WWF

ECONOMIC
& TECHNICAL
ASSESSMENT

FEBRUARY
2015

CLEAN ALTERNATIVES TO PTOLEMAIDA V

Economic and technical assessment

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The aim of this report is to investigate and offer an economic evaluation of alternative solutions to the planned construction of the Ptolemaida V lignite plant - solutions that are based on Renewable Energy Sources (RES). The role that small and large-scale storage technologies can play in increasing the RES share in Greece's energy mix is also examined.

A new energy landscape

It's been quite a few years since the decision to build Ptolemaida V was taken - the invitation to tender was approved in 2010 -, in a time when the status quo in climate and energy policy, both in Greece and abroad, was notably different than it is today. Key to the recent developments at an international level have been the successive decisions by the USA, China and the European Union to take important measures towards reducing their emissions. These political changes have also affected the attitude of international financial institutions, as one after another, they are placing strict conditions on funding the construction of new coal plants. Quite significantly, the European Investment Bank recently decided to end funding towards coal plants whose emissions exceed 550 gr CO_2/Kwh, ruling out in this way Ptolemaida V, which is expected to emit twice as much.

It appears that this change of wind is grasped by Europe's energy giants, which are gradually changing their business plans. Companies such as E.On, RWE, EnBW and EDP have decided to cut down their activity in the fossil fuel sector and turn towards new areas of profit, in RES and decentralized production, networks and energy services sectors.

The aforementioned become of multi-fold importance to Greece, due to the devastating economic situation of the country, as well as the Public Power Corporation's (PPC) limited liquidity. The bleak outlook for Ptolemaida V, a €1.4b project, is further deteriorated by two main factors: a) the expected increase in CO_2 emission allowances costs, particularly following the implementation of the Market Stability Reserve mechanism that was proposed by the European Commission in the beginning of 2014 and b) the strong possibility of a reduction in the hours of operation of the new unit as a result of RES growth, according to the current national energy plan. The effect of these two factors has been examined in a previous study by WWF Greece[1].

Economically efficient alternatives to Ptolemaida V

In the first stage of the current study, a comparison was made between the levelised cost of electricity of various electricity production technologies (LCOE)[2], which concluded that <u>certain RES technologies are already fully competitive with conventional electricity production technologies, and specifically Ptolemaida V.</u>

This trend is expected to grow in the future, as the development of clean technologies will make RES even cheaper. At the same time, the cost of electricity produced in lignite plants is expected to increase for a number of reasons, such as for example the high CO_2 emission rights costs and increasing fuel costs. The questionable return of the Ptolemaida V investment is also directly linked to the uncertainty regarding the initial installation cost of the unit. Figure 1 presents sample results of the comparison made between Ptolemaida V and wind and photovoltaic (PV) units up until 2050, demonstrating the competitiveness of land wind farms and medium and large PV stations with regards to the new lignite plant.

[1] WWF Greece. (2013). "Ptolemaida 5 and Meliti 2, Economic viability report of the new lignite plants".
[2] This method aims at calculating the overall production cost per electricity production technology throughout its lifespan, in net present value.

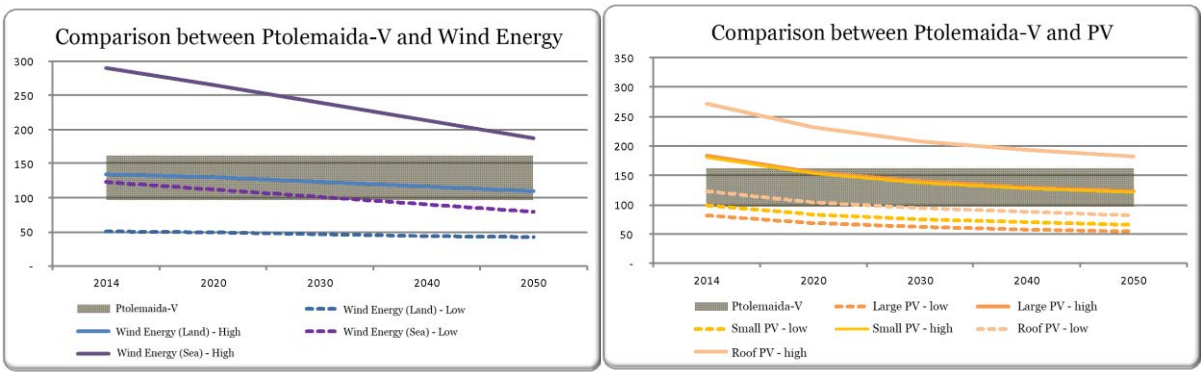


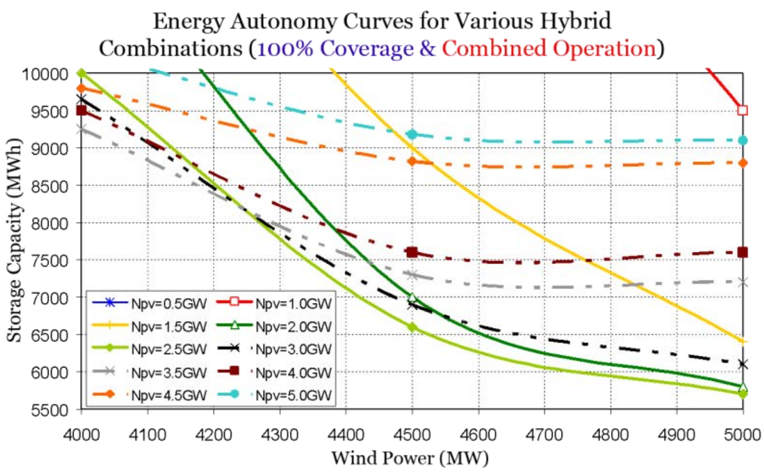
Figure 1. Levelised cost comparison between Ptolemaida V and selected RES technologies

Assessment of hybrid RES and pumped hydro energy storage systems

Based on the aforementioned facts, it is essential to investigate RES-based alternatives to the construction of Ptolemaida V. The greatest challenge that RES technologies face in meeting base load demands similar to those of Ptolemaida V, is the variable nature of the energy production using wind and PV systems. However, this challenge can be technically overcome by combining RES production with various energy storage systems, such as batteries and pumped hydro energy storage (PHES).

The current study focused on the potential for substituting Ptolemaida V with hybrid systems that combine PHES units and wind and PV stations. A previous study[3] has already demonstrated that the conversion of seven pairs of the PPC's existing hydroelectric power (HP) plants to PHES units is technically feasible and economically attractive, given that it eliminates the need for constructing new reservoirs. This option will also result in minimal environmental impacts.

The energy analysis performed in the current study proved that it is possible to meet the base load demands of Ptolemaida V using hybrid combinations of PHES, wind and photovoltaic stations (Figure 2). Should *almost full* coverage (95%) of the Ptolemaida V load be considered acceptable, the desired outcome can be achieved by using even more combinations of RES power and storage capacity.



---

[3] Stefanakos I. (2013). "Investigating the construction potential of new pumped hydro energy storage stations in Greece". NTUA: Research Project 62/2423 (Construction potential of pumped hydro energy storage projects in Mainland Greece).

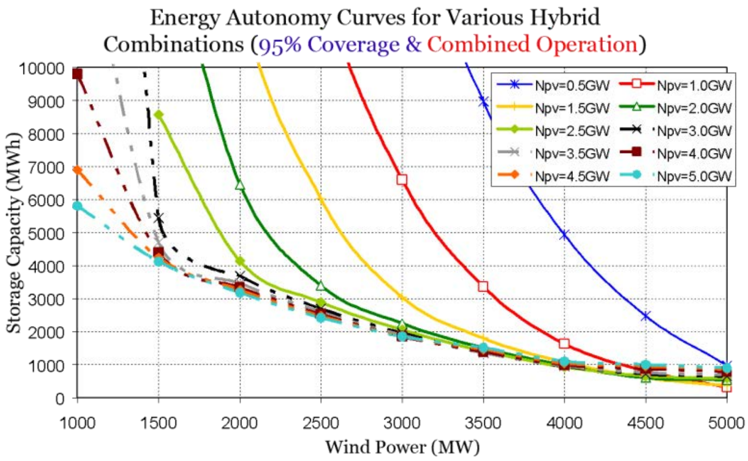


Figure 2. Energy autonomous hybrid combinations that can achieve 100% and 95% coverage of the Ptolemaida V base load, assuming a 10 GWh upper limit in capacity storage

Most important of all, <u>many of these solutions prove to be economically more favourable compared to Ptolemaida V</u>, as their levelised cost is considerably lower than that of the new lignite plant (Figure 3). These solutions, for different application scenarios, are presented in detail in Table 1.

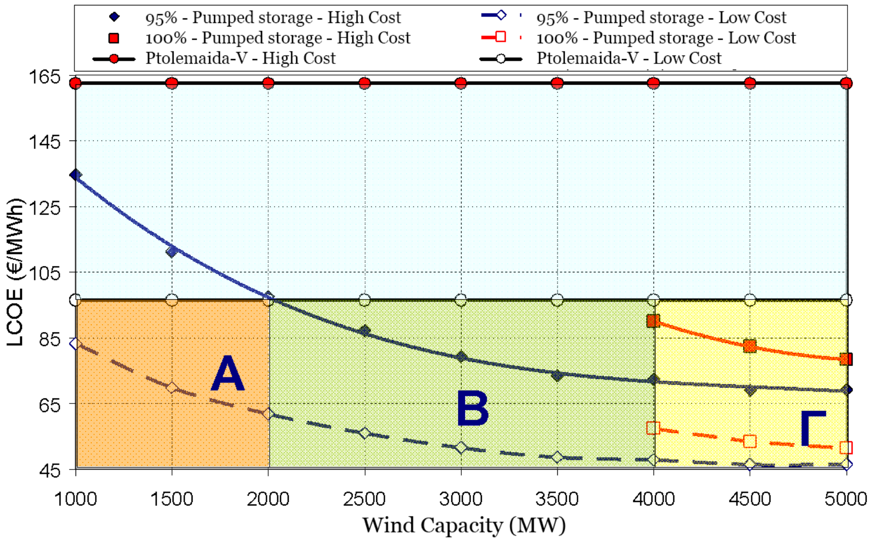


Figure 3. Levelised production cost of energy autonomous hybrid combinations - Achieving 100% (a) and 95% (b) coverage of the base load, assuming a ≤10 GWh storage capacity

Table 1: Hybrid combinations that are economically competitive to Ptolemaida V (minimum cost of Ptolemaida V: 96.47 €/MWh)

Wind power (MW)	**PV power (MW)**	**Storage capacity (MWh)**	**LCOE (€/MWh) (high cost)**	**LCOE (€/MWh) (low cost)**
100% coverage of Ptolemaida V load				
4,000	2,500	10,000	90.06	57.43
4,500	1,500	9,000	82.35	53.47
5,000	1,000	9,500	78.44	51.42
95% coverage of Ptolemaida V load				
2,000	2,000	6,460	97.50	83.30
2,500	1,500	6,030	87.21	69.86
3,000	1,000	6,600	79.27	61.88
3,500	500	8,970	73.48	56.01
4,000	500	4,930	72.43	51.62
4,500	0	9,150	69.08	48.71
5,000	0	5,210	69.25	47.90

It is important to stress that the assumptions made for calculating the results all but favour the solution of hybrid stations. For example, the assumption of high system minimum loads (4 GW) increases the levelised cost of energy of hybrid solutions, while the rather ambitious capacity factor assumed for Ptolemaida V is larger than the one included in the design specifications of the unit (80%, according to the Environmental Impact Assessment), which results in lower production costs for the proposed lignite plant. Finally, the maximum storage capacity available in the pumped hydro energy storage units was taken to be equal to only 25% of the actual maximum available, in order to avoid hindering the current operation of the reservoirs (autonomous HP, irrigation, flood-prevention), while the efficiency of the pumped hydro energy storage units was also assumed to be particularly low (63.75%).

The results show that the conversion of existing pairs of PPC hydroelectric power plants to pumped hydro energy storage units, and their use for storing the energy produced in wind and PV stations in not only **technically feasible, but also more favourable in economic terms compared to the performance of Ptolemaida V**.

Small-scale solutions

As the actual hours of operation of Ptolemaida V drop, so does the economic performance of the unit, as was already demonstrated in a previous study by WWF Greece[1]. The reduced demand that Ptolemaida V will be asked to meet beyond 2020 is the result not only of the expected growth of large-scale RES, but also of the recent technological developments in the photovoltaic and battery sectors. These developments can turn current household consumers of electricity to prosumers (prosumers).

As part of the study, an economic assessment was performed on the implementation of the net metering mechanism that was recently voted in Greece (scenario "Ministerial Decree -MD") in order to promote the use of photovoltaics. The assessment showed that there is great potential in the development of small-scale systems in order to meet household energy demands, partly due to the country's high levels of insolation. Should the net metering mechanism improve on the basis of the change suggested herein ('Alternative Plan' scenario) in the future, this potential could become even greater. The results of the analysis are given in Figure 4.

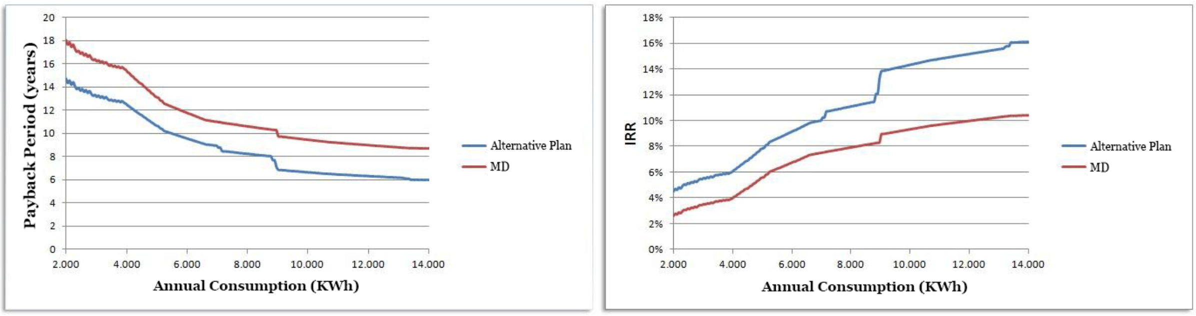


Figure 4. Payback period (left) and IRR (right) as a function of the annual energy consumption for the 'MD' and 'Alternative Plan' scenarios

The return of investments on residential, stand-alone photovoltaic systems using ion-lithium batteries was also examined. The cost of such systems, based on the predictions of market analysts, is expected to drop sharply over the next 10-15 years, due to drastic reductions in battery costs. The realisation of the aforementioned prediction, combined with the drop in PV installation costs, the expected increase in domestic power consumption and the increase in energy prices, could render autonomous systems directly competitive with centralised electricity production in Greece (Table 2).

Table 2: Payback time and internal rate of return (IRR) of autonomous systems for different scenarios (9,045 KWh annual consumption)

Battery unit cost ($/KWh)	'MD' Scenario		'Alternative Plan' Scenario	
	Payback period (years)	IRR	Payback period (years)	IRR
500	>25	-2.70%	>25	-1.20%
400	>25	-1.97%	>25	-0.40%
300	>25	-1.13%	23.32	0.54%
200	22.94	0.67%	18.30	2.56%
100	15.61	4.00%	12.26	6.44%

Apart from fully autonomous PV systems using batteries, there is also the option of storing energy in the batteries of electric vehicles. The growth of electric vehicles in Greece can contribute, under certain circumstances, to independence from the use and import of fossil fuels, to peak power smoothing and to the further development of RES, and eventually reduce the electricity demand that Ptolemaida V will be asked to cover between 2020-2050.

It is, therefore, concluded that the developments in the field of small-scale PV, either employing net metering, stand-alone systems with batteries, or a combination of both, can lead the way in the forthcoming, drastic transformation of the existing model of electricity production: from centralized, huge, fossil-fuel power plants like Ptolemaida V, towards decentralized, stand-alone systems and ultimately a gradual independence from grid-produced electricity.

Conclusions - proposals

Lignite dependency is not the only option for Greece. This study proposes and provides evidence to support specific alternative solutions that eliminate the need for constructing the Ptolemaida V plant. These solutions are technically feasible and at the same time outmatch the planned unit both economically and environmentally.

In this context, WWF Greece is calling for the Greek state to:

- Re-examine the economic sustainability of the new unit and evaluate the equivalent alternative solutions proposed.
- Establish the appropriate institutional framework regarding pumped hydro energy storage.
- Improve the regulatory framework regarding net metering and, as a next step, design a policy mechanism that will promote the development of small-scale, stand-alone RES systems.
- Provide the necessary infrastructure for the growth of the electric vehicle market in Greece.
- Plan a new business model for the PPC, built around profitable sectors that will maximise the benefits of the business, the customers and the environment.
- Set out a thorough national energy plan that will take into account the emerging developments in the clean energy sector at an international level and will delineate the development over time of the participation of each power generating technology in the country's energy mix up to 2030 and 2050.

1. INTRODUCTION

1.1. Recent developments and aim of the study

On March 29th 2013, the General Assembly of the Public Power Corporation S.A. (PPC) shareholders approved the agreement for the construction of the new lignite plant Ptolemaida V, which is expected to come into operation in 2020. It will be the first lignite plant in Greece since 2002, when the 450 MW Meliti plant in Florina came into operation.

Meanwhile, over the past 18 months, there have been dramatic changes in the international climate and energy policies that are expected to also have a major impact on the economic sustainability of lignite plants in Greece. The decision of the USA to set a ceiling on the CO_2 emissions of the country's existing coal plants[4] was particularly important, given the fact that up to recently it had shown a negative attitude in international negotiations on climate change. At the same time, the USA are leading an international campaign for limiting the funding of new coal plants, which has been met with great success as many countries are now adopting similar commitments. Perhaps the most important contribution in this direction was the agreement last November between USA and China[5], the biggest polluter worldwide, regarding the measures for reducing CO_2 emissions for both countries. On top of these changes in the political scene, the European Council decided in October 2014[6] to set a target for reducing CO_2 emissions in Europe by at least 40% by 2030.

The financial services sector couldn't have been left unaffected by these developments at a political level. One after another, financial institutions have placed strict constraints on emissions limits as a precondition for funding the construction of new coal plants, which, in practice, mean the discarding of lignite. It is important to note that the initial plans of PPC[7] regarding the contribution of the European Investment Bank (EIB) in financing the new Ptolemaida V lignite plant were cancelled[8], following an EIB decision to set a 550 Kg CO_2/MWh limit on the emissions, which is only half of that expected to be emitted by Ptolemaida V. But even the German development bank KfW, which is the only one supporting the construction of Ptolemaida V, has lately been receiving increasing pressure[9] from members of the German government to change its funding policy regarding new coal plants in other countries.

In addition, one should take into account a less known, but nevertheless important process taking place in the context of the European policy for reducing the emissions of coal plants: the so-called 'Sevilla process'[10], according to which the Best Available Techniques (BAT) and their corresponding sulfur dioxide, nitrous oxide and particulate matter limits are reviewed on a regular basis. According to European legislation, BAT form the basis for defining the licensing terms of new lignite plants. The ongoing review will be completed in 2015 and will come into force by 2019. Tighter limits will also mean additional expenses for installing more efficient anti-pollution technology, which will have an economic impact on Ptolemaida V, since its specification limits lie right below the upper NO_x, SO_2 and particulate matter limits of the BAT under review.

---

[4] Mantzaris, Nikos. (2014, 6 June). "Emissions reduction in the USA: A small step for America, a huge step for global climate policy?". WWF blog. http://www.wwf.gr/blog/post/2014-06-06-12-56-03

[5] Landler, Mark (2014, 11 November). "U.S. and China Reach Climate Accord After Months of Talks", The New York Times. http://www.nytimes.com/2014/11/12/world/asia/china-us-xi-obama-apec.html?smid=fb-share&_r=1

[6] Conclusions of the European Council 23-24 October 2014, http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf

[7] Zervos, Arthuros. (2012, 21 March). Briefing of the Greek Parliament's Ongoing Committee for Production and Commerce by the PPC's President and CE, see video (36:05')

[8] WWF Greece press release. (2014, 9 January). "The European Investment bank shuts the door to Ptolemaida 5", http://www.wwf.gr/news/907-5

[9] Chambers, Madeline. (2014, 18 September). "Germany to cut support for overseas coal plants", Reuters. http://www.reuters.com/article/2014/09/18/germany-coal-idUSL6N0RJ2XP20140918

[10] European Commission. More information on the European IPPC Bureau (EIPPCB). http://eippcb.jrc.ec.europa.eu/about/more_information.html

Another main factor is the evolution of carbon prices as part of the EU Emissions Trading System (EU ETS). Even according to the modest estimates that formed the basis of the 2012 Greek Energy Roadmap to 2050, the allowance cost is expected to rise between 2020-2050, reaching up to €310 per ton by 2050, and, according to many estimates, to €30 per ton by 2030. The emission allowance cost is expected to increase even more as a result of the increase in the annual reduction factor in the 'cap' (from 1.74% to 2.2%) on the maximum number of emission allowances beyond 2021, by implementing the Market Stability Reserve Mechanism that was proposed by the European Commission,[11] as part of the 2030 plan for climate and energy. According to various implementation scenarios of this mechanism, the emissions allowance cost is expected to exceed €30 per ton even before 2030, maintaining an increasing trend for the years to follow[12]. Such a development alone can result in Ptolemaida V becoming economically unsustainable, given that there are estimates by the PPC[13] itself -presented in a recent workshop regarding the post-lignite era – which predict that natural gas will become more preferable than lignite, economically speaking, once carbon costs have exceeded €30 per ton.

Energy giants such as E.On[14], Germany's largest power-producer, also seem to grasp these ongoing global changes, as the company recently split into two, abandoning coal and natural gas and turning towards Renewable Energy Sources (RES) and energy services. A year earlier, RWE[15], the second largest company in Germany, announced that its revenues had dropped due to an increase in decentralized electricity production using RES, and that it had decided to change its business model by turning to RES, too. EnBW[16], the fourth largest company in Germany, announced a similar shift to RES, networks and decentralized energy production by 2014. Portuguese company EDP[17] is another proven example of adapting to the new circumstances, as it almost tripled its RES electricity production between 2005-2013, which meant that by the end of 2013 it was producing 71% of its power from RES.

