The correct capacity factors are endogenously determined as a result of an optimal dispatch given a specified portfolio of capacities. These will differ across the set of alternative portfolios chosen. We now turn to that system cost calculation.

3.5 System Cost Results

We compare system costs across the various alternative portfolios in two steps. First, we compare the system costs within each of our two sets of alternative portfolios. Within each set, the total GHG emissions are constant, so that a comparison across the portfolios within the set answers which portfolio is the cheapest way to achieve the targeted GHG emission reductions. Second, we compare across the sets–that is, moving from the Baseline portfolio to the cheapest portfolio benchmarked to 1 nuclear plant life extension, or from the Baseline portfolio to the cheapest portfolio benchmarked to 7 nuclear plant life extensions. This comparison tells us the cost of achieving the targeted reductions.

Table 13 shows the calculation of the cost of the incremental low carbon capacity and generation for the first 5 alternative portfolios:

- row [1] is the incremental low-carbon capacity for each portfolio relative to the Baseline portfolio;

Table 13: Relative System Costs for Incremental Low Carbon Generation from Alternative Portfolios Benchmarked to 1 Nuclear Plant Life Extension

		[A] N1	[B] S1	[C] W1	[D] SW1	[E] WS1
[1] Incremental Capacity	(MW)	1,003	5,775	4,550	5,283	4,503
[2] Incremental Low Carbon Generation, N+S+W	(GWh)	7,492	7,494	7,493	7,491	7,491
[3] Incremental Capacity Factor		85%	15%	19%	16%	19%
[4] Incremental Unit Cost	(€/MWh)	31.33	50.70	56.74	51.27	52.01
[5] Incremental System Cost, gross annual	(€ millions)	235	380	425	384	390
[6] Incremental System Cost, gross PV 10 years	(€ millions)	1,649	2,669	2,986	2,698	2,737
[7] Difference to Nuclear	(€ millions)		1,020	1,337	1,049	1,088
			62%	81%	64%	66%

Notes:

[1]

[A]= Table 7 [1A] − Table 6 [1A].

[B]= Table 7 [2B] − Table 6 [4A].

[C]= Table 7 [3C] − Table 6 [3A].

[D]= (Table 7 [2D]+[3D]) − (Table 6 [3A]+[4A]).

[E]= (Table 7 [2E]+[3E]) − (Table 6 [3A]+[4A]).

[2]= Table 9 [18] − Table 6 [19C].

[3]= [2]/([1]*8.760).

[4]= calculated using levelized cost formulas in Tables 11, substituting the capacity factor from [3].

[5]= [2]*[4]/1,000.

[6]= PV(7%,10,-[5]).

[7X]= [6X]-[6A].

- for column [A] it is the 1,003 MW capacity of the 1 nuclear plant obtaining a life extension;
- for column [B] is the the 5,775 MW of additional solar PV capacity over the Baseline portfolio's solar capacity;
- for column [C] it is the 4,550 MW of additional wind capacity over the Baseline portfolios' wind capacity;
- for columns [D] and [E], it is the combined incremental capacity of solar PV and wind generation over the Baseline portfolio's combined capacity;

- row [2] is the incremental low-carbon generation for that portfolio over the low-carbon generation in the Baseline Portfolio; this reflects the impact of dispatch, including curtailment as shown in Table 7; so, when there is increased renewable capacity, nuclear is dispatched less often and there is also increased curtailment of both solar PV and wind;

- row [3] is the capacity factor for this incremental capacity; in each case, we calculate the capacity factor incorporating the total net impact on generation from all low carbon technologies and compare that against the potential generation from the increased capacity;

- row [4] is the average unit cost for this generation given this capacity factor, and assuming the same pattern of generation for the full 10-year life extension for the nuclear and 25-years for the wind and solar;[15] Note that providing generation using nuclear has the lowest unit cost among these 5 alternative portfolios.

- row [5] is the incremental gross annual system cost associated with this incremental capacity; this does not reflect any savings from displaced natural gas combined-cycle capacity and generation, which will be discussed later; it simply asks what is the annual cost of this incremental generation produced with this capacity;

- row [6] calculates the present value of this annual cost over the 10-year life extension. Note that the alternative of the nuclear plant life extension is the lowest system cost, by far.

[15]That is, this is a static analysis that uses 2030 as a representative year. This ignores dynamic factors.

- row [7] calculates for each of the alternatives besides nuclear the difference between the alternative's gross incremental system cost and the nuclear alternative's gross incremental system cost.

The table does not show any of the savings from avoided natural gas combined-cycle capacity or operating expenses, which is why we refer to it as a gross cost. The proper calculation of required system capacity is complicated. It needs to incorporate an assessment of risk over a variety of variables, including demand, resource availability, and the reliability of each type of capacity, among others. Our calculations are based entirely on the single forecast scenario we used, which is not the basis for setting a minimum capacity. We could have utilized Spain's current methodology for calculating the coverage index, but it is debatable whether the same derating factors and index formula should be utilized for a 2030 system that is so dramatically different from today's. We note that inclusion of capacity adequacy considerations almost certainly make our results an underestimate of the relative cost efficiency of nuclear life extensions. Nuclear units almost certainly enter favorably into any capacity adequacy calculation, on par with natural gas units, whereas both solar and wind capacity is likely to be subject to a significant derating. The resource factors highlighted in our calculation are likely to bear out in any capacity adequacy calculation, too.