For a country in a devastating economic situation such as Greece's, such changes in the energy scene are of even greater, almost multifold, importance. The 660 MW Ptolemaida V plant will cost a total of €1.4b, half of which will be provided by KfW in the form of a bond loan. The other half, however, will result from own funds of the already over-indebted PPC, which will need to spend an additional large amount on upgrading existing lignite plants from 2015 onwards – and for the following 4-5 years – in order to comply with European legislation, a need that is now acknowledged publicly even by staff members of PPC[18].

The example of the TES6 unit in Sostanj, Slovenia, which is of similar size (600 MW) but more efficient compared to Ptolemaida V (46% vs 41,5%), should be taken very seriously into account, before it is too late: €70-80m annual losses that will burden Slovenian citizens, 225 jobs instead

---

[11] European Commission. (2014, 22 January). Proposal for a DECISION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/EC.
[12] Carbon Market Watch. (2014, July). What's needed to fix the EU's carbon market. Recommendations for the Market Stability Reserve and future ETS reform proposals. http://carbonmarketwatch.org/wp-content/uploads/2014/07/ETS-POLICY-BRIEF-JULY-2014_final_1.pdf
[13] Leonardos, Marios, PPC Planning and Mines Efficiency Manager. (2014, 6 December). "PPC strategy and planning for the role of lignite in the Greek Power System". Presentation at the Green Institute Workshop 'The transition of Greece and particularly Wester Macedonia towards a post-lignite era – challenges and opportunities". http://goo.gl/8Xo58g
[14] Stephen, Lacey. (2014, 1 December). "Germany's Biggest Utility, E.ON, Is Divesting Fully From Centralized Power Plants". NC Warn. http://www.ncwarn.org/2014/12/germanys-biggest-utility-e-on-is-divesting-fullyfrom-centralized-power-plants-green-tech-media/
[15] Beckman, Karel. (2013, 21 October). Energypost.eu. "Exclusive: RWE sheds old business model, embraces transition". http://www.energypost.eu/exclusive-rwe-sheds-old-business-model-embraces-energy-transition/
[16] EnBW, Press Release. (2014, 7 March). "FY 2013: Strategic reorientation launched, efficiency programme successfully accelerated", https://www.enbw.com/company/press/press-releases/press-release-details_64064.html
[17] EDP, Renewable Energies, http://www.edp.pt/en/sustentabilidade/ambiente/energiasrenovaveis/Pages/energias_renovaveis.aspx
[18] Energypress. (2015, 27 January)."Petrakos: First step, the end of Small PPC" http://www.energypress.gr/news/Petrakos-:-Praxh-prwth-to-telos-ths-Mikrhs-DEH

of the several times more that were promised, and a total €1.4b of installation costs compared to €0.6b that was initially budgeted[19].

According to a previous study by WWF Greece[20], Ptolemaida V is not better placed than TES6. The operating hours of both Ptolemaida V and Meliti II, the second lignite plant being planned, are expected to drop by up to 35% by 2050, due to the expected increase in the share of RES in the country's power mix. The economic viability of the two lignite plants is therefore under serious doubt. Particularly Ptolemaida V is expected to even develop a negative internal rate of return (IRR) of the initial investment, down to -5.4%. In practice, that means that for every €100 that has been invested, PPC will receive €94.6.

Therefore, on the basis of the aforementioned developments, it becomes essential to examine alternatives to Ptolemaida V. The aim of the current study is to research and perform an economic assessment of the alternative solutions to the construction of Ptolemaida V, which are based on the use of RES combined with central or decentralized energy storage systems.

1.2. Structure of the report

In Chapter 2, the Greek Electric Power System is presented and an analysis of the operational characteristics of various power plants is performed (lignite, hydro power, wind and PV), which will later be used in the calculations.

Chapter 3 presents the main characteristics of the most important RES technologies and performs a comparative economic evaluation both between them and against conventional power plants (Ptolemaida V and natural gas power plants).

Chapter 4 includes a short description of energy storage technologies that can be used alongside variable RES (wind and PV), in order to deal with the intermittent nature of the latter. Emphasis is given on pumped hydro energy storage, the most mature storage technology nowadays.

Chapter 5 offers a detailed presentation of the main alternative proposal to the construction of Ptolemaida V, which consists in combining variable RES (wind and PV) and pumped hydro energy storage units, with the aim of covering the base load that the new lignite plant is planned to meet. It also includes an energy analysis of the hybrid solutions and their economic assessment compared to Ptolemaida V.

Chapter 6 examines the small-scale solutions that are capable of significantly reducing the power demand of central, conventional power plants such as Ptolemaida V. More specifically, it includes an economic assessment of small-scale, household PV systems employing a stand-alone electricity production scheme using net metering, as well as an assessment of fully autonomous systems that consist of small-scale PV combined with batteries.

Finally, Chapter 7 deals with the growth prospect of electric vehicles in Greece, as it can complement the development of small-scale household PV, offering, on the one hand, the option of energy storage, and, on the other hand, the additional potential for using solar energy indirectly, in the transport sector.

[19] Bankwatch, Press Release. (2014, 2 December). "Sostanj lignite plant: A mistake not to be repeated", http://bankwatch.org/news-media/for-journalists/press-releases/sostanj-lignite-plant-mistake-not-be-repeated
[20] WWF Greece. (2013, 26 June). "Ptolemaida 5 and Meliti 2, Economic viability report of the new lignite plants"

2. THE GREEK ELECTRIC POWER SYSTEM

2.1 Description of the electric power system

The Greek Electric Power System is heavily based on the exploitation of domestic lignite reserves[21] and natural gas imports, along with oil imports for the operation of the autonomous power stations of the non-interconnected island system[22]. As far as the installed capacity of the mainland is concerned (National Interconnected System – NIS)[23], today there are 10.06 GW of net power in operation, of which 4,456 MW correspond to lignite power plants and 698 MW to oil-fired plants. In addition, there are 1,684 MW of power produced in oil plants[24] located on non-interconnected islands. Decisive to the operation of the system is the contribution of approximately 3 GW of hydroelectric power (HP) produced by a total of 14 plants and 39 units, mainly peaker plants. These include two pumped hydro energy storage (PHES) units: the Thisavros station, part of the Nestos complex in the Drama prefecture and the Sfikia unit, part of the Aliakmonas complex in the Imathia prefecture, totaling a power of approximately 700 MW.

The power generated by RES, and wind and PV systems in particular, has increased considerably over the past years (Figure 2.1). The installed capacity of wind systems has increased by 46% between 2010-2013, from 1,298 MW in 2010 to 1,810 MW in December 2013[25,26]. The increase in PV installed capacity has been much more significant, over 150% per annum between 2010-2012. It exceeded 2,578 MW[27] by the end of 2013, 374 MW of which are from small-scale systems (up to 10kW) on approximately 41,217 rooftops. Small hydropower plants (SHPP) have shown an increase of 23 MW, reaching a total of 220 MW, while biomass plants - mainly consisting of sanitary landfill gas utilization units - reached 46 MW in 2013.

---

[21] Kaldellis, J.K., Zafirakis, D., Kondili, E. (2009, March). "Contribution of lignite in the Greek electricity generation: Review and future prospects". Fuel, Volume 88, Issue 3, Pages 475-489

[22] Kaldellis, J.K., Zafirakis, D. (2007, September). "Present situation and future prospects of electricity generation in Aegean Archipelago islands". Energy Policy, Volume 35, Issue 9, Pages 4623-4639

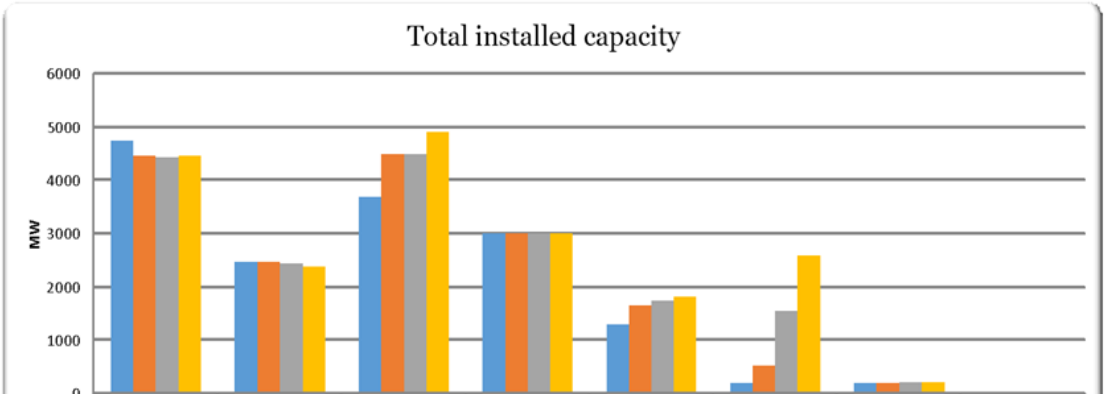
[23] Independent Power Transmission Operator (IPTO). (2014, February). Ten-year Development Program of the Transportational System 2015-2024 - Preliminary Stage. http://www.admie.gr/uploads/media/DPA_2015-2024_Prokatarktiko_Schedio_Kyrio_teychos.pdf

[24] LAGIE SA (2014, December). DAS Settlement System Monthly Bulletin, http://www.lagie.gr/fileadmin/groups/EDRETH/DAS_Monthly_Reports/201412_DAS_Monthly_Report.pdf

[25] LAGIE SA,. (2014, January). Special RES & CHP Account Monthly Bulletin, http://www.lagie.gr/fileadmin/groups/EDSHE/MiniaiaDeltiaEL/2014_01_Miniaio_Deltio_EL_APESITHYA_v2.pdf

[26] HEDNO. (2013, December). Information Bulletin - Production in Non-Interconnected Islands. http://goo.gl/IccSdx

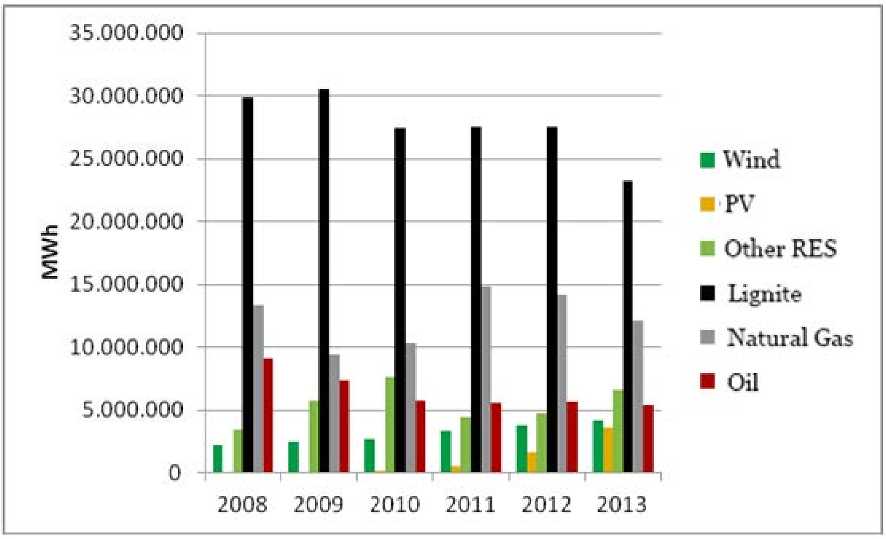
[27] Hellenic Association of Photovoltaic Companies (HELAPCO), (2014, June). "PV market statistics for 2013". http://helapco.gr/wp-content/uploads/pv-stats_greece_2013_June14.pdf



	Lignite	Oil	Natural Gas	HP	Wind	PV	SHPP	Biomass
2010	4746	2474	3679	3018	1298	191	197	41
2011	4456	2474	4487	3018	1640	522	206	45
2012	4448	2456	4479	3018	1753	1556	213	45
2013	4456	2382	4906	3018	1809	2578	220	46

Figure 2.1. Installed power data (Sources: LAGIE, IPTO, HEDNO)

Figure 2.2 shows the development of Greece's energy mix between 2008-2013, regarding both the interconnected and the non-interconnected systems. The contribution of lignite exceeded 50% (2009) with approximately 30.5 TWh, but dropped significantly in 2013 to about 41% (46% in the interconnected system) with 23 TWh. The contribution of natural gas varied significantly over the past years, reaching 15 TWh in 2011 (a share of 25.84%) and dropping to 12.15 TWh in 2013 (21.67% share). The contribution of oil is decreasing mainly due to it being abandoned in the interconnected system but also as a result of the steady, yet slow, increase in RES growth in non-interconnected islands (an increase in RES contribution from 10.37% in 2008 to 18.41% in 2013). In 2013, the share of RES in the country's energy mix reached its peak, surpassing natural gas at a rate of 26%, a result that was largely due to the increased production of the country's large HP plants, contributing approximately 11%.



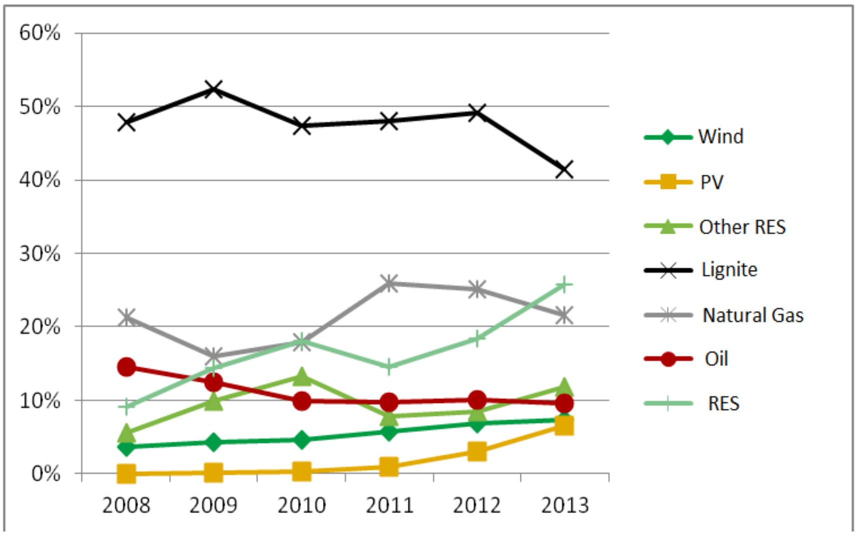


Figure 2.2. Energy mix development over time in the interconnected and non-interconnected Greek power systems (based on LAGIE, IPTO, HEDNO data)

It should be noted that this increase in RES share would have been much larger had it not been for numerous laws and regulations that, from 2012 onwards, have either reduced the guaranteed RES rates or imposed retroactive reductions to them. It is interesting to note that throughout 2014 there were only 86 MW of wind and 6 MW of PV installed in the interconnected transmission network[28]. As a result of this policy, which brought the development of RES to a halt, Greece is still far from meeting its national commitments as far as RES share is concerned.

More specifically, as part of implementing the 2009/28/EC Directive[29], Greece is obliged to achieve an 18% share of RES in gross final energy consumption. In addition, law 3851/2010[30] sets out even more ambitious national goals regarding RES for 2020:

- 20% contribution of RES-produced energy to the gross final energy consumption.
- 40% contribution of RES-produced electricity to the gross electricity consumption.
- 20% contribution RES-produced energy to the final heating and cooling energy consumption.
- 10% contribution of the RES-produced electricity to the gross transport electricity consumption.

[28] LAGIE SA. (2014, December). Special RES & CHP Account Monthly Bulletin, http://www.lagie.gr/fileadmin/groups/EDSHE/MiniaiaDeltiaEL/2014_12_Miniaio_Deltio_EL_APESITHYA.pdf

[29] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC http://www.ypeka.gr/LinkClick.aspx?fileticket=flZekDiD%2Brg%3D&tabid=446&language=el-GR

[30] Law 3851/2010. (Greek Government Gazzette A 85/04.062010). "Acceleration of Renewable Energy Sources growth to mitigate climate change and other clauses within the jurisdiction of the Ministry of Environment, Energy and Climate Change". http://www.ypeka.gr/LinkClick.aspx?fileticket=pnhppGnURds%3D

These targets were made more specific for each RES technology in the 19598/2010 Ministerial Decree, both for 2014 and 2020, (Table 2.1).

Table 2.1. Targeted[31], under development[23] and operational RES power[32,33].

RES type	2014 Target	2020 Target	Non binding connection bid (10/2013)	Binding connection bid (10/2013)	In operation (9/2014)
Wind	4,000	7,500	13,845	4,393	1,903
PV	1,500	2,200	1,263	1,471	2,215
PV roofs	-	-	-	-	375
Large HP	3,400	4,300	-	-	3,018
Small HP	300	350	288	78	220
Biomass/Bio gas	200	350	198	0	46
Solar	120	250	11	2	0

According to the table, Greece is well behind in terms of meeting the RES development targets - and especially those related to wind power. However, it's still feasible to achieve them, taking into account the interest in investment which depicted in the capacity included in the binding connection bid column. It should be noted that the increase in RES penetration is one of the main targets of European energy policy even beyond 2020, as in the recent decision of the European Council in 2014, regarding the new climate and energy framework for the next decade[34], an 'at least' 27% RES share in the final consumption was agreed by 2030. Despite the public statements of the Greek Minister of Environment, Energy and Climate Change (MEECC) regarding a 30% RES share in the final energy consumption by 2030[35], there has been no specific proposal submitted by the MEECC as part of the already delayed national energy plan. Thus the only commitment of Greece in force is that of 2020. From the above, it becomes clear that reversing the negative political climate of the past decades regarding RES can place the country on course to achieving both the national commitments for 2020 and the ambitious targets of 2030.

2.2. Analysis on meeting electricity demands

For the purpose of the current study, it is necessary to provide a detailed analysis of the contribution of various energy sources to total electricity consumption. Figure 2.3 presents the hourly values for meeting electricity demand in the National Interconnected System (NIS), for a typical winter and summer week respectively. One can clearly note the peaking behaviour of large-scale hydro, the 'intermittent' nature of RES, the operation of natural gas plants (mainly of intermediate load), and that of base-load lignite plants.

---

31 'Decision on the targeted share of installed power and its distribution over time regarding various RES technologies'. (2010, 11 October). Greek Government Gazzette no. 1,630.
32 LAGIE SA. (2014, October). Special RES & CHP Account Monthly Bulletin, http://www.lagie.gr/fileadmin/groups/EDSHE/MiniaiaDeltiaEL/2014_10_Miniaio_Deltio_EL_APESITHYA.pdf
33 HEDNO. (2014, September). Information Bulletin - Production in Non-Interconnected Islands http://goo.gl/uITwoO
34 Conclusions adopted by the European Council regarding the 2030 Climate and Energy Policy Framework, 23-24 October 2014. (2014, 24 October) http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf
35 Hellenic Wind Energy Association (HWEA). (2014, 9 April). "Great Expectations! RES targets: 2020 to 2030. The development of wind energy and RES in Greece and Europe". http://goo.gl/DHbX12

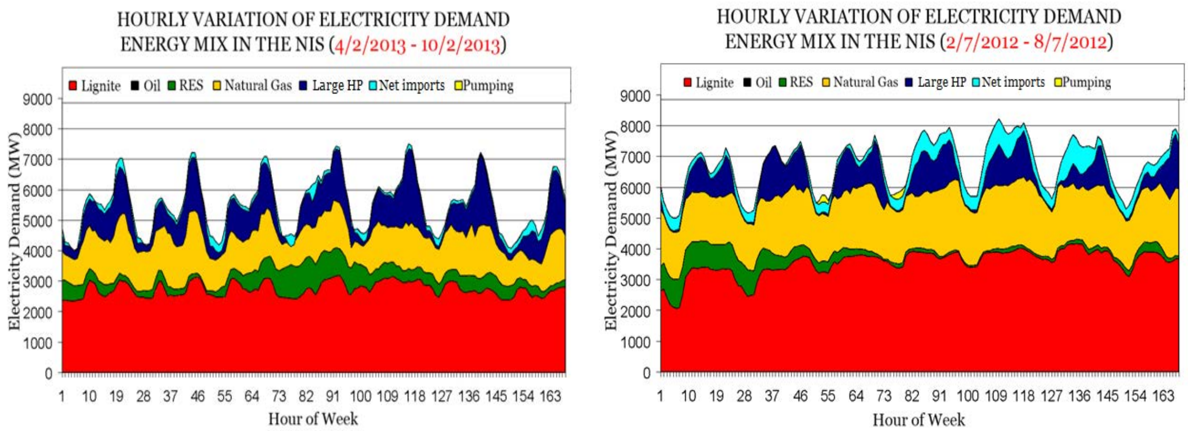


Figure 2.3. Hourly electricity demand mix of the NIS for a typical winter (a) and summer (b) week[36]

The sharp increase in hourly demand during summer and winter months can be seen in Figure 2.4 (2012 data). It is interesting to note that there is a 9.8 GW annual system peak, when the total conventional available power capacity is 13 GW (including large hydro). In addition, as a result of the financial crisis, the total electricity demand of the NIS has dropped significantly over the past years by approximately 6%, from 56.3 TWh in 2008 to 52.3 TWh in 2012. Nevertheless, and according to the validated electricity demand scenarios of the Independent Power Transmission Operator (IPTO), the total demand is expected to increase once again (Figure 2.4b), reaching 2008 levels by 2019.

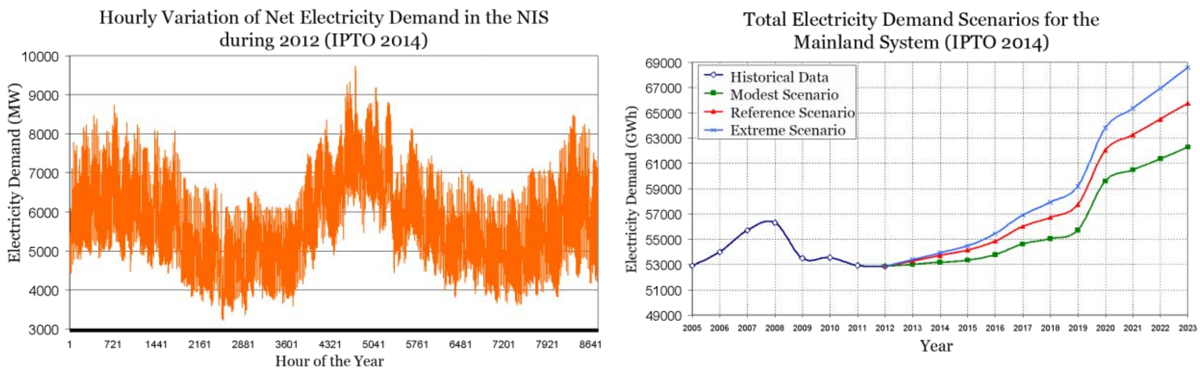


Figure 2.4. Hourly electricity demand 2012 (a)[36] *and prediction of long-term demand (b)*[37]

2.2.1 Lignite plants

Figure 2.5 shows the hourly load curves for typical NIS units, for a typical day of the 4-year stretch between 2009-2012 (Figure 2.5a). As can be noted, the hourly capacity factor of the units (per net power) varies according to the electricity demand, and in most cases -even during periods of low consumption- stays above 60%, with the lower limit being determined by the minimum load of each unit. In addition, Figure 2.5b shows the long-term capacity factor (2009-2012) for all the lignite plants, which varies between ~60% and ~80% (per net power), the higher value being that of the Agios Dimitrios V unit (~82%).

---

[36] Independent Power Transmission Operator (IPTO). 2014. "Operation and Data. Unit Production Loads and System Loads". http://www.admie.gr/leitoyrgia-dedomena/ekkatharisi/fortisi-monadon-paragogis-kai-fortia-systimatos/

[37] IPTO. (2014, March). Ten-year Development Program of the Transportational System 2014-2023. http://www.admie.gr/to-systima-metaforas/anaptyxi-systimatos/meleti-anaptyxis-systimatos-metaforas/archeio/document/94667/doccat/detail/Document/

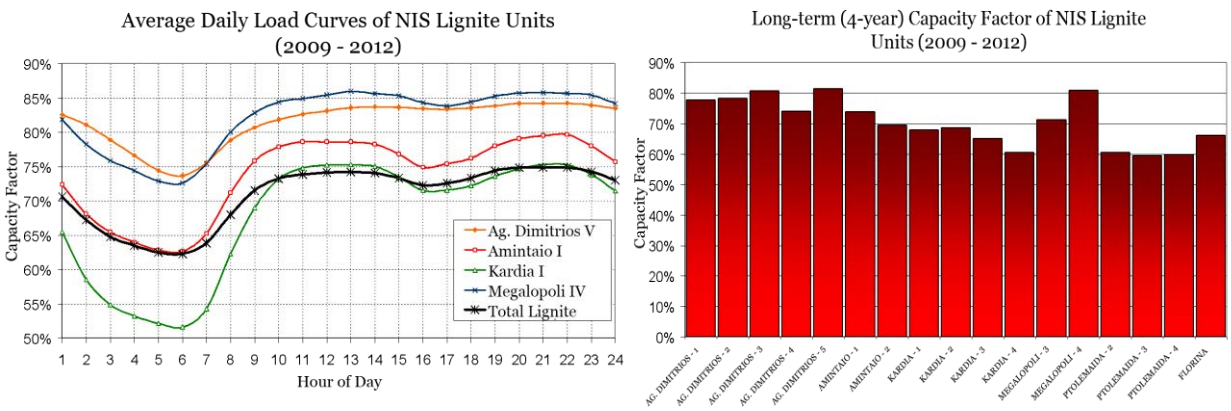


Figure 2.5. Fluctuation profile of the average daily capacity factor of representative lignite plants (a) and long-term capacity factor of NIS units (b) (2009-2012)[36]

2.2.2 Variable RES

Using hourly net energy production data between 2009-2012[36] and for all the energy sources contributing to the NIS at unit level, Figure 2.6 and Figure 2.7 present detailed results regarding the energy production (hourly capacity factor) of variable RES (wind and PV). More specifically, Figure 2.6 shows the hourly values of the capacity factor of NIS wind farms between 2009-2012, the average value being approximately 22%. The same figure shows an estimate of the hourly capacity factor, for a typical day of the year. According to the results, there is a gradual reduction over the years in the capacity factor of wind production around midday. This illustrates – given the spread of wind farms to almost the entire Greek territory – the reduced complementarity of wind power capacity, as a result of its varying characteristics depending on the area and the unequal distribution of installed capacity per region. Also evident is a trend in the reduction of the wind capacity factor during summer. These findings are particularly important, as they reveal a high degree of complementarity between wind and PV production.

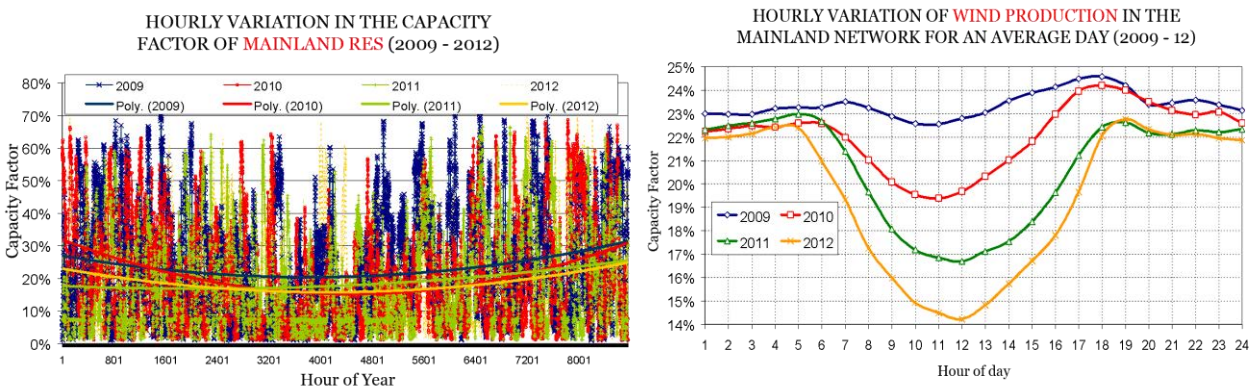


Figure 2.6. Long-term (a) and average daily (b) hourly profiles of the capacity factor for wind farms of the mainland network[36] (poly: trendline)

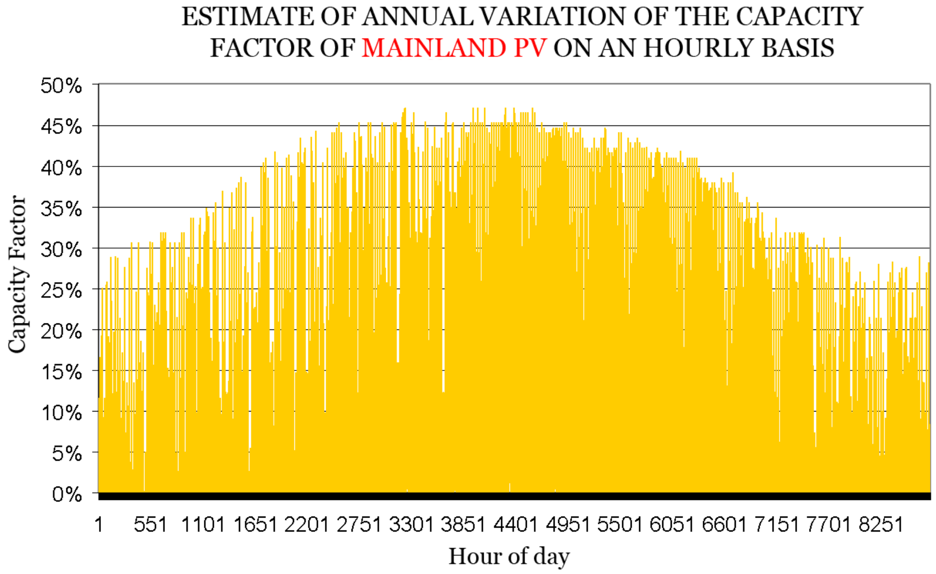


Figure 2.7. Average, longterm hourly profile of the capacity factor for PV plants of NIS[36]

2.2.3 Hydroelectric plants

Unlike the variations in the capacity factor of small hydro plants (Figure 2.8), which depend on the seasonal fluctuations of rainfalls, the operation of large hydro plants does not necessarily follow that pattern, due to their ability to regulate their operation through the use of dams. This increases the likelihood of a high capacity factor during summer as well, with the aim of allowing large hydro plants to contribute towards meeting the increased load demand, as can be seen in Figure 2.9 and Figure 2.10. The latter present the annual – for a typical year – variation of the daily and hourly capacity factor, respectively, for all the large hydro plants of the NIS (based on data between 2009-2012).

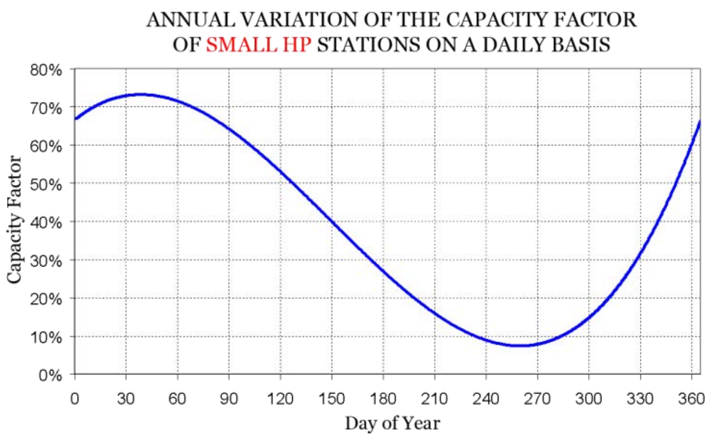


Figure 2.8. Typical distribution of the the capacity factor of small hydro plants[36]

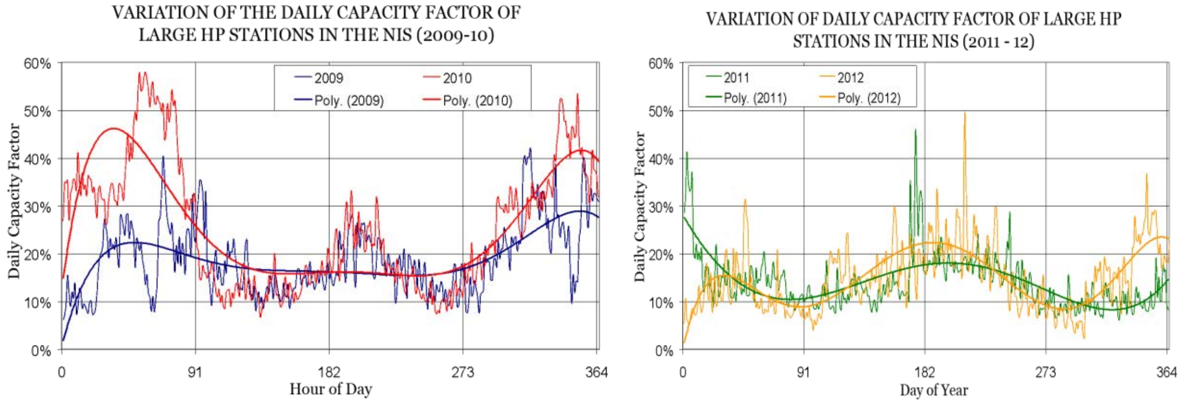


Figure 2.9. Annual variation of the capacity factor for large hydro plants of the NIS[36] (poly: trendline)

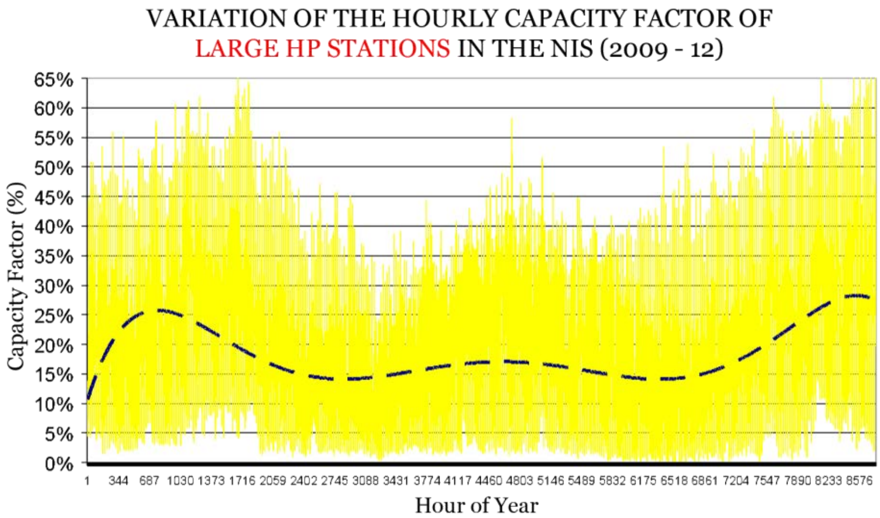


Figure 2.10. Annual variation of the hourly capacity factor for large hydro plants of the NIS36

At the same time, and according to Figure 2.11a, which shows the cumulative probability curves per hour for all large hydro plants, there is an increased probability of high loads during peak hours (12.00-14.00 and 20.00-22.00). Besides, the peaking nature of large hydro also becomes evident by the annual load of the plants (Figure 2.11b). By way of illustration, the load of large hydro plants stays below 1 GW (approximately 33% of the installed power) for 80% of the time, whereas the equivalent value of lignite plants can even exceed 80% (see Figure 2.5b).

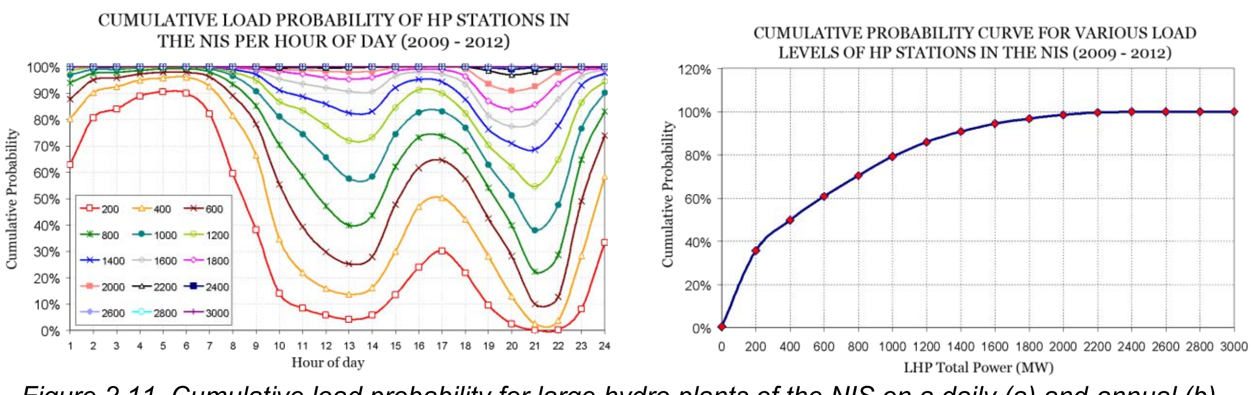


Figure 2.11. Cumulative load probability for large hydro plants of the NIS on a daily (a) and annual (b) basis[36].

It is also worth noting the discrepancy between winter and summer hourly load levels (Figure 2.12), which is in line with the different demands for electricity during peak hours (fairly balanced throughout the day in summer and clearly elevated during night peaks in winter).

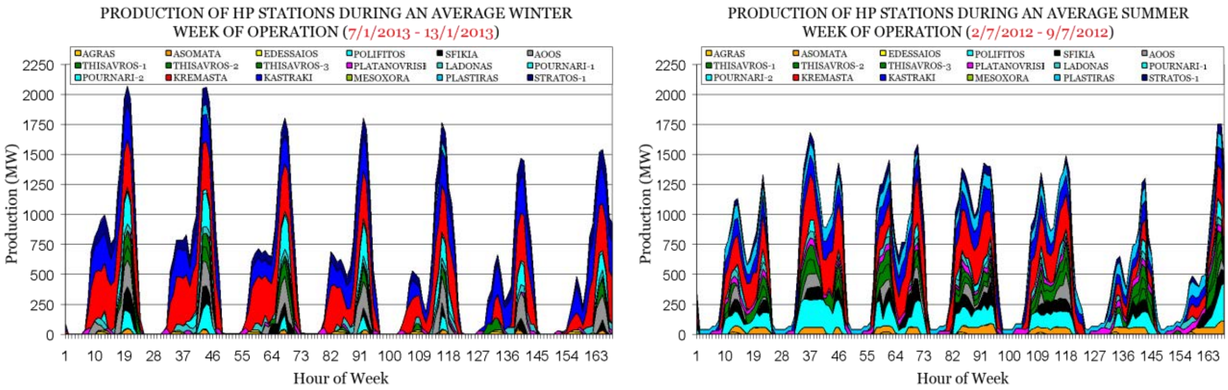


Figure 2.12. Examples of the operation of large hydro plants in the NIS for a typical winter (a) and summer (b) week[36]

2.2.4. Pumped Hydro Energy Storage (PHES)

Particular mention should also be made to the two existing pumped hydro energy storage units of the NIS, whose characteristics are presented in Table 2.2 Sfikia is used exclusively for electricity generation while Thisavros is also used for irrigation and flood-prevention purposes. Both units are used today mainly to support the operation of the lignite plants. They pump water during night hours (Figure 2.13), in order to take advantage of the energy surplus of the base lignite plants. In this way, on the one hand the load of the latter can be kept within the desired limits – i.e. higher than the corresponding off-peak demand and their minimum load - and on the other hand this energy (reduced due to load/unload cycle losses) can be used during peak hours on the following day.

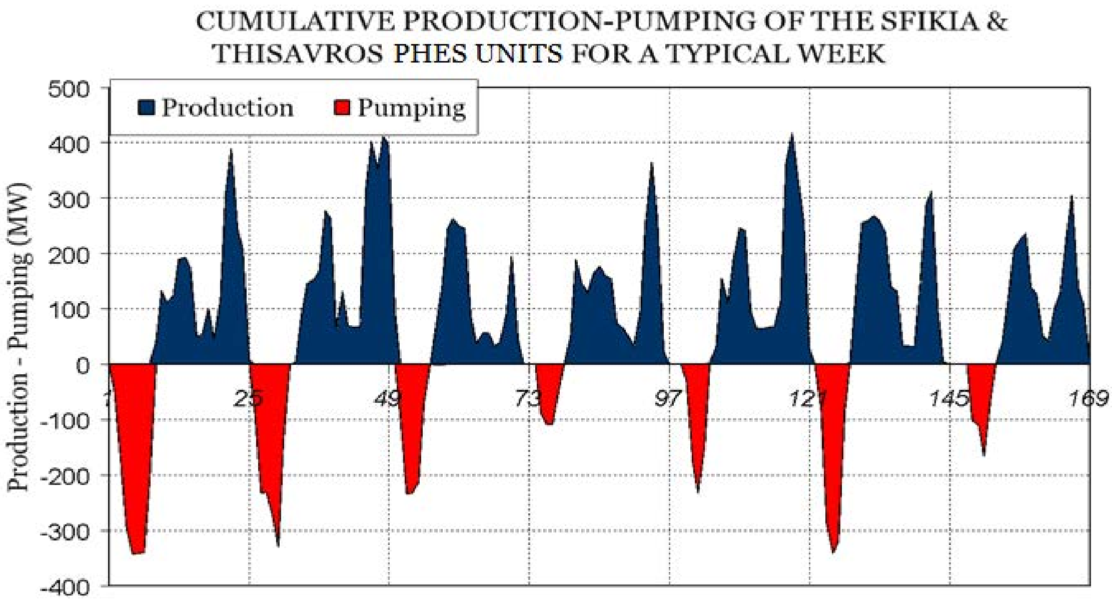


Figure 2.13. Operation of the reversible Thisavros and Sfikia hydroelectric plants for a typical week[36]

Nevertheless, and despite the fact that both units benefit from significant amounts of water flowing in from the adjacent rivers (the Thisavros reservoir is classified as of annual use while Sfikias' as weekly)[38], their operating philosophy is reminiscent more of conventional hydro plants than exclusive pumped hydro energy storage units.

Table 2.2: Characteristics of the existing pumped hydro energy storage units

Unit	**Location**	**Opening Date**	**Installed Power**	**Turbines**	**Dam**	**Capacity**
Sfikia	Imathia Prefecture	1985/86	315 MW (3x105 MW)	Reversible Francis	Sand – 82m height	18 Mm^3
Thisavros	Drama Prefecture	1998	384 MW (3x128 MW)	Reversible Francis	Rockfill – 172m height	565 Mm^3

This also explains the paradox of lower energy load demands for pumping given the corresponding energy production during a daily cycle (by omitting the water residues of the previous pumping – see Figure 2.13). This conclusion is also confirmed by the long-term operation of the units.

More specifically, and according to the cumulative data presented in Figure 2.14 for both units, there is a clear discrepancy between the energy produced (~2.1 TWh) and the energy required for pumping (0.7 TWh) throughout the 2010-2012 period, revealing the dual nature of the units, as well as the ability of the existing large hydro plants to contribute both as conventional and as energy storage units, offering flexibility to the power system.

Finally, it is important to note that, to date, the operation of the pumping units of the two plants has a low usage rate and is based on exploiting the surplus of lignite production. That helps the power smoothing of lignite plants, but at the same time contributes towards maintaining a polluting national energy mix.