The bottom line from Table 13 is that among the 5 alternative portfolios that reduce GHG emissions for the electricity sector down to 30.71 MTCO2eq from the Baseling portfolio's 33.46, the alternative of extending the life of 1 nuclear plant yields the lowest system cost. Extending the life of 1 nuclear plant saves a little more than €1 billion relative to the alternative of expanding the scale of solar PV penetration, and saves more than double that relative to the alternative of expanding the scale of wind penetration.

Table 14 shows the calculation of the cost of the incremental low carbon capacity and generation for the next 5 alternative portfolios relative to the Baseline portfolio:

- row [1] is the incremental low-carbon capacity for each portfolio relative to the Baseline portfolio;
  - for column [A] it is the 7,117 MW capacity of the 7 nuclear plants obtaining a life extension;
  - for column [B] it is the 109,800 MW of additional solar PV capacity;
  - for column [C] it is the 30,160 MW of additional wind capacity;
  - for columns [D] and [E], it is the combined incremental capacity of wind and solar PV;

Table 14: Relative System Costs for Incremental Low Carbon Generation from Alternative Portfolios Benchmarked to 7 Nuclear Plant Life Extension

		[A] N7	[B] S7	[C] W7	[D] SW7	[E] WS7
[1] Incremental Capacity	(MW)	7,117	109,800	30,160	49,134	32,411
[2] Incremental Generation	(GWh)	46,015	46,011	46,014	46,838	46,014
[3] Incremental Capacity Factor		74%	5%	17%	11%	16%
[4] Incremental Unit Cost	(€/MWh)	34.96	157.02	61.24	76.27	60.95
[5] Incremental System Cost, gross annual	(€ millions)	1,609	7,225	2,818	3,572	2,804
[6] Incremental System Cost, gross PV 10 years	(€ millions)	11,298	50,743	19,793	25,091	19,697
[7] Difference to Nuclear	(€ millions)		39,446	8,495	13,794	8,399
			349%	75%	122%	74%

Notes:
[1]
[A]= Table 8 [1A] – Table 6 [1A].
[B]= Table 8 [2B] – Table 6 [4A].
[C]= Table 8 [3C] – Table 6 [3A].
[D]= (Table 8 [2D]+[3D]) – (Table 6 [3A]+[4A]).
[E]= (Table 8 [2E]+[3E]) – (Table 6 [3A]+[4A]).
[2]= Table 10 [18] – Table 9 [18].
[3]= [2]/([1]*8.760).
[4]= calculated using levelized cost formulas in Tables 11, substituting the capacity factor from [3].
[5]= [2]*[4]/1,000.
[6]= [5] + Table X [5].

- row [2] is the incremental low-carbon generation for that portfolio over the low-carbon generation in the Baseline Portfolio;
- the remaining rows are calculated similarly to Table 13.

Comparing the incremental unit cost of each technology relative to the respective incremental unit costs in Table 13, we can see that for all of the technologies as the scale of capacity for that technology increases, the incremental unit cost increases. This is natural because all technologies face the same load duration curve which requires that at some point as the scale of aggregate capacity increases, some capacity must be operated at lower capacity factors. This is true for nuclear as well as for the renewable alternatives. The correlation between the time profile of renewable resource factors and load is also at work. In particular, it is clear from the table that the incremental capacity factor of the solar PV technology falls particularly fast with the scale of capacity. Even at the expanded scale of 7 nuclear plant life extensions, the system cost of incremental nuclear capacity is the lowest cost option.

The bottom line from Table 14 is that among the 5 alternative portfolios that reduce GHG emissions for the electricity sector down to 16.57 MTCO2eq from the Baseling portfolio's 33.46, the alternative of extending the life of 7 nuclear plant yields the lowest system cost. Extending the life of 1 nuclear plant saves a little more than €1 billion relative to the alternative of expanding the scale of solar PV penetration, and saves more than double that relative to the alternative of expanding the scale of wind penetration.

Our calculation treats 2030 as a representative year and abstracts from issues related to the path before and after.[16]

3.6 Savings on Combined-Cycle Generation and Capacity Costs

Table 15 shows the savings on avoided combined-cycle generation and capacity, under the assumption that nuclear generation and capacity displace 1-for-1 combined-cycle generation and capacity. Row [1] is the avoided generation, i.e., the nuclear generation in the two alternative portfolios. Rows [2], [4] and [6] are different components of the combined-cycle's unit cost. Rows [3], [5] and [7] translate these unit costs to annual cost components. Row [8] is the total avoided cost of generation and capacity from combined-cycle units. Row [9]

[16]So, for example, we do not consider any costs or benefits associated with adapting the timing of plant closures to accommodate the throughput capacity of the dismantling operation, and we do not consider the longer-term profile of capacity utilization of other technologies, such as the combined-cycle plants, as decarbonization targets tighten over time. These issues play a role in some of the recommendations from the Commission of Experts (2018).