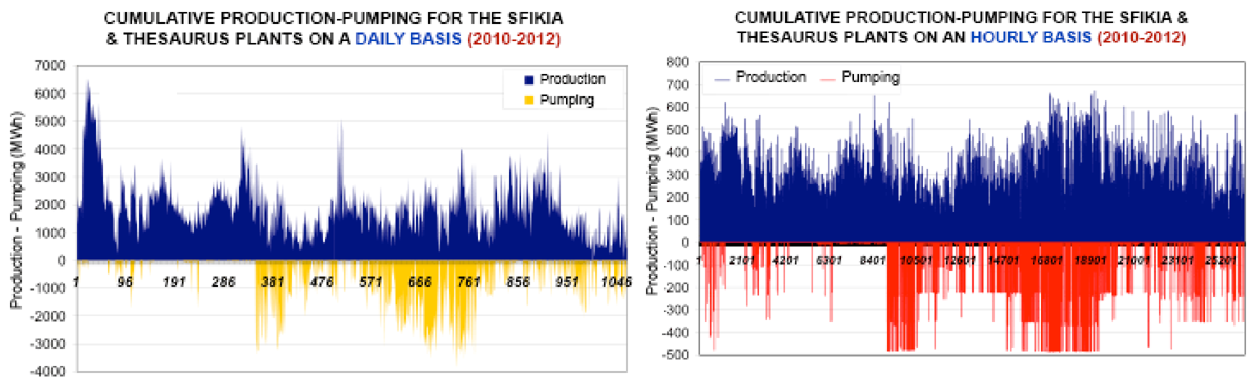


Figure 2.14. Operation of the reversible Thisavros and Sfikia hydro power plants on a daily (above) and hourly (below) basis (2010-12).

[38] Leris, Georgios. (2006, 23-26 November). "Exploitation of Hydroelectric Power Stations". Energy 2006, 'ENERGYTEC 2006' International Conference & 1st International Exhibition: Energy Types & Management, HELEXPO Palace Exhibition Center, Marousi. https://www.dei.gr/Documents/Leris_Energytec_2006.pdf

3. COMPARATIVE ANALYSIS OF THE COST OF POWER GENERATION TECHNOLOGIES

Perhaps one of the greatest misconceptions, as far as power generation is concerned, is that RES are far more expensive compared to conventional production based on fossil fuels. However, the dynamic development of RES, largely due to the positive EU and international policies against climate change, has led to an important reduction in production costs, to an extent that for some technologies, and under certain circumstances, the Levelized Cost of Energy (LCOE) is comparable or even smaller to that of conventional fossil fuel units. As RES technologies keep developing, it is useful to perform a comparative analysis of both their current and their projected Levelized Cost of Energy, compared to the production cost of the Ptolemaida V power plant. For completeness, the analysis includes both closed (CCGT) and open cycle (OCGT) conventional natural gas (NG) units.

3.1 Methodology

Given the fact that the Ptolemaida plant will come into operation in 2019-20, with an expected lifespan of at least 30 years, it was deemed appropriate to compare the Levelized Cost of Energy of the plant compared to that of the RES technologies as they develop during its operation (2020-2050).

The Levelized Cost of Energy is a widespread methodology of comparative analysis. It consists in calculating the total production cost per technology throughout its operational lifespan and converting it to Net Present Value (NPV). This results to comparable costs in €/MWh between different power generation technologies.

This methodology appears in literature with a few variations, depending on the availability of data, the aim of the study and the degree of detail of the analysis[39]. The simplified method was chosen for the current study, according to which the Levelized Cost of Energy is given by the formula:

$$LCOE = \frac{NPV(CAPEX + OPEX)}{NPV(TOTEN)}$$

where *LCOE* represents the Levelized Cost of Energy, *CAPEX* the Capital Expenditures, *OPEX* the operational and maintenance costs including fuel and CO_2 emissions costs and *TOTEN* the total energy produced throughout the life-cycle of the unit.

Despite its widespread use, the Levelized Cost of Energy methodology has certain basic flaws, the most significant being that it omits the cost for integrating the various technologies to the system. That cost results from the overall operation and maintenance of the power system and requires a comprehensive analysis in order to be calculated. More recently, attempts have been made to enrich the Levelized Cost of Energy assessment by including an estimate of system integration costs (System LCOE)[40].

It should be noted that the aim of the present study is to compare the production costs rather than evaluate the investment. Hence, it does not take into account impacts related to taxation, charges and other external factors such as loans etc., while all the costs are given in 2010 nominal values (€'10), avoiding the uncertainty deriving from inflation estimates. However, there has been a diversification in the discount rate (or, in other words, weighted average cost of capital, WACC) per technology, in order to reflect the degree of commercial maturity as well as the distinct operational characteristics.

---

[39] Foster, J., Wagner, L., Bratanova, A. (2014, April). «LCOE models: A comparison of the theoretical frameworks and key assumptions». www.uq.edu.au/eemg/docs/workingpapers/2014-4.pdf

[40] Ueckerdt, F. Hirth, L., Luderer, G., Edenhofer, O. (2013, December). «System LCOE: What are the costs of variable renewables?». Energy, Volume 63, 15 December 2013, Pages 61–75

3.2. Main assumptions and data

3.2.1 Ptolemaida V and Natural gas plants

The data used for calculating the Ptolemaida V LCOE derive from a previous study by WWF Greece and most of them have been made public by the PPC. The data for Natural Gas results from an analysis of studies that have been recently published[41,42,43,44,45,46]. The main techno-economic data used in the study are presented in Table 3.1.

Table 3.1: Techno-economic data for conventional plants

		Ptolemaida V	CCGT	OCGT
Investment cost	€/kW	2,106[47]	800	400
Fixed operational cost	€/kW/yr	40	20	15
Variable operational cost	€/MWh	-	0.60	35.00
Net efficiency	%	41.5%	60.0%	39.5%
CO_2 Emissions	kg/MWh	961[48]	350	550

Unlike RES, the electricity generation cost of the conventional units depends largely on fuel and CO_2 emissions costs. In the case of Ptolemaida V, the fuel cost is essentially equal to the cost for excavating lignite. In a previous study by WWF Greece, the excavation cost of lignite in Ptolemaida was found equal to 14.31 €/MWh$_f$. This is higher than the average 10,62 €/MWh$_f$, that was estimated in a Booz study carried out on behalf of PPC[49], comparing lignite production costs in Europe. Nevertheless, as that value referes to the average excavation costs for all of PPC's units, in this study it was decided to use the 14.31€/MWh$_f$ value and additionally conduct a sensitivity analysis.

Unlike lignite costs, which mostly depend on the characteristics of the particular deposit (excavation cost-lignite energy content), the cost of Natural Gas (NG) varies and depends on the international market of energy products. To date, the NG import costs in Greece differ from the equivalent European ones, as can bee seen in Figure 3.1, while the power industry costs are further increased by the regulated charges of the NG transport system.

However, assuming that NG prices will be assimilated at a European level at least as far as power generation is concerned, only the international price of NG has been used in this study, while –

---

[41] Fraunhoffer ISE. (2013, November). «Levelized Cost of Electricity - Renewable Energy Tecnologies». http://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-undkonzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf

[42] Prysma S.A., (2013, July). «Study on Cost and Business Comparison of Renewable vs. Non-renewable Technologies (RE-COST)». http://iea-retd.org/wp-content/uploads/2013/07/20130710-RE-COST-FINALREPORT.
pdf

[43] Black & Veatch. (2012, Φεβρουάριος). «Cost and performance data for power generation technologies». http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E

[44] BREE, Australian Energy Technology Assessment, 2012

[45] Department of Energy & Climate Change. (2013, December). «Electricity Generation Costs». https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

[46] Parsons Brinckerhoff. (2013, April). «Electricity Generation Cost Model - 2013 Update of Non-Renewable Technologies». https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223634/2013_Update_of_Non-Renewable_Technologies_FINAL.pdf

[47] Results from the overall cost made public by the PPC, equal to 1,390 m€

[48] PPC Directorate for the study and construction of HE. (2011, November). "Techno-economic Report for the Capture-Transportation and Storage of CO_2 for the new Ptolemaida V lignite plant of a 660 MWe gross nominal power"

[49] Press releas, PPC SA. (2014, June). "Booz study for the cost of lignite excavation in Europe, conducted on behalf of the PPC". https://www.dei.gr/el/i-dei/kentro-tupou/deltia-tupou/deltia-tupou-2014/iounios-2014/i-deikentro-tupoudeltia-tupoudeltia-tupou-2014ioun

similarly to the lignite calculations - taxes and charges were not taken into account. The analysis uses the projected prices for NG that are provided in the most recent EU impact assessment study on climate policies[50] (Figure 3.2).

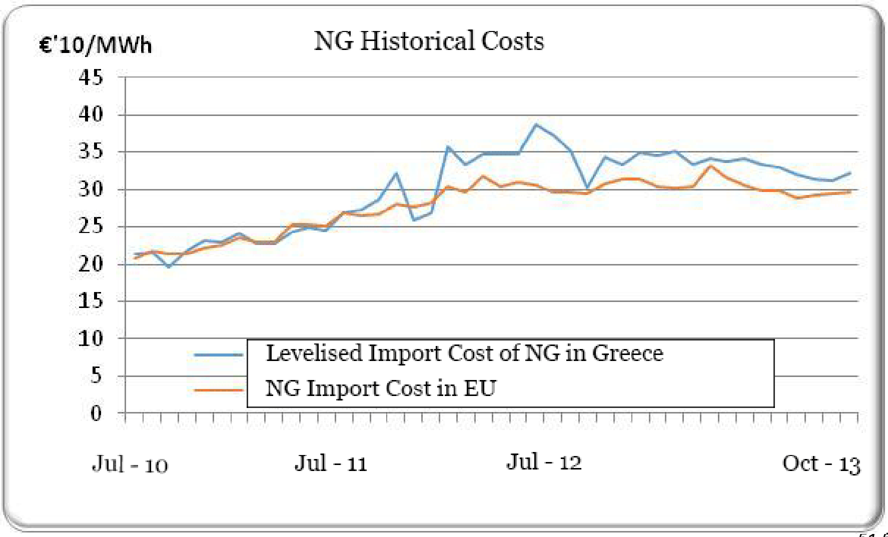


Figure 3.1. Historic development of NG import price in Greece and the EU[51,52]

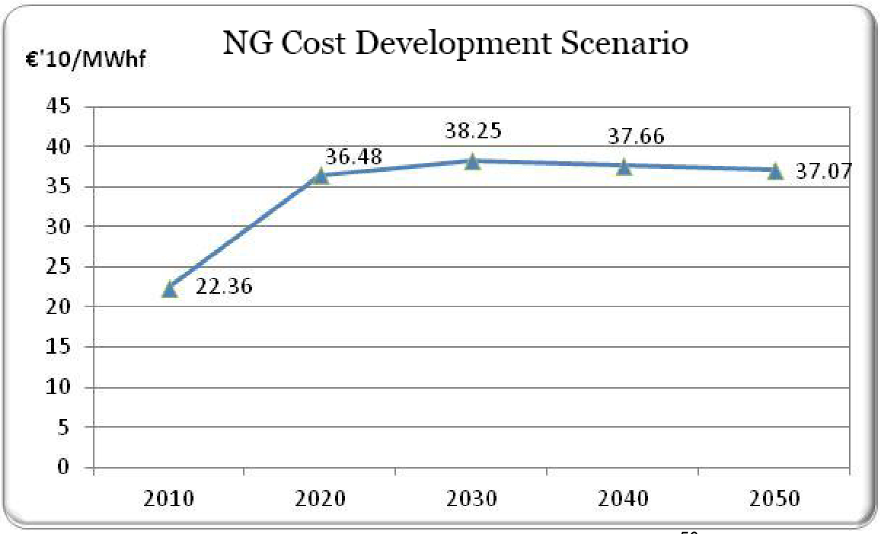


Figure 3.2. Price evolution for Natural Gas[50]

As is the case with RES, the capacity factor plays a crucial role in the final generation cost. But whereas in RES the energy produced is absorbed on a priority basis and is subject only to the technical limitations of the system, conventional power units are forced to operate in a competitive manner, and hence the capacity factor becomes dependant on market conditions. Besides, as the RES share in the system increases, the load that the conventional units need to meet is reduced, which has a major impact on their capacity factor[53]. Based on the EIA

[50] EC, SWD(2014) 15 final, Commission staff working document, Impact Assessment, Accompanying the document, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: A policy framework for climate and energy in the period from 2020 up to 2030. http://ec.europa.eu/smart-regulation/impact/ia_carried_out/docs/ia_2014/swd_2014_0015_en.pdf

[51] European Union Natural Gas Import Price. https://ycharts.com/indicators/europe_natural_gas_price

[52] RAE. (2014, 15 July). "Weighted average costs for importing natural gas in Greece" http://www.rae.gr/site/categories_new/about_rae/factsheets/2014/major/15072014.csp?viewMode=normal

[53] For example, in the WWF study on lignite plants, the Equivalent Operating hours (EOH) of Ptolemaida V were reduced from 8,146 EOH in 2020 down to 4,143 in 2050, as a result of high RES penetration[20]

(Environmental Impact Assessment) of Ptolemaida V[54], the nominal coefficient was taken as 80% (7,000 Equivalent Operating Hours) for Ptolemaida V and 46% (4,000 EOH) and 11%[55] (1,000 EOH) for the CCGT and OCGT units respectively.

3.2.2 RES Technologies

For the purpose of the study, the technologies chosen were those that have matured most (wind, photovoltaics, biogas, biomass and geothermal) as well as solar thermal, which despite its potential still remains undeveloped in Greece. Small hydro plants were not taken into account, since despite being a mature technology, their efficiency depends largely on local conditions and the over-decennial water cycles. In addition, the country's potential has mostly been realised or is about to be so in the years to come[56]. A distinction between large and small PV systems was made, as the economies of scale significantly alter the production costs of this technology.

The main techno-economic data for RES and NG resulted following a review of recent literature[41,42,43,44,45,46,57,58,59,60,61,62,63,64,65,66] as well as using empirical knowledge of the Greek market. Data for Ptolemaida V derived from PPC published data and the previous WWF Greece study[20].

Despite the fact that, as a result of the development of international competition, the equipment costs of RES can be considered almost uniform for all similar installations[67], the overall installation cost can differ significantly depending on the specific features of each installation (e.g. development cost and licensing, road construction and civil engineering projects et al.). As a result, a range of total installation cost was assumed and upper and lower limits were defined for the investment cost, in order to calculate the likely range of electricity production costs for each RES technology. The operational cost of each RES was taken into account as a fixed percentage of the investment cost.

The main cost of fuel-less technologies is the capital installation cost. Hence, the energy production cost depends largely on the annual energy produced, which also varies significantly

---

[54] PPC/DGPC. (2011, November). "Energy Impact Assessment – New Ptolemaida PP (Unitv V)"
[55] Open-cycle gas turbine cover mostly peaks and operate for only a few hours throughout the year. For example in 2013, the average capacity factor for open-cycle gas turbines hours was almost zero, according to IPTO's monthly bulletins.
[56] To date, RAE has handed out ~400 licenses for Micro Hydroelectric plants for more than 900MW of power
[57] Frankfurt School-UNEP Centre/BNEF. (2014). «Global Trends in Renewable Energy Investment 2014». http://www.unep.org/pdf/Green_energy_2013-Key_findings.pdf
[58] IRENA. (2013). Renewable Power Generation Costs in 2012: An Overview, http://www.irena.org/DocumentDownloads/Publications/Overview_Renewable%20Power%20Generation%20Costs%20in%202012.pdf
[59] EPIA. (2011, September). "Solar Photovoltaics Competing in the Energy Sector" http://www.epia.org/fileadmin/user_upload/Publications/Competing_Full_Report.pdf
[60] IEA. (2014). "Tracking Clean Energy Progress", OECD/IEA, Paris, http://www.iea.org/publications/freepublications/publication/Tracking_clean_energy_progress_2014.pdf
[61] NREL & IEA (2012, May). "Wind Task 26: The Past and Future Cost of Wind Energy". https://www.ieawind.org/index_page_postings/WP2_task26.pdf
[62] IEA. (2010). Renewable Energy Essentials, Geothermal, http://www.iea.org/publications/freepublications/publication/Geothermal_Essentials.pdf
[63] Poyry. (2013, June). «Technology supply curves for low carbon power generation». http://www.poyry.co.uk/sites/www.poyry.co.uk/files/325_technology_supply_curves_v5_1.pdf
[64] IEA. (2011). "Solar energy perspectives". http://www.iea.org/publications/freepublications/publication/solar_energy_perspectives2011.pdf
[65] IEA. 92013). "Technology Roadmap – Wind Energy". http://www.iea.org/publications/freepublications/publication/Wind_2013_Roadmap.pdf
[66] DiW Berlin. (2013, July). «Current and Prospective Costs of Electricity Generation until 2050». http://www.diw.de/documents/publikationen/73/diw_01.c.424566.de/diw_datadoc_2013-068.pdf
[67] It is worth noting that the RES equipment market is to a large extent globalized and shows great variations depending on international developments in offer and demand, as well as on international costs of raw materials, which have resulted to rather large variations in the past. However, a similar risk of exposure also lies with the cost of the basic equipment for thermal units.

depending on the site characteristics (e.g. wind potential). For this purpose, the study uses a range of annual energy production rates.

Unlike the aforementioned technologies, the main factors affecting the final production cost of biogas and biomass are fuel costs. Even in cases where raw materials can be provided at no cost or even at a profit (such as e.g. wtih industrial or agricultural waste), the end use is always related to various costs resulting e.g. from transportation, management etc. The cost also depends on the type of raw materials used. Hence, the present study is limited to examining bionatural gas plants that use a mixture of agricultural residues and livestock manure and biomass units using woodchips.

Since the size of the units also dictates the amount of raw materials used, the analysis was limited to relatively small units (1 MW for biogas and 5 MW for biomass), larger units having in general increased needs in terms of raw materials. In addition, collection and transportation costs in Greece are significant, and lead to reduced environmental benefits as a result of byproducts (e.g. CO_2 emissions) resulting from the overall management of raw materials. This analysis assumes a nominal value for raw material costs (fuel costs of 18€/MWh and 25€/MWh for biogas and biomass respectively), and a sensitivity analysis is conducted.

Finally, for the purpose of the analysis, solar thermal technology assumptions are based on parabolic trough storage technology data, while geothermal technology assumptions are based on high enthalpy binary cycle data.

The main data used in the economic analysis of the RES units are presented in Table 3.2, Table 3.3, Table 3.4 and Table 3.5.

Table 3.2: Development of wind energy Investment cost in €'10/kW

Year	Wind Energy - Land		Wind Energy - Sea	
	Low price	High price	Low price	High price
2014	1,000	1,500	3,000	5,000
2020	970	1,455	2,743	4,571
2030	920	1,380	2,473	4,121
2040	870	1,305	2,203	3,671
2050	820	1,230	1,933	3,221

Table 3.3: Development of PV Investment cost in €'10/kW

Year	PV - large		PV - small		PV - roofs	
	Low price	High price	Low price	High price	Low price	High price
2014	960	1650	1,250	1,750	1,500	2,150
2020	816	1403	1,063	1,488	1,275	1,828
2030	734	1262	956	1,339	1,148	1,645
2040	683	1174	889	1,245	1,067	1,530
2050	642	1103	836	1,170	1,003	1,438

Table 3.4: Development of the investment cost of biomass, biogas, solar thermal, and geothermal in €'10/kW

Year	Biogas		Biomass		Solar Thermal		Geothermal	
	Low price	High price	Low price	High price	Low price	High price	Low price	High price
2014	2,800	4,000	3,000	4,000	5,000	6,500	4,500	6,000
2020	2,520	3,600	2,700	3,600	4,500	5,850	4,050	5,400
2030	2,380	3,400	2,550	3,400	4,000	5,200	3,825	5,100
2040	2,240	3,200	2,400	3,200	3,500	4,550	3,600	4,800
2050	2,240	3,200	2,400	3,200	3,000	3,900	3,600	4,800

Table 3.5: Operational cost as a percentage of investment cost and range of annual production

RES Technology	Typical size of unit MW	Operational cost %	Annual production kWh/kW		
			Low	Average	High
Wind Energy - land	10	3.9%	1,752	2,179	3,066
Wind Energy - sea	50	2.1%	2,628	3,504	4,380
PV large	5	2.5%	1,300	1,500	1,700
PV small	0.1	1.5%	1,300	1,500	1,700
PV - roof	0.01	1.0%	1,100	1,400	1,700
Biogas	1	4.5%	7,008	7,446	7,884
Biomass	5	4.0%	7,008	7,446	7,884
Solar thermal	50	1.5%	1,752	2,628	3,504
Geothermal	50	2.5%	6,132	7,008	7,884

3.2.3 Cost development scenarios for CO2 emissions allowances

The allowance cost of CO_2 emissions, set by the EU Emissions Trading System (EU ETS), is currently at particularly low levels, ~6 €/tCO_2. However, the EU's increasing efforts regarding climate change make the use of the EU ETS a priority and are therefore bound to lead to an increase in allowance costs. The latest EU Impact Assessment regarding the proposed climate policies towards 2030 presents different price development scenarios for CO_2 emissions allowances, which for year 2050 range between 85 €/tCO_2 and 264 €/tCO_2, depending on the policies examined.

The present study uses, on the one hand, the figures provided in the reference scenario of the latest EU Energy Roadmap to 2050[68] and, on the other hand, the figures of the reference scenario and those of the further emissions reduction scenario without any additional measures taken, found in the latest study (32% and 40% emissions reductions respectively by 2030). The CO_2 emissions allowances prices are presented in Table 3.6.

[68] EC, SEC(2011) 1565 final. (2011, December). "Energy Roadmap to 2050 – Impact Assessment and scenario analysis"

Table 3.6: The CO2 emissions allowances prices that were used in the study

Scenario	CO_2 emissions allowance prices in €'10/t			
	2020	2030	2040	2050
Roadmap to 2050[68]	20	40	52	50
New reference scenario[50]	10	35	67.5	100
Further reductions scenario (GHG40r)[50]	10	40	152	264

3.3 Results and analysis

3.3.1 Conventional units

The calculation of the LCOE using the aforementioned basic assumptions for Ptolemaida V and the natural gas plants led to the results presented in Table 3.7. The LCOE of the basic reference scenario of the Energy Roadmap is comparable to that of the new reference scenario, due to the increased costs of the former during the medium-term 2020-2030 period, which balance the much higher costs of the latter in the long term (that are hence paid out in lower present values).

In the Roadmap and the New Reference scenarios, the Ptolemaida V LCOE is lower than that of the NG plants, reflecting thus the importance of fuel costs. However, that changes in the further reductions scenario (GHG40r), where one should also expect a reduction in the lignite plants' capacity factor and, adversely, an increase in that of the natural gas plants, which will further increase the cost difference, as will be demonstrated later on. The LCOE of OCGT units is in all cases clearly larger compared to the rest, mainly due to the low capacity factor and the inferior technical characteristics.

Table 3.7: Results of the main anaysis for the conventional units

Scenario	LCOE €'10/MWh		
	Ptolemaida V	CCGT	OCGT
Roadmap to 2050	99.80	117.28	193.86
New reference scenario	101.65	117.95	194.92
Further reductions scenario (GHG40r)	132.80	129.30	212.75

As the LCOE depends largely on factors of a considerable uncertainty, sensitivity analysis was performed in order to determine the effect that some of them have on the LCOE. Hence, the fluctuations of the LCOE of the Roadmap basic scenario were examined for ±20% variations in the installation cost and the fuel cost. The results in Figure 3.3 show that fuel cost is the main cost factor, especially with regards to NG. The installation cost affects the production cost of Ptolemaida V to a larger extent compared to NG plants.

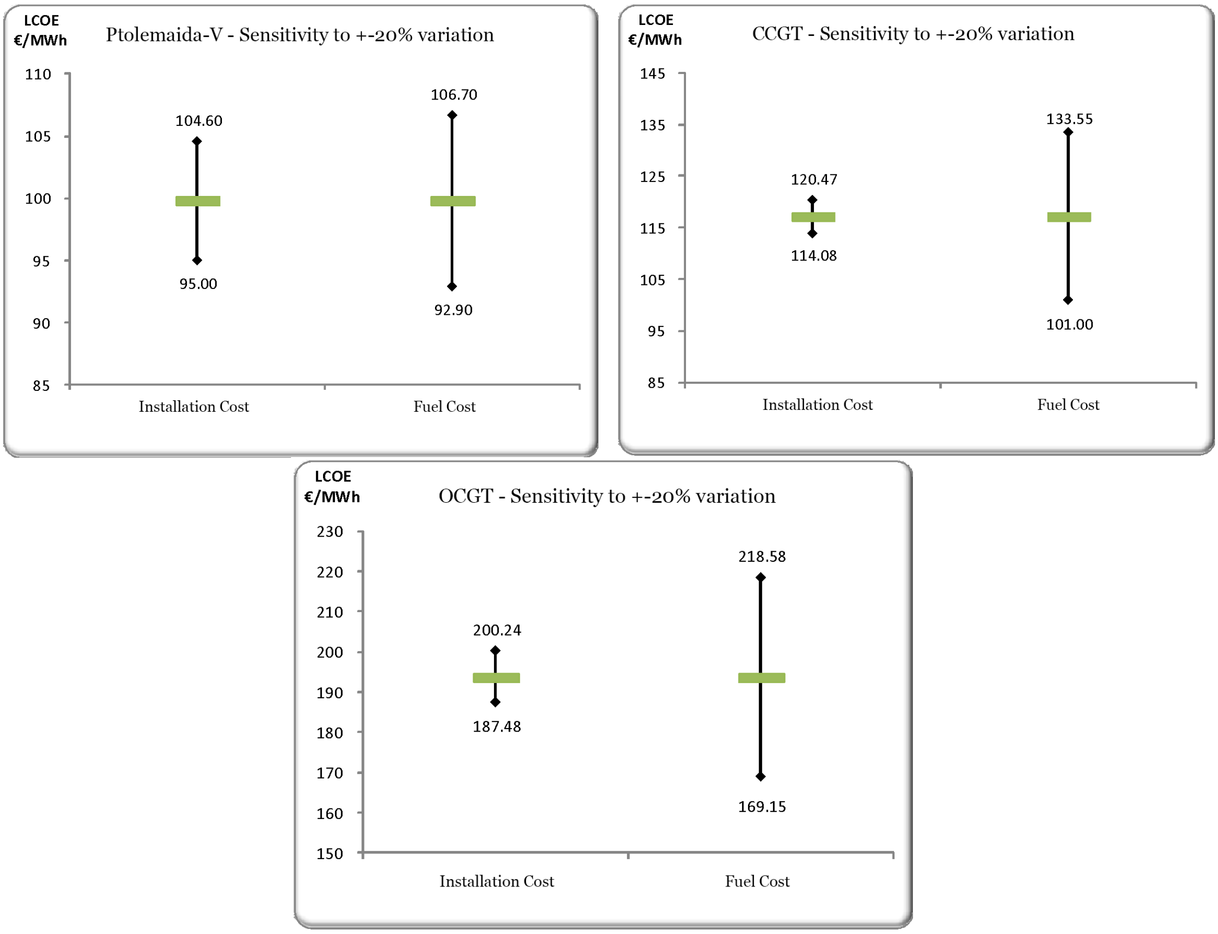
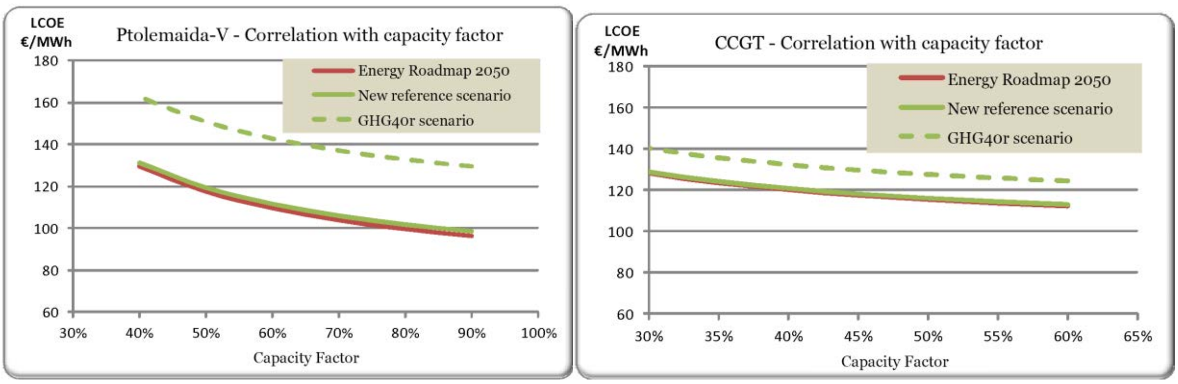


Figure 3.3. Sensitivity analysis for variations in the installation cost and the fuel cost of conventional technologies, a) Ptolemaida V, b) Natural Gas CCGT, c) Natural gas OCGT

Sensitivity analysis was also used to investigate the effect of variations in the capacity factor. The analysis was performed for all three CO_2 emissions allowances cost development scenarios, in order to estimate a price range for the LCOE of the thermal units. The results are presented in Figure 3.4. Both the discrepancy between the LCOE between the scenarios and the influence of the capacity factor are larger in the case of Ptolemaida V compared to NG plants, highlighting the importance of emissions costs and the risk of the investment. Comparing the charts for Ptolemaida V and OCGT, it also becomes evident that, even for the CO_2 emission allowances cost levels of the Roadmap 2050 and the new reference scenario, the LCOE of the competing technologies is starting to become comparable, while the respective cost of the lignite plant becomes significantly higher, as the emissions allowances prices go up.



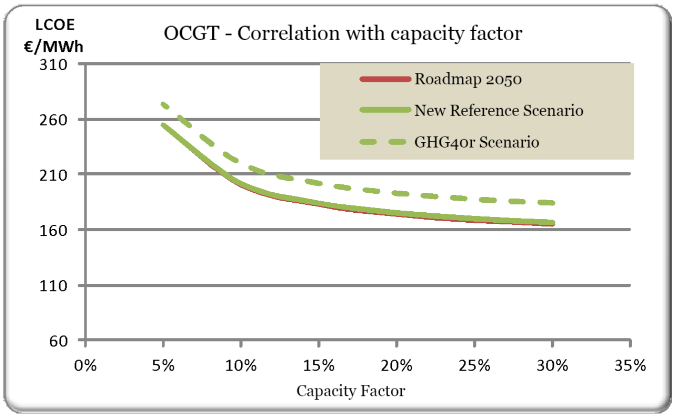


Figure 3.4. Sensitivity analysis for the capacity factor of three different CO_2 emissions allowances cost scenarios, a) Ptolemaida V, b) Natural gas CCGT, c) Natural gas OCGT

3.3.2 RES units

As was presented above, there is a significant value range in both the cost elements and the main operational characteristics of the various RES technologies. Excluding biogas and biomass, the most important cost element for RES technologies is the installation cost, while an important factor affecting the final unit generation cost is the potential of annual energy production, reflected by the capacity factor. As far as biogas and biomass are concerned, apart from the installation cost, trivial is the role of raw material costs, while the variation of the capacity factor is more controlled. Based on the above, and with the aim of drawing a clearer picture regarding the LCOE of RES, its complete range was calculated, i.e. from the case of the cheaper unit with the highest capacity factor (lower fuel price for biomass-biogas) to the case of the most expensive unit that has the lowest production possible (higher fuel price for biomass-biogas). In the interest of a better presentation of the results, the LCOE range for the installation cost, assuming an average capacity factor (or fuel cost in the cases of biomass-biogas), is given in dark blue color, while the additional variation is given in cyan, taking into account the range of the capacity factor (or fuel cost in the cases of biomass-biogas) (Figure 3.5). The results of the calculations are presented in Figure 3.6, factoring in the cost development for 2014-2020-2030-2040-2050. The highest and lowest LCOE calculated above is given in Table 3.8.

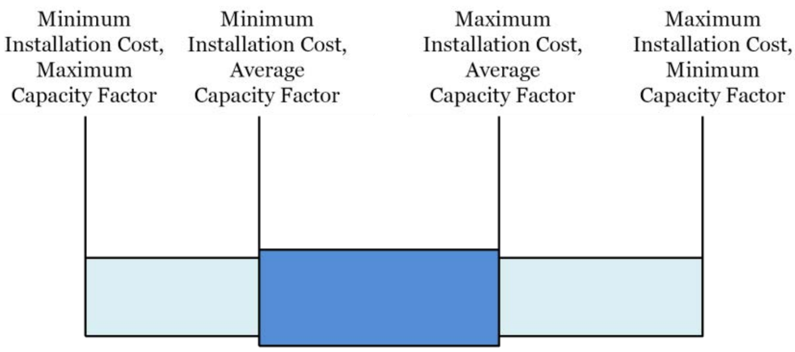


Figure 3.5. Graph explaining the way the LCOE range is presented

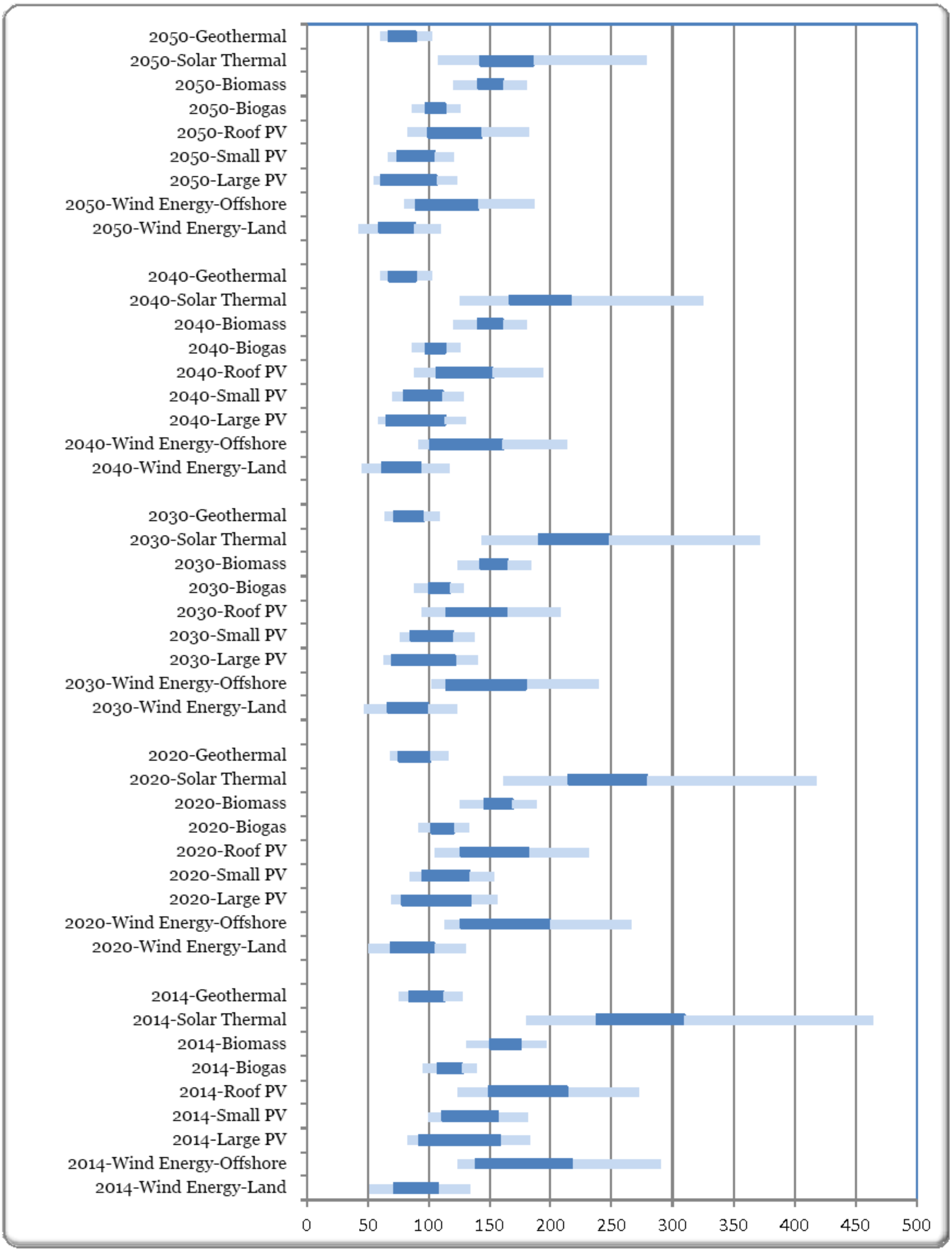


Figure 3.6. Calculation results for RES rechnologies installed in different years

Table 3.8: Lowest and highest LCOE for each RES technology

Year	Technology	LCOE (€10/MWh) minimum	LCOE (€10/MWh) maximum
2050	Geothermal	59.85	72.68
	Solar Thermal	107.16	200.04
	Biomass	120.34	140.34
	Biogas	85.65	97.65
	Roof PV	82.24	121.27
	Small PV	65.99	82.09
	Large PV	54.50	70.84
	WindEnergy - Offshore	79.45	126.27
	Wind Energy - Land	41.85	63.37
2040	Geothermal	59.85	72.68
	Solar Thermal	125.03	233.38
	Biomass	120.34	140.34
	Biogas	85.65	97.65
	Roof PV	87.49	129.02
	Small PV	70.20	87.33
	Large PV	57.98	75.36
	WindEnergy - Offshore	90.55	143.91
	Wind Energy - Land	44.40	67.23
2030	Geothermal	63.59	77.22
	Solar Thermal	142.89	266.72
	Biomass	122.87	142.87
	Biogas	88.01	100.01
	Roof PV	94.07	138.73
	Small PV	75.48	93.91
	Large PV	62.35	81.03
	WindEnergy - Offshore	101.65	161.55
	Wind Energy - Land	46.95	71.09
2020	Geothermal	67.34	81.76
	Solar Thermal	160.75	300.06
	Biomass	125.39	145.39
	Biogas	90.36	102.36
	Roof PV	104.52	154.14
	Small PV	83.87	104.34
	Large PV	69.27	90.03
	WindEnergy - Offshore	112.75	179.18
	Wind Energy - Land	49.50	74.96
2014	Geothermal	74.82	90.85
	Solar Thermal	178.61	333.40
	Biomass	130.43	150.43
	Biogas	95.07	107.07
	Roof PV	122.97	181.34
	Small PV	98.67	122.75
	Large PV	81.50	105.92
	WindEnergy - Offshore	123.32	195.98
	Wind Energy - Land	51.03	77.28

It is particularly interesting to compare the LCOE between RES and conventional units. In the figures that follow, the curves stand for the upper and lower limit of the LCOE of RES technologies. The shaded area represents the value range for the conventional units, for different emissions allowances cost development scenarios, and for different capacity factors.

Figure 3.7 and Figure 3.8 show a comparison between the 4 main RES technologies and the conventional units using natural gas (CCGT and OCGT respectively).

The results show that many RES technologies are already fully competitive with conventional technologies fuelled by natural gas, with the possible exception of offshore wind farms and solar thermal. Land-based wind farms and PV parks, especially of a larger scale, have a much lower LCOE compared to electricity production using natural gas.

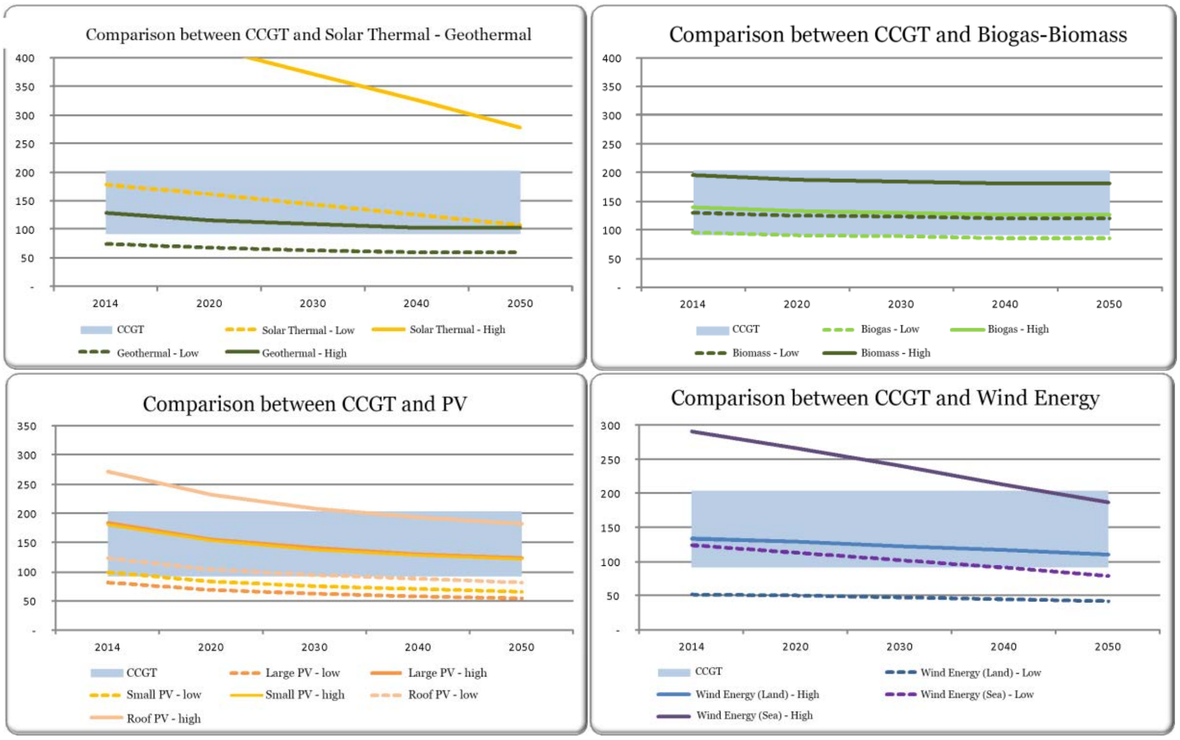


Figure 3.7. LCOE comparison between NG-CCGT and RES technologies

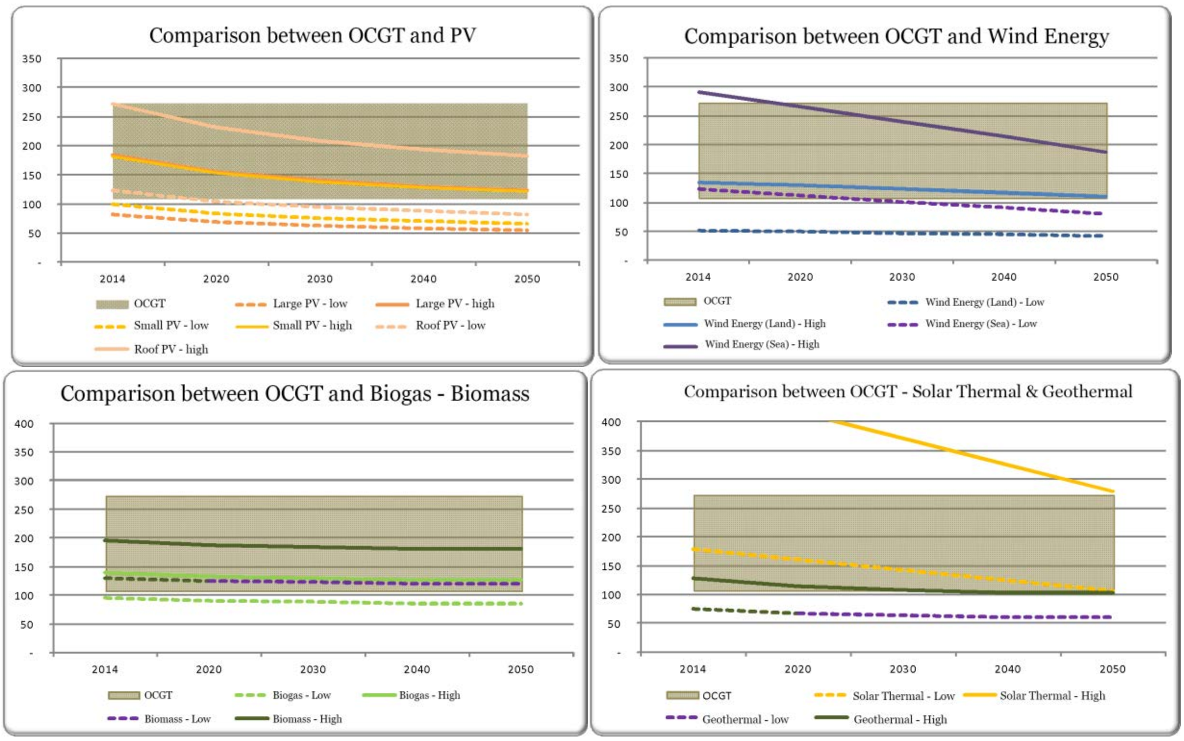


Figure 3.8. LCOE comparison between NG-OCGT and RES technologies

It is also interesting to compare RES technologies with Ptolemaida V (Figure 3.9), as it appears that land wind farms, large and medium PV and biogas can be fully competitive under certain circumstances. As the cost of these technologies is expected to drop in the future, this comparison will definitely favor RES.