Table 15: Savings on Avoided Combined-Cycle Generation and Capacity

			[A] N1	[B] N7
[1]	Avoided Generation	(GWh)	7,491	46,009
[2]	Unit Variable O&M Cost, incl fuel, excl CO2	(€/MWh)	59.60	59.60
[3]	Avoided Variable O&M Cost	(€ millions)	446	2,742
[4]	Unit Fixed O&M Costs	(€/MWh)	2.85	2.85
[5]	Avoided Fixed O&M Cost	(€ millions)	21	131
[6]	Unit Capital Costs	(€/MWh)	9.20	9.20
[7]	Avoided Capital Costs	(€ millions)	69	423
[8]	Avoided Cost, total	(€ millions)	537	3,297
[9]	Incremental System Cost, gross annual	(€ millions)	235	1,609
[10]	Incremental System Cost, net annual	(€ millions)	-302	-1,688

is the gross annual incremental system cost for each of the two alternative portfolios, which are taken from Tables 13 and 14. Since the gross annual incremental system costs of the nuclear capacity is less than the avoided cost of the combined-cycle units, the net incremental system cost is negative. That is, even disregarding CO2 which was not incorporated into this calculation, it makes sense to invest in nuclear life extensions. The savings on combined-cycle generation and capacity is greater than the cost of nuclear generation and capacity.

We broke the calculation into the components to make it easier to evaluate the results under alternative assumptions. Since the combined-cycle capacity is already in place, retiring the capacity does not save on the capital cost. Therefore, the calculation can be redone zeroing out rows [6] and [7]. As it happens, given that ENTSOE's (2017) TYNDP DG2030 scenario has such a high natural gas price, the savings on the variable operating cost in row [3] are alone sufficient to outweigh the cost of generation and capacity from nuclear life extensions. Comparing row [9] against row [3] reveals that the forecasted natural gas price would have to fall below €17/MWh before the avoided cost of combined-cycle generation fell below the incremental system cost of the nuclear generation and capacity.

4 Conclusion

Between now and 2030, Spain must decide whether to retire each of its seven operating nuclear plants, or whether to extend their lives for some additional number of years. In this paper we considered 10-year life extensions. We have calculated the system cost of alternative portfolios of capacity making use of nuclear or replacing it with solar PV or wind capacity or some combination of the two. For two levels of GHG emission reductions, we showed that nuclear life extensions provide the lowest system cost. In addition, for a wide range of potential natural gas prices, the system cost of nuclear life extensions is less than the cost of continuing to use natural gas combined-cycle plants to replace nuclear's generation.

The focus of our analysis has been on the time profile of demand over the hours of the year and the correlation with the time profile of renewable resource availability. Our results demonstrate that the further penetration of renewables forecasted for Spain to 2030 makes the problem of curtailment an important determinant of system costs.

Some important determinants of system cost have not been included in our analysis. Importantly, we have not incorporated the difficult issues of operating constraints on the nuclear plants and how these are to be meshed with a system including a high volume of renewable capacity, and that is a topic we are now exploring. Alongside that, we are exploring further ways to optimize the use of storage capacity to reduce curtailment. We have only analyzed a single scenario for demand and resource factors, and calculated the system cost of matching supply with demand under that scenario. Others, such as Rivier et al. (2018) have explored a range of scenarios. We think our focus on comparing the total system cost is a valuable complement to technical comparisons of feasible options as in Greenpeace (2018) and to expositions of the many other dimensions that distinguish options as in the Commission of Experts (2018).

In our analysis of system cost, we have focused on the social cost. We have not focused on the market design and fiscal regime that determine the final remuneration of operators of the plants. Most of Spain's recent investments in renewable capacity have required remuneration on top of the price of energy paid in the Spanish wholesale market. Analysts such as the Commission of Experts (2018) and Rivier et al. (2018) have pointed out the need for significant capacity payments in order to compensate investments in capacity, such as needed investments in combined-cycle units. Spain's nuclear units are further disadvantaged by fiscal rules that levy extra charges or charges above actual social costs. It is entirely possible that nuclear plant life extensions are the most cost effective alternative, but current market structures do not remunerate plant owners commensurately. Haratyk (2017) demonstrated this mismatch in the current environment in the U.S.. We have already seen in the case of Spain's Garoña plant that disputes about remuneration can undermine realizing the value of nuclear plant life extensions. This is an important and difficult issue to explore.

Reducing GHG emissions is an urgent priority–for Spain, for the EU and for mankind.

Our results demonstrate that extending the life of Spain's nuclear plants is the most cost effective way to do that. Indeed, nuclear plant life extensions help reduce the cost of achieving deeper reductions.

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