Offshore wind farms become competitive with Ptolemaida V and the CCGT unit only when assuming low installation costs and high capacity factors. It appears that solar thermal technologies in Greece are marginally competitive; large reductions in installation costs would be necessary in order for them to compete with conventional plants in the future.

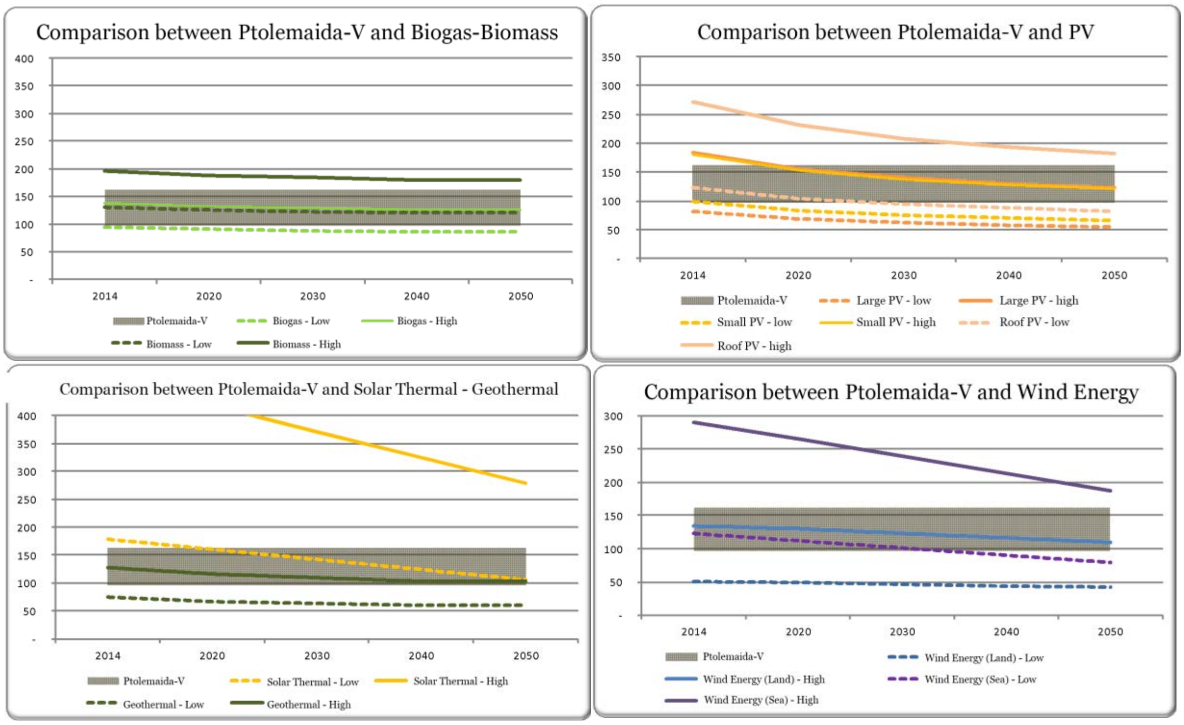


Figure 3.9. LCOE comparison between Ptolemaida V and RES technologies

4. RES AND ENERGY STORAGE

4.1 RES Technologies

Chapter 3 demonstrated that there are already mature RES technologies that – by Greek standards – are directly competitive with fossil fuel-based electricity production and specifically lignite.

From a broader perspective, the climate change policies that have been adopted on a global level and the steady increase and ongoing uncertainty regarding fossil fuel costs, have led to a continuous increase in the share of RES in the global energy mix, as is evident in Figure 4.1.

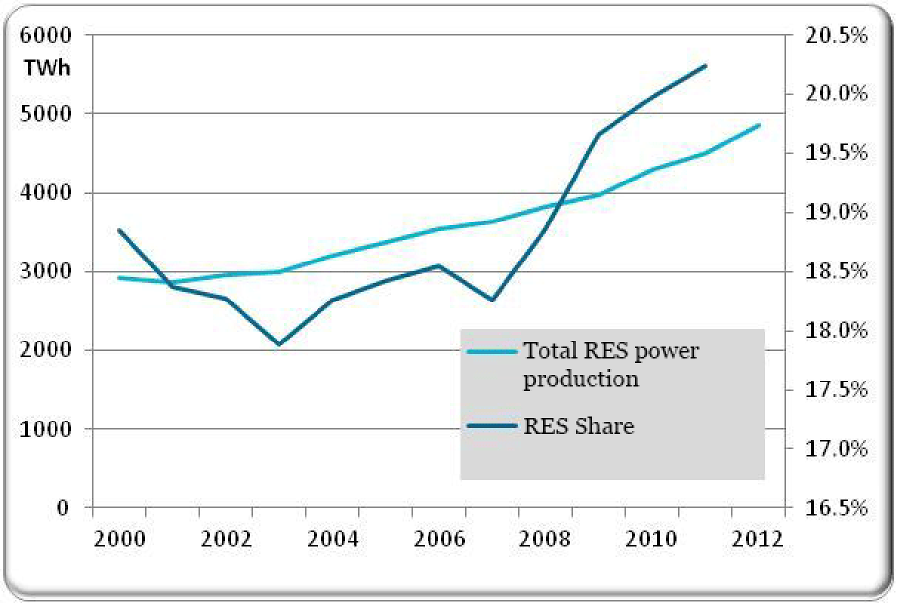


Figure 4.1. Development of RES produced power at a global scale (Based on IEA data)

Wind farms and PV parks are installed at a rather high rate at a global level (Figure 4.2)[69,70], reflecting thus the high interest in these sectors, in line with the need for climate change mitigation, protecting the environment and guaranteeing energy security.

[69] Global Wind Energy Council. (2014). Global status overview. http://www.gwec.net/global-figures/wind-energy-global-status/
[70] European Photovoltaic Industry Association. (2014). Global market outlook for photovoltaics 2014-2018. http://www.epia.org/news/publications/

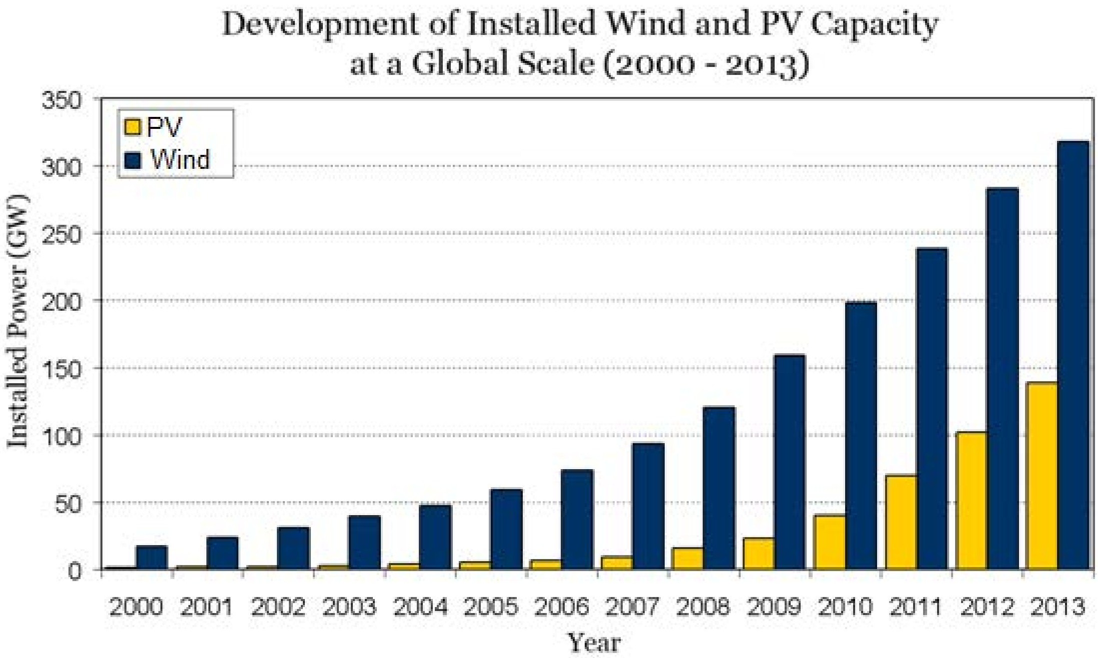


Figure 4.2. Development of wind and PV electricity production at a global level[69, 70]

The continuous increase in the use of RES technologies has lead to a drop in their costs, as a result of technical advancements and improvements in both their equipment production processes and their supply chain worldwide. As they gradually mature commercially, the cost for financing RES investments is also reduced. For example, the total investment costs dropped to $214 billion in 2013, compared to $250 billion in 2012. However, this reduction is largely due to an important drop in investment costs of RES technologies and especially PV, as according to a report by the Frankfurt School-UNEP Centre/BNEF, installing 39 GW of new PV cost 39% less compared to 2012[55]. This is better depicted in Figure 4.3, which shows the cost development of PV panels in Europe, while Figure 4.4 presents a medium-term estimate of the development of total PV installation costs in Europe till 2020. With the cost of PV panels today down to 0.5 €/W or less, and the installation cost of large PV parks dropping even below 800 €/kW, it seems that the reduction in PV costs is yet to be completed.

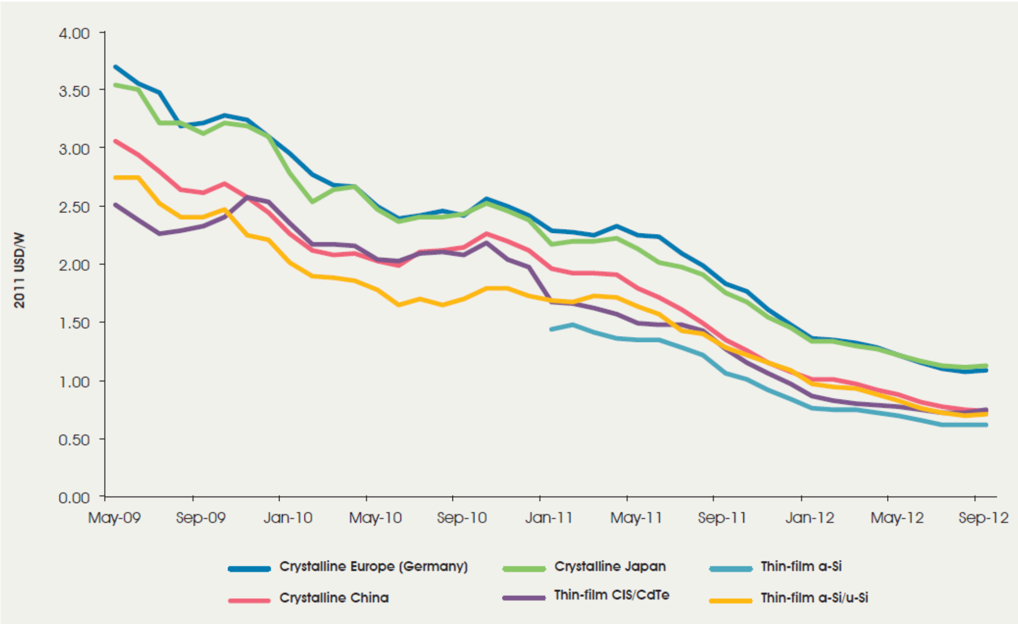


Figure 4.3. Cost development of PV panels in Europe[57]

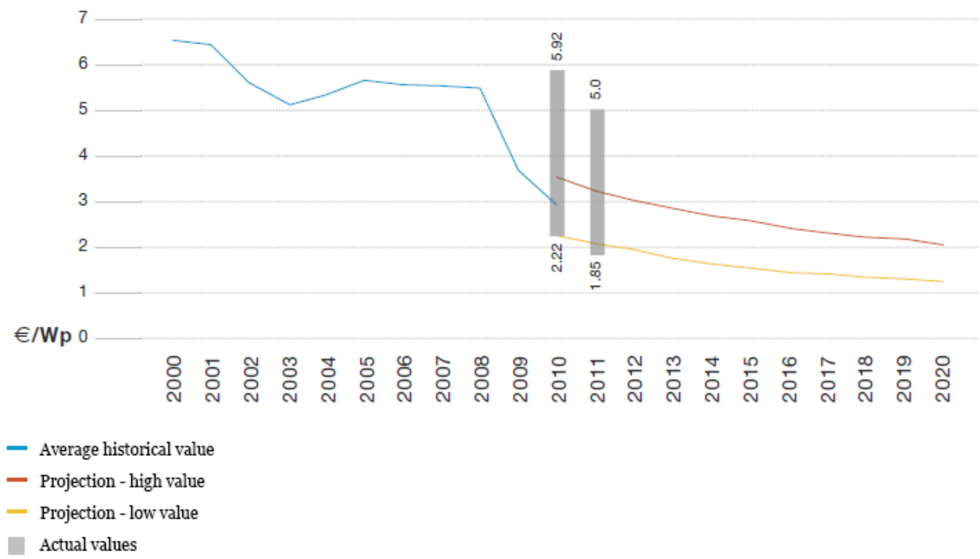


Figure 4.4. Medium-term prediction for the development of PV costs in Europe[57]

As far as wind energy is concerned, following a period of important reductions in costs per kWh installed (Figure 4.5) – mainly the result of advancements in technology and the economies of scale – an increase in costs was noted, largely due to an increase in the demand and costs of raw materials, as well as increases in turbine sizes (Figure 4.6). However, from 2008 onwards, wind farm installation costs appear to follow a reduction trend. At the same time, innovations in technology and increases in wind turbine sizes have led to an important increase in their capacity factor (Figure 4.7) and a subsequent reduction in overall production costs.

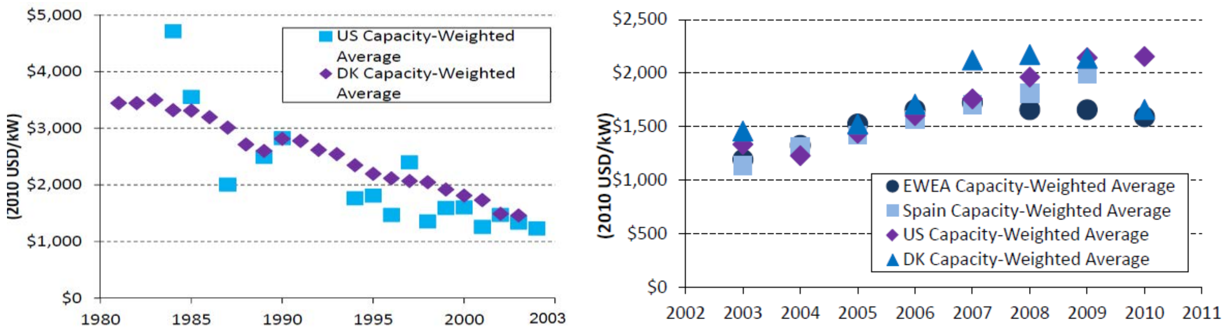


Figure 4.5. Variations in the total investment cost of wind farms[61].

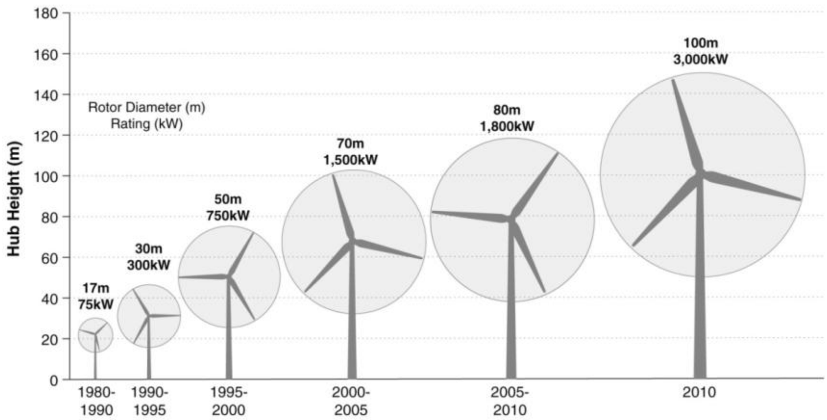


Figure 4.6. Graph showing the wind turbine increase in size[61].

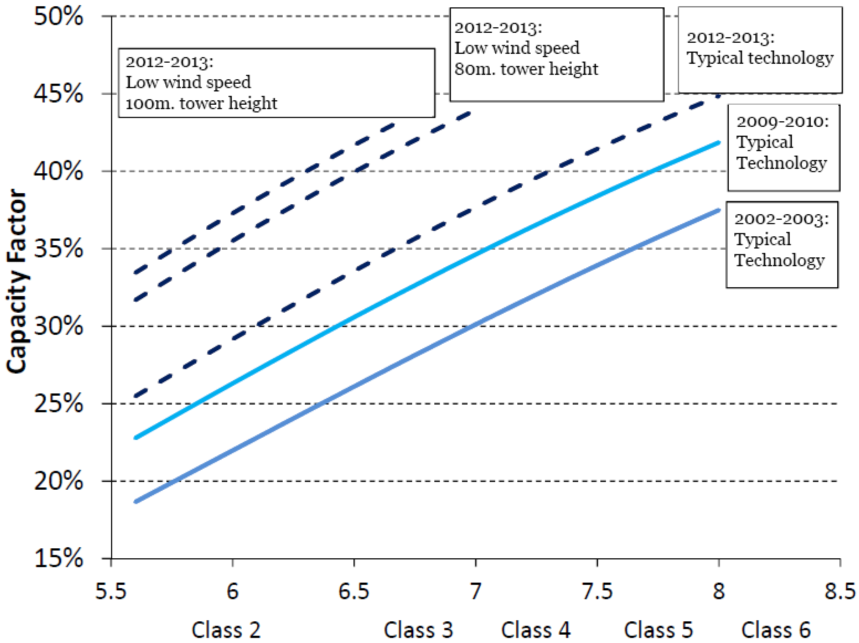


Figure 4.7. Analysis of the development of the capacity factor of wind turbines[61].

Unlike PV and wind, the use of geothermal energy is not widespread in Greece. Its growth came to a halt after an unsuccessful project of PPC in the island of Milos in the '80s, which had serious environmental impacts at a local level. Today, however, there are plans for exploiting the country's geothermal potential and PPC is already developing four projects amounting to a total of 23 MW of power.

Geothermal electricity production takes advantage of the high temperature of geothermal fluids to produce steam, which is then used in steam turbines. As it involves mostly conventional equipment and processes, the development of the units' cost is not in line with technological innovation. Besides, their cost is mainly associated with the cost of boreholes, which depends on the given geothermal field and can reach up to 35% of the total cost[62].

Figure 4.8 shows data on the installation costs of geothermal units – the wide range of the total cost is evident. Two of the main advantages of geothermal energy are its constant production and its high capacity factor, which can reach up to 90%; as a result, geothermal plants have small variations in electricity production over time, unlike wind and PV. Combined with the lack of fuel costs, overall geothermal production costs can be fully competitive with those of conventional units, depending on the geothermal field. Provided that geothermal stations are designed and operated under strict environmental regulations, geothermal energy can become part of a clean solution for electricity production.

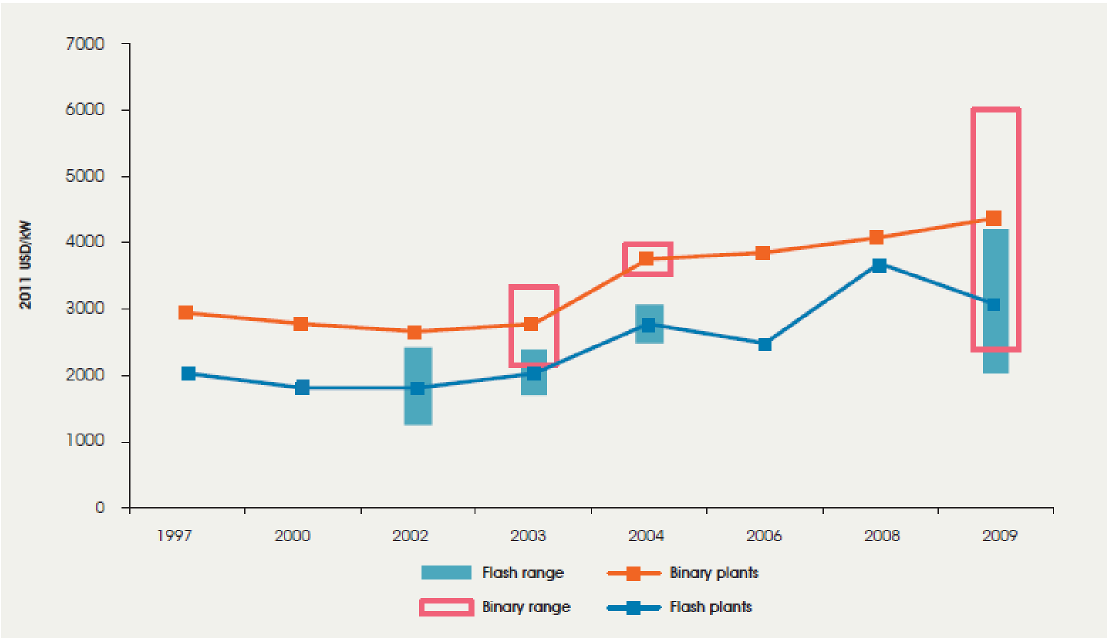


Figure 4.8. Cost development of installing geothermal units[58]

Conventional biomass and bionatural gas plants have many similarities to geothermal production as far as installation costs are concerned. There are various technologies that can be used to exploit biomass for energy purposes; the most suitable and directly applicable in Greece are dry biomass burning (in the form of wood-chips and pellets) and the anaerobic digestion of agricultural residues and livestock manure. Biomass and biogas also use conventional equipment, and important technological advances are not to be expected. The main production cost factor is the supply cost of biomass, which depends on the proximity of the unit to biomass that meets the appropriate quality characteristics (calorific value, humidity, composition etc.).

Using solar radiation in solar thermal power plants can also become part of RES production in Greece. The main principle behind this technology lies in using reflectors to concentrate direct solar radiation at a designated focal point, with the aim of producing steam and using it in a steam engine. Surplus heat storage devices can further extend the operation of solar thermal plants beyond the expected hours of sunshine.

4.2 Challenges for achieving an increase in RES share

Increasing the RES share in the energy mix, especially with regards to wind and PV, is far from easy[71,72,73] and requires an adoption of specific strategies and supportive measures[74,75]. More specifically, as a result of the intermittent and fluctuating nature of energy production using RES, it becomes almost impossible to regulate it, undermining the ability to meet power demands in a satisfactory way. One can easily draw that as the share of RES in the energy mix increases, so does the degree of uncertainty in terms of production, making thus the energy management of such systems particularly difficult[76,77]. This becomes even more of an issue in weaker networks (micro-grids), whose systems are limited in terms of balancing ability[78]. The above leads to the energy produced by RES being rejected, an outcome directly linked to the given power network's flexibility levels/absorption ability of the total production (e.g. minimum load of thermal units); on the other hand, it leads to a need for fast-response backup units, which can adequately cover any energy shortages in the demand that result from the variable production of RES.

There are various well-established and modern approaches that deal with the issues arising from an increased RES share in the power mix:

- Wide spatial dispersion of RES facilities, combined with exploiting different sources (hybrid systems), in order to increase their complementarity as much as possible[79].
- Adopting demand and management strategies, in order to sync the variable RES production with the actual consumption, taking into account the need for implementing efficient methods for estimating the load demand and RES production[80].
- Reinforcing existing power networks and international energy trade, with the aim of increasing the balancing potential between different zones/power systems[81].
- Using energy storage systems to store and use RES surplus to cover production shortages and satisfy electricity demand[82,83].

---

[71] Cifor, Angela, Denholm, Paul, Ela, Erik, Hodge, Bri-Mathias, Reed, Adam. (2014, 23 December). «The policy and institutional challenges of grid integration of renewable energy in the western United States». Utilities Policy, In Press, Corrected Proof. http://www.sciencedirect.com/science/article/pii/S0957178714000824
[72] Gaviano, Antonello, Weber, Karl, Dirmeier, Christian. (2012). «Challenges and Integration of PV and Wind Energy Facilities from a Smart Grid Point of View». Energy Procedia, Volume 25, 2012, Pages 118-125
[73] Voumvoulakis, E., Asimakopoulou, G., Danchev, S., Maniatis, G., Tsakanikas, A.. (2012, November). «Large scale integration of intermittent renewable energy sources in the Greek power sector». Energy Policy, Volume 50, Pages 161-173
[74] Zafirakis, D., Chalvatzis, J.K., Baiocchi, G., Daskalakis, G.. (2013, May). «Modeling of financial incentives for investments in energy storage systems that promote the large-scale integration of wind energy». Applied Energy, Volume 105, Pages 138-154
[75] Veena, P., Indragandhi, V., Jeyabharath, R., Subramaniyaswamy, V.. (2014, June). «Review of grid integration schemes for renewable power generation system». Renewable and Sustainable Energy Reviews, Volume 34, Pages 628-641
[76] Kaldellis, J.K., (2007, June). «Maximum wind energy contribution in autonomous electrical grids based on thermal power stations». Applied Thermal Engineering, Volume 27, Issues 8–9, Pages 1565-1573
[77] Kaldellis, J.K., Kavadias, K.A., Filios, A.E. (2009, July). «A new computational algorithm for the calculation of maximum wind energy penetration in autonomous electrical generation systems Applied Energy, Volume 86, Issues 7–8, July–August 2009, Pages 1011-1023
[78] Papathanassiou, S.A., Boulaxis, N. G. (2006). «Power limitations and energy yield evaluation for wind farms operating in island systems». Renewable Energy, Volume 31, Issue 4, April 2006, Pages 457-479
[79] Santos-Alamillos, F.J., Pozo Vázquez, D., Ruiz-Arias, J.A., Lara-Fanego, V., Tovar-Pescador, J. (2014). «A methodology for evaluating the spatial variability of wind energy resources: Application to assess the potential contribution of wind energy to baseload power». Renewable Energy, Volume 69, September 2014, Pages 147-156
[80] Pina, André, Silva, Carlos, Ferrão, Paulo. (2012). «The impact of demand side management strategies in the penetration of renewable electricity». Energy, Volume 41, Issue 1, May 2012, Pages 128-137
[81] Arturs Purvins, Heinz Wilkening, Gianluca Fulli, Evangelos Tzimas, Gianni Celli, Susanna Mocci, Fabrizio Pilo, Sergio Tedde. (2011). «A European supergrid for renewable energy: local impacts and far-reaching challenges». Journal of Cleaner Production, Volume 19, Issues 17–18, November–December 2011, Pages 1909-1916
[82] Zafirakis D. (2010). "Overview of energy storage technologies for renewable energy systems", in: Stand-alone and hybrid wind energy systems: Technology, energy storage and applications (ISBN 1 84569 527 5), Woodhead Publishing Limited, Abington Hall, Abington, Cambridge, CB21 6AH, UK
[83] Zafirakis D.. (2015). "Modern Energy Storage Applications", in: Handbook of Clean Energy Systems, Volume of Energy Storage, Wiley

4.3 The role of energy storage

Despite the fact that energy storage is used in various applications nowadays, the wider integration of energy storage technologies in the power sector is often met with skepticism, with some exceptions in large-scale applications.

However, and as a result of the need for a surge in the overall contribution of RES, there has been an important increase in energy storage-related research over the past decade. Crucial to the field's development is the existence of various technologies, some of which are mature and others less so, of distinct characteristics and capabilities that as a whole can be used in a wide range of applications (Figure 4.9 and Figure 4.10). More specifically, energy storage technologies are divided into two main categories: those used in power quality applications[84] and those used in energy management applications[83].

The first category is limited in terms of energy autonomy but offers rapid load/unload as well as the ability to perform multiple operational cycles. It includes small-scale energy storage systems, such as e.g. flywheels, super capacitors and superconducting magnetic energy storage systems (Figure 4.9).

The second category includes large-scale energy storage technologies, such as pumped hydro energy storage and compressed air energy storage, and is defined by high storage capacity/autonomy and the ability to be used in utility scale applications. Over the years however, the boundaries between the two categories are becoming blurred, as the technological development of energy storage systems is driven to a large extent by the need to meet increased needs that will attribute a greater value to their operation.

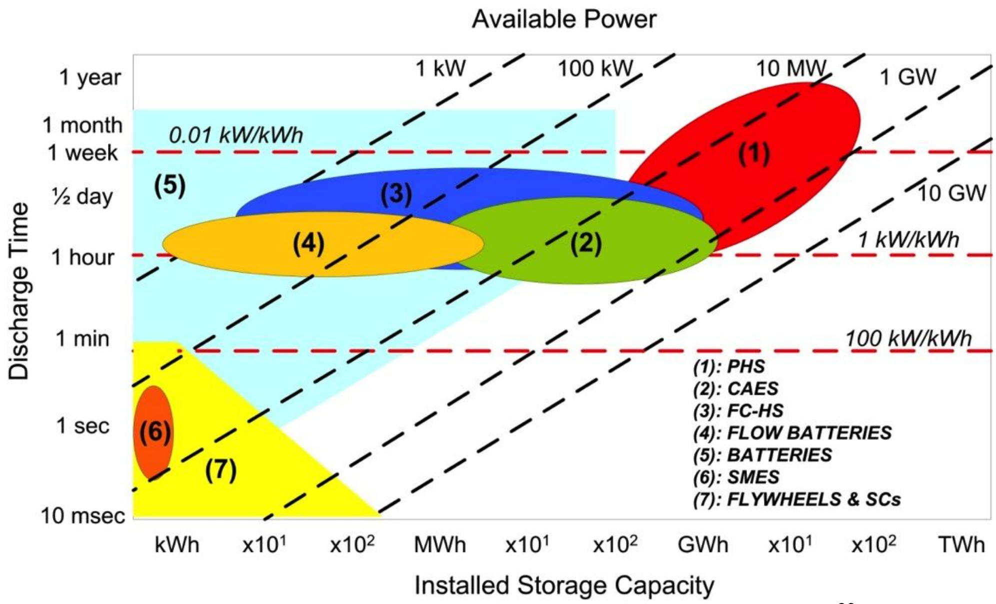


Figure 4.9. A comparison between energy storage systems[82]

[84] The term "power quality" refers here to frequency, voltage and harmony control network applications, aimed at maintaining the desired characteristics that ensure its smooth operation.

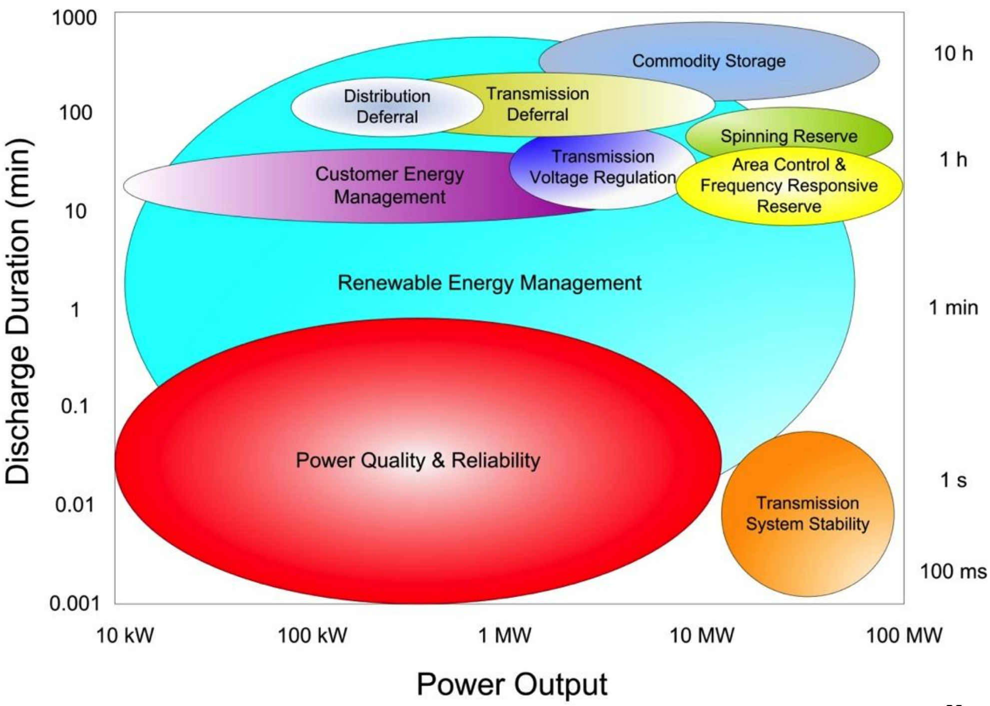


Figure 4.10. Field of contemporary application for energy storage technologies[82]

Crucial to the acceleration of this trend are the developments in the field of accumulators. Over the past decade, this sector has shown great improvements as fas as medium and large-scale applications are concerned, as new, innovative technologies support a range of services that meet the demands of both energy management and power quality. In this context, modern energy storage technologies face a number of challenges that are not limited to their compatibility with RES, but further include applications such as spinning reserve[85], peak shaving, transmission/distribution deferral, and more (Figure 4.10).

The recent efforts in the field of policy making are also important, in terms of promoting these systems using financial instruments and support mechanisms that will allow the energy storage technology market to open up, gradually leading to the maturing of the technologies and hence the reduction of their currently high cost[74, 86]. In this direction, it is crucial to establish a clear and detailed evaluation framework for the services offered by energy storage technologies[87], with an emphasis on achieving an increased RES percentage share in the electricity mix.

4.4 Pumped hydro energy storage (PHES)

Despite the important developments in the accumulators sector over the past years, pumped hydro energy storage is still the most mature solution as far as energy management applications at a power network level are concerned. In effect, the total installed capacity of such systems at a global level is approximately 130GW[88], which is comparable to that of PVs.

---

[85] Spinning reserve refers to the available power of an on-line unit, which can provide instant support in case of a frequency drop in the power system.

[86] Goran Krajačić, Neven Duić, Antonis Tsikalakis, Manos Zoulias, George Caralis, Eirini Panteri, Maria da Graça Carvalho. (2011). «Feed-in tariffs for promotion of energy storage technologies». Energy Policy, Volume 39, Issue 3, March 2011, Pages 1410-1425

[87] Ramteen Sioshansi, Paul Denholm, Thomas Jenkin, Jurgen Weiss. (2009). «Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects». Energy Economics, Volume 31, Issue 2, March 2009, Pages 269-277

[88] Alstom. (2011). Pumped hydro energy storage Power Plants. http://www.alstom.com/Global/Power/Resources/Documents/Brochures/hydro-pumped hydro energy storage-power-plant.pdf

PHES technology first appeared around 1890 in Italy and Switzerland, while the first reversible hydroelectric turbines became available in 1930 and contributed significantly to the widespread use of the technology; taking place mostly in USA and Japan, it was partly the result of the need to manage the electricity that was produced in nuclear plants. PHES constitutes today approximately 99% of the installed storage capacity of power applications worldwide[89], demonstrating a keen potential that nevertheless requires further investigation and more detailed mapping.

Indicative of the magnitude of pumped hydro energy storage stations is the fact that the installed capacity of the ten largest stations worldwide (see Table 4.1)[90] adds up to 20GW, the largest one being in Virginia, Bath Country, USA (3GW).

Table 4.1: Ten largest pumped hydro energy storage stations worldwide (2013)[90]

N/N	Plant Name	Country	Capacity (GW)
1	Bath County	USA	3,003
2	Huizhou	China	2,448
3	Guangdong	China	2,400
4	Okutataragi	Japan	1,932
5	Ludington	USA	1,872
6	Tianhuangping	China	1,836
7	Grand'Maison Dam	France	1,800
8	Dinorwig	United Kingdom	1,728
9	Raccoon Mountain	USA	1,652
10	Mingtan	Taiwan	1,602

Figure 4.11. Pumped hydro energy storage stations in (a) Pennsylvania – USA (source: Margaret Luzier, U.S. Army Corps of Engineers) and (b) Okinawa - Japan (source: Agency of Natural Resources and Energy Japan)

---

89 Electric Power Research Institute. (2010, December). «Electricity Energy Storage Technology Options. A White Paper Primer on Applications, Costs, and Benefits» http://www.epri.com/abstracts/pages/productabstract.aspx?ProductID=000000000001020676

90 Hino, T., Lejeune A., 6.15 - Pumped Storage Hydropower Developments. Reference Module in Earth Systems and Environmental Sciences, from Comprehensive Renewable Energy, Volume 6, 2012, Pages 405-434

PHES consists in converting electricity to potential energy during storage, and visa versa during generation. The energy is stored by pumping water, and is produced by releasing it to hydro turbines. The system also includes two reservoirs installed at an appropriate height difference, the upper and lower, as well as a circuit of pipes for circulating water. Variations of the system can include only one pipe combined with a reversible hydro turbine, as well as a subsidiary pumping station. Of particular interest is the use of the sea as a lower reservoir, as is the case with the Okinawa plant in Japan (Figure 4.11b).

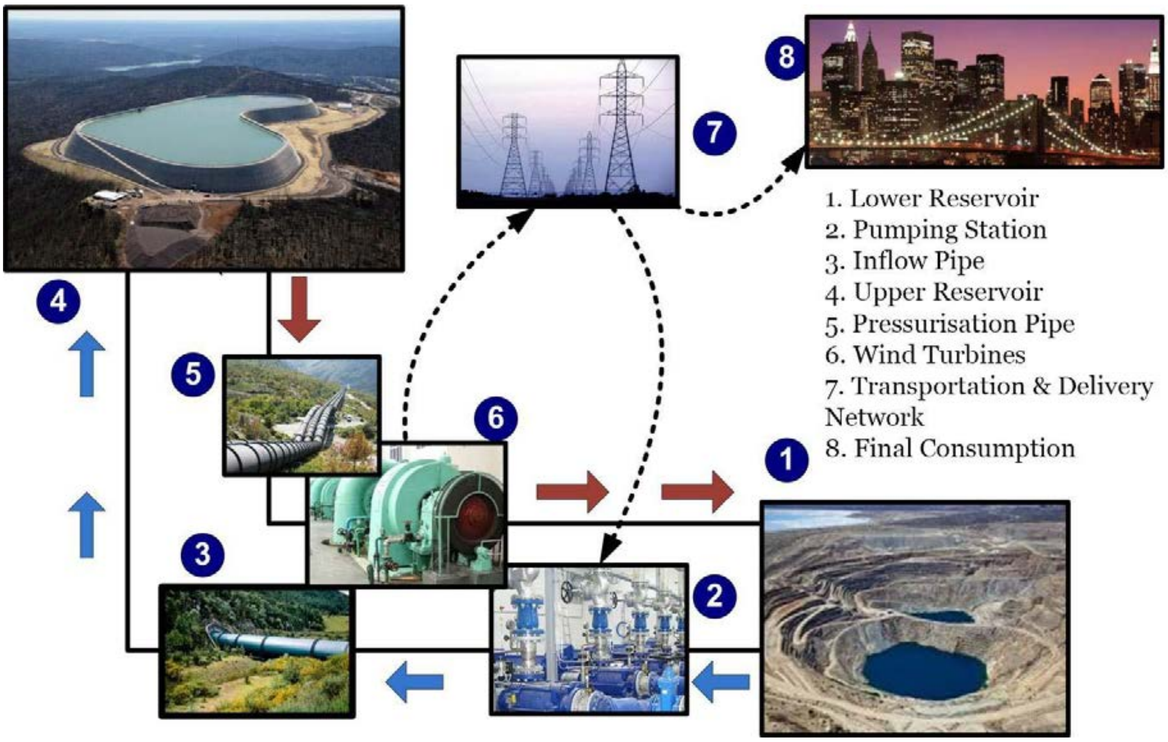


Figure 4.12. A typical schematic of a pumped hydro energy storage plant.

An important characteristic of such systems is their available storage volume, which combined with the working height differential (net available elevation) defines the storage capacity. For example, a net available elevation of 100m corresponds to a useful energy density of 0.25kWh/m^3 or 250MWh/Mm^3 of stored water, directly proportional to the leverage of height differential. The overall efficiency lies between 70%-75%[91], as a full energy cycle includes many losses during both pumping and production (hydro turbines - generators). Storage for extended periods can cause additional losses, such as the ones related to water evaporating from the reservoir.

Finally, an important advantage of PHES stations is their fast response and the almost immediate adjustment to load variations. To give an example, the Dinorwig PHES station in northern Whales can bear a load of ~1.7GW in less than 16 seconds[92], which runs completely counter to the low levels of flexibility of conventional thermal units, and especially nuclear and lignite (Table 4.2), whose equivalent responses increase significantly (40 hours for nuclear and 6-10 hours for lignite, for cold and warm reserve respectively)[93].

---

[91] Papantonis D.. (2009). "Hydrodynamic generators, pumps – wind turbines, hydrodynamic transmissions." Symeon, ISBN 978-960-9400-13-8

[92] European Association for Storage of Energy, http://www.ease-storage.eu/demonstrator.html?show=508

[93] Eurelectric. (2011). "Flexible Generation. Backing up Renewables". http://www.eurelectric.org/media/61388/flexibility_report_final-2011-102-0003-01-e.pdf

Table 4.2: Start-up times and load gradient for various power generation technologies[93]

	Nuclear	Lignite	Natural Gas	PHES
Start-up Time ‘cold’	~40 hours	~10 hours	<2 hours	~0.1 hours
Start-up Time ‘warm’	~40 hours	~6 hours	<1.5 hours	~0.1 hours
Load Gradient (up)	~5%/min.	~2%/min.	~4%/min.	>40%/min.
Load Gradient (down)	~5%/min.	~2%/min.	~4%/min.	>40%/min.
Minimum load	50%	40%	<50%	~15%

5. LARGE-SCALE ALTERNATIVES: HYBRID RES SYSTEMS USING PUMPED HYDRO ENERGY STORAGE

The comparison between RES technologies and Ptolemaida V in Chapter 3 proved that certain technologies – and especially wind and PV – are already competitive compared to conventional lignite production in terms of levelized cost of energy (LCOE), for a wide range of parameters. Still, it's not technically feasible to fully meet the base load that corresponds to Ptolemaida V using wind and PV, due to their intermittent nature of production. This contingency however, as was pointed out in chapter 4, can be dealt with by combining various RES technologies and pumped hydro energy storage. In that sense, a hybrid RES-PHES system can in theory substitute a base plant such as Ptolemaida V. Hence, this chapter examines the possibility of replacing the new Ptolemaida V lignite plant with a combined, hybrid solution involving RES and PHES, and also performs a comparative economic analysis.

5.1 Description of the proposed solution

The hybrid solutions examined include, apart from PHES units, sufficient wind and PV capacity in order to replace the base load covered by the new lignite plant.

The procedure followed differs from that of recent studies[94], which approach energy storage from the perspective of using the production residuals of RES in the National Interconnected System (NIS). More specifically, the strategy endorsed in the current study favours - through the use of PHES– meeting certain base load demands. This allows to take advantage of the complementarity between the country's wind and solar potentials, as was highlighted in Chapter 2 (Figure 2.6 και Figure 2.7), while PHES is additionally used to take advantage of the residuals as a priority at a first stage, rather than retrospectively. This largely eliminates the uncertainty associated with RES production, as the load base demands are instantly dealt with, by virtue of the low response time of PHES units (Table 4.2). The proposed approach further benefits by the fact that the rejected part of RES production (variable part) is indirectly reduced, as the increased RES contribution in meeting the base load reduces the system's minimum load that result from the operation of less flexible thermal units, as, to a large extent, these also define the amount of rejected excess electricity produced by RES.

More specifically, the rejected by the NIS energy produced by RES was calculated assuming a weighted average annual increase of 2.3% in power demand, in line with IPTO's scenario23, and a system's minimum load of about 4 GW (approximately 40% of the installed capacity of the existing thermal units), without taking into account the potential of exports using international connections. The calculation method for the variable energy surplus of RES is presented in detail in Annex 1.

In this context, various combinations of wind and PV capacity were considered. In particular, the analysis examined a 5 GW range for both wind (N_{wt}) and PV (N_{pv}) capacity. It should be pointed out that, as of now, the installed wind and PV capacity of the mainland network is approximately 1.91 GW and 2.2 GW respectively. The target for 2020 is to reach 7.5 GW of wind capacity, and maintain today's 2.2 GW of PV capacity. At the same time, and according to the national energy roadmap's 'RES Maximisation Measures' scenario for 2030[95], wind capacity is estimated at approximately 10 GW, whereas the equivalent PV capacity exceeds 5 GW. Hence, the above variation range can be considered moderate regarding wind, and more optimistic regarding PV, but in both cases lies within the limits of the mid-longterm national energy plan.

[94] Anagnostopoulos, J, Papantonis, D. (2013). Store Project, Facilitating energy storage to allow high penetration of intermittent renewable energy, D5.1 – GREECE, Overview of the electricity system status and its future development scenarios – Assessment of the energy storage infrastructure needs
[95] Ministry of Environment, Energy and Climate Change. (2012, March). National Energy Action Plan – Roadmap to 2050

Regarding the maximum PHES capacity examined, according to a recent study for estimating the PHES potential in European countries[96], it was found that the national PHES potential could under certain conditions exceed 1 TWh. This storage capacity is equivalent to 6.5-7.0 days of autonomy for the NIS, which translates to increased flexibility for the energy management of the mainland's power network, with an available elevation ranging between 250m and 600m (Figure 5.1).

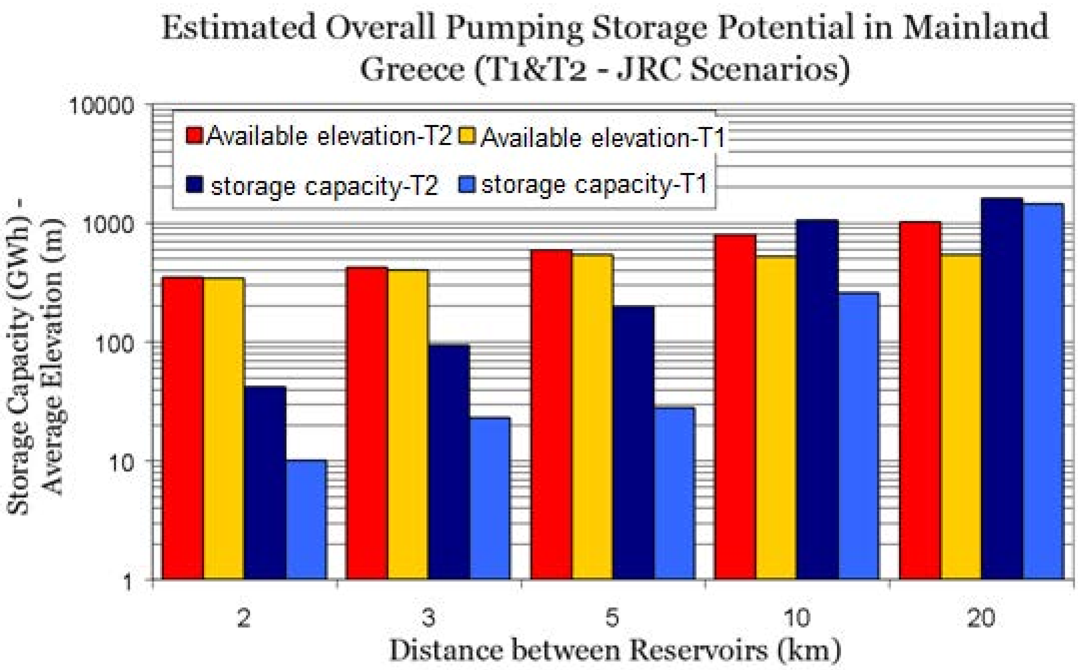


Figure 5.1. Estimated Greek pumped hydro energy storage potential

However, this study will not examine the case of completely new PHES stations, but will rather investigate the potential for meeting a load equivalent to that of Ptolemaida V through converting existing, in-series hydroelectric power units into PHES stations. This choice is made for both economical and environmental purposes.

From a construction perspective, converting existing hydroelectric units to PHES units requires the installation of pumping pipes and pumping systems, which translates to drastic cuts in installation costs, as well as to fending off excessive environmental damage caused by building new reservoirs from scratch. According to a study conducted on behalf of the Regulatory Authority for Energy (RAE)[97], there are 7 pairs of existing hydroelectric units that require minor interventions in order to be converted to PHES units (see Table 5.1). The unit installation cost of 400 MW of pumping capacity has been estimated at 520 €/kW.

The storage capacity of the PHES units to be converted is directly linked to the exploitation margin of the lower reservoir's potential, in a way that keeps intact the existing operating philosophy of the second hydro power unit in line. Besides, the volume of the upper reservoir is in every case larger – even by a multitude – compared to that of the lower one (Table 5.1), offering thus the ability to collect water for storage without overflowing. It is also noteworthy that the installed capacity of these units adds up to approximately 2 GW, exceeding thus the net

[96] Marcos Gimeno-Gutiérrez Roberto Lacal-Arántegui. (2013). «Assessment of the European potential for pumped hydropower energy storage - A GIS-based assessment of pumped hydropower storage potential». European Commission, Joint Research Centre, Institute for Energy and Transport. https://ec.europa.eu/jrc/sites/default/files/jrc_20130503_assessment_european_phs_potential.pdf
[97] Investigating the construction potential of new pumped hydro energy storage stations in Greece. Stefanakos I., NTUA: Research project 62/2423 (Construction potential of pumped hydro energy storage projects in Mainland Greece).

power output of Ptolemaida V, while the existence of a total of 21 hydro turbine units offers increased flexibility with regards to managing the load uptake.

The maximum storage capacity of these units was calculated at 40 GWh, which is far greater than the required storage capacity of 15-30 GWh that was estimated in order for the NIS to effectively regain the rejected RES production, as part of achieving the 40% target of RES participation in the power mix by 2020[94].

However, using all of the 40 GWh capacity shouldn't be taken for granted, due to the various current uses of the reservoirs. In order to make a realistic estimate regarding the maximum usage rate of the available storage capacity of the existing hydro power reservoir pairs - while these operate as PHES units that at the same time maintain their autonomous hydro power use – it was decided to examine the long-term variation of the energy reservoirs for all of Greece's hydroelectric power plants[98].

As can be seen in Figure 5.2, the long-term minimum energy reserve during 2003-2008 was approximately 1/3 of the maximum. Based on that, the upper use limit of the lower reservoirs was taken equal to 25% of the maximum capacity, which ensures that the operational characteristics of the existing hydroelectric power plants are maintained. Hence, the upper limit of the storage capacity of the hybrid solutions examined is taken equal to 10 GWh.

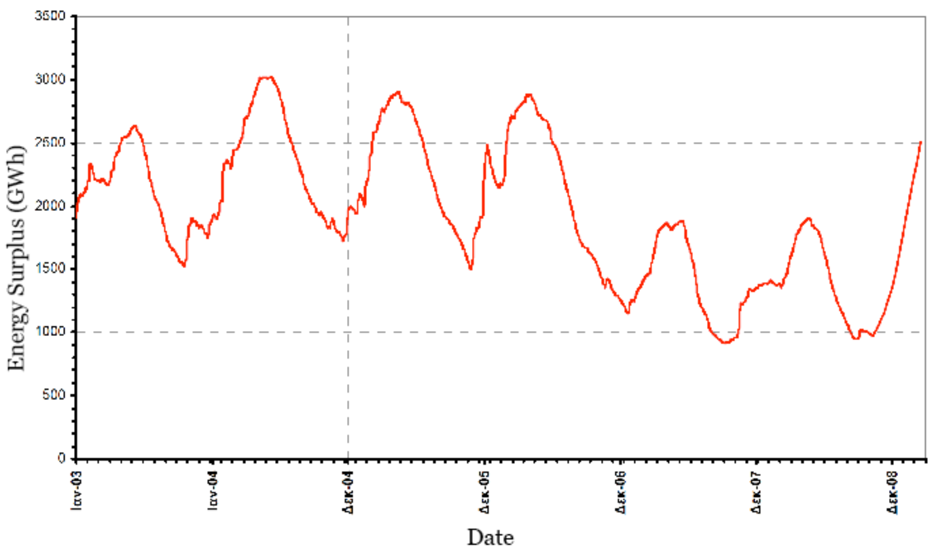


Figure 5.2. Hydroelectric plants energy reserve variation (2003-2008)[98]

Finally, the efficiency of PHES units was assumed constant at 75% and that of hydro turbines equal to 85%, resulting to a total efficiency of 63.75% for the load-unload cycle. This efficiency rate is considered rather low, taking in this way into account the possibility of an off-design operation of the systems.

To examine the proposed alternative solution to the construction of Ptolemaida V, a thorough methodology was developed, based on building up an analytical computational code for the energy simulation of RES-PHES hybrid schemes. The energy results of this computational code are then used in the economic evaluation of the suggested solution and the presentation of the optimal RES-PHES hybrid schemes. The main steps of the computational code and a description of its operation are presented in Annex I.

---

[98] Nikos Mamasis and Ioannis Stefanakos. (2010). Introduction to Energy Technology. Hydroelectric Power. Water Resources and Environment Sector, National Technical University of Athens, Athens 2010

Table 5.1: Existing, in-series hydro power plants with a PHES operational potential[97]

Upper-Lower Reservoir	Pournari II **- Pournari**	**Kastraki - Kremasta**	**Stratos - Kastraki**	**Asomata -Sfikia**	**Ag. Varvara - Asomata**	**Temenos - Planatovrisi**	**Platanovrisi - Thisavros**
Pumping Power (MW)	40.2	135.3	116.6	22.4	11	21.8	50.4
Dam Height (m)	87	165	96	82	52	95	172
Usable Height (m)	68	108.3	71.54	62	40	70	130
Usable / Dam	0.78	0.65	0.74	0.75	0.76	0.73	0.75
Upper Reservoir (Mm^3)	303	2,800	53	18	10	57	565
Lower Reservoir (Mm^3)	4	53	11	10	3	6	57
Hydro Power (Upper - MW)	100	109.3	80	105	54	58	128
Number of HP Plants	3	4	4	3	2	2	3
Total Hydro Power	300	437.2	320	315	108	116	384
Minimum Power (MW)	50	54.65	40	52.5	27	29	64
Maximum Storage Capacity (GWh)	**0.741**	**15.641**	**2.144**	**1.689**	**0.327**	**1.144**	**20.192**

5.2 Energy Analysis

First of all, as can be seen in Figure 5.3 there are many combinations of wind, PV and storage capacity that adequately meet the Ptolemaida V load within the specified range of values (wind and PV capacities up to 5 GW and storage capacity up to 10 GWh). In order to meet 100% of the Ptolemaida V load, at least 4 GW of wind capacity are needed to keep the storage capacity under 10 GWh, which corresponds to 25% of the maximum load for all the pairs of hydroelectric units examined. On the contrary, should almost full coverage be considered acceptable (95%), the desired outcome can be achieved at even lower wind capacity rates.

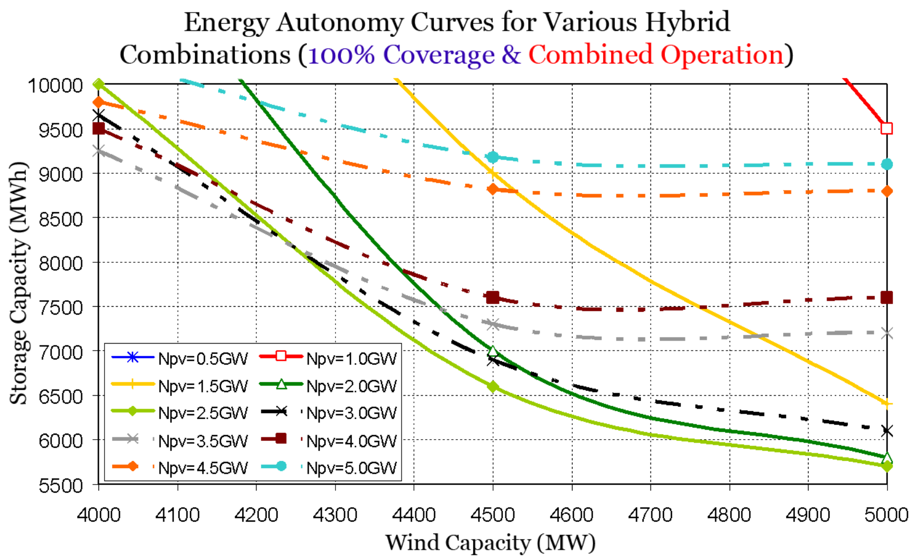
It is important to note the difference between the two cases under examination, i.e. full (100%) and almost full (95%) coverage, with regards to the storage capacity required. More specifically, adopting the almost full coverage scenario translates to smaller needs in energy storage, with the difference compared to full coverage becoming even more evident in the region of smaller overall values of installed RES capacity. For example, in order to meet a 100% demand, a combination of 4 GW wind and 2.5 GW PV requires approximately 10 GWh of storage capacity, whereas meeting a 95% demand requires only 1 GWh.

It is also noted that for a given PV capacity, increasing wind capacity results to a reduction in the required storage capacity up to a point, beyond which the curves become almost asymptotic[99]. That indicates a continuous increase in RES production surplus, i.e. the energy that remains once the equivalent base load of Ptolemaida V has been met. This surplus, regarded as intermittent and therefore subject to rejection by the NIS (see Annex I), can be reduced if the base load needs increase beyond those of Ptolemaida V, under of course the condition of a further increase in storage capacity.

Of particular interest is the effect of PV capacity on the form of the curves, especially in the case of meeting 100% of the Ptolemaida V base load. For low PV capacities, in the region below 2.5 GW, an increase in PV capacity reduces the storage capacity required (for a given wind capacity), which is mainly due to the complementarity between wind and PV electricity generation, as was presented in Chapter 2 (Figure 2.6 και Figure 2.7). So, for a given 4.4 GW and 1.5 GW of wind and PV capacities respectively, the required storage capacity reaches approximately the upper limit of 10 GWh, while for the same wind capacity and 2.5 GW PV capacity (which is almost the actual installed PV capacity today), the energy storage requirements drop to approximately 7 GWh.

However, for higher PV capacity values and under the requirement of full coverage (100%) of the Ptolemaida V load, this behaviour is reversed. Hence, a further increase in PV capacity (assuming wind capacity remains the same) will also require an increase in storage capacity, due to the subsequent increase in RES production at midday. This behaviour is explained by the fact that high PV capacities shift the energy production of HP to night hours, creating thus a need for longer load-unload cycles and hence larger storage capacities. On the contrary, for smaller PV shares the frequency and the length of load-unload cycles will also drop, thus leading to reduced storage needs.

[99] i.e. small variations in the Y-axis for wide range of values on the X-axis



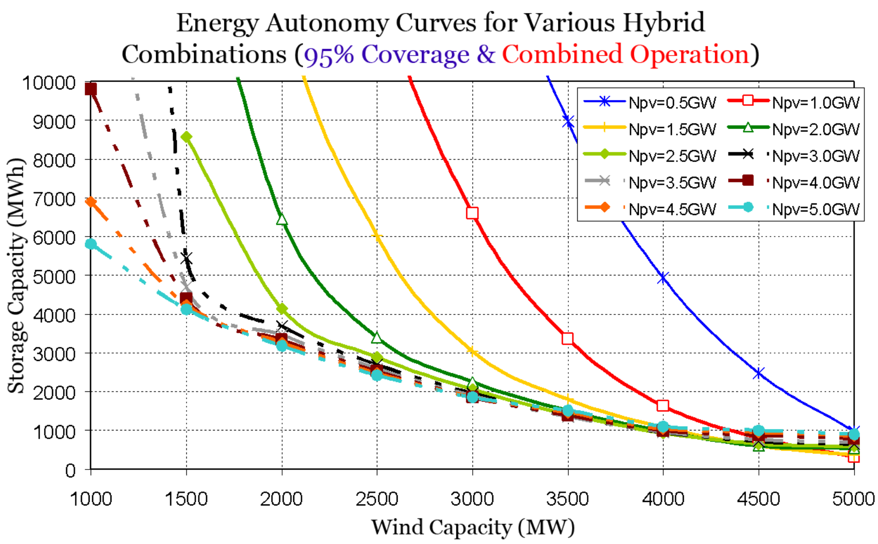


Figure 5.3. Energy autonomous hybrid combinations – Achieving a 100% and 95% base load coverage for minimum storage capacity (upper threshold 10 GWh).

The pumping capacity that corresponds to the above hybrid combinations in order to meet 100% of the Ptolemaida V load, is given in Figure 5.4, for 3 representative wind capacity values equal to or exceeding 4 GW. As is evident, the required pumping capacity ranges between 50 and 300 MW. One should also note that, according to a recent study[97], the potential arising from converting existing HP plants to PHES can reach up to 400 MW. Therefore, the hybrid combinations resulting from the energy analysis are realistically feasible.

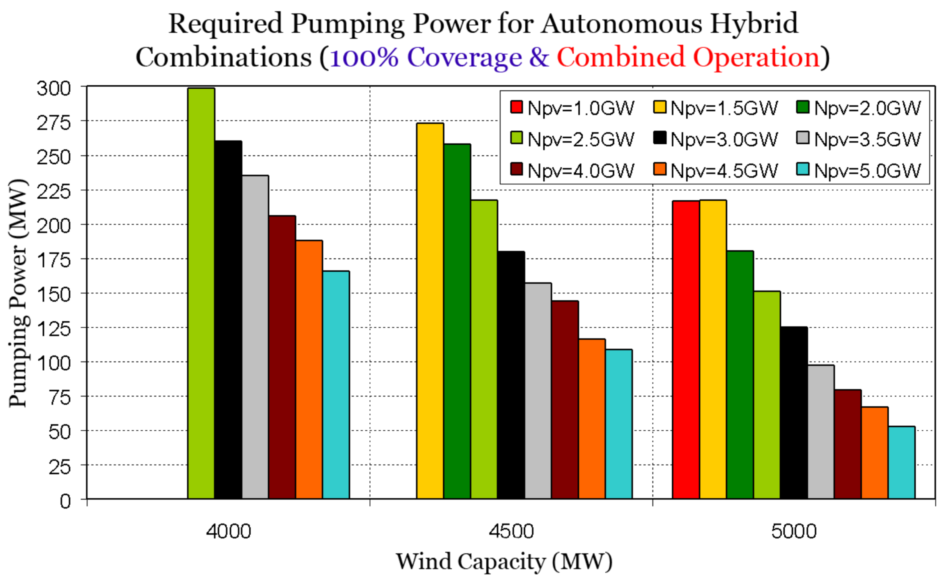


Figure 5.4. Required pumping power of energy autonomous hybrid combinations – Achieving 100% base load coverage for minimum storage capacity (upper threshold 10 GWh).

5.3. Economic assessment

Taking into account the current cost of new wind farms and PV parks (also used in Chapter 3), the installation cost and the LCOE of the hybrid combinations that resulted from the above energy analysis were calculated in Present Values. A low-cost and a high-cost scenario were examined, whose main parameters are described in Table 5.2. As far as the management of RES surplus rejected by the NIS is concerned, it was decided to use year 2020 as a reference scenario, on the basis of an annual power increase of 2.3% and the current minimum load of 4 GW.

It should be stressed that, as the construction of new reservoirs is not required in the under investigation HP to PHES units conversion, the cost is significantly reduced, and involves mostly the pumping units and water distribution pipes between the reservoirs. This was taken equal to 520€/kW of pumping capacity[97].

Table 5.2: Economic parameters for the evaluation of the proposed solution

Parameter	High Cost Scenario	Low Cost Scenario
Weighted average cost of wind installation (€/kW)	1,500	1,000
Weighted average cost of PV installation (€/kW)	1,650	960
Weighted average cost for converting HP to PHES units (€/kW)	520	520
Average annual maintenance coefficient (% installation cost)	2%	2%
Project lifetime (years)	30	30
Average annual inflation	2%	2%
Average annual discount rate	7%	7%

Figure 5.5Figure 5.5 and Figure 5.6 show the installation cost curves for both the high-cost (Figure 5.5) and low-cost scenarios (Figure 5.6), for covering 100% and 95% of the base-load equivalent of Ptolemaida V. These curves correspond to the hybrid solutions presented in Figure 5.3, and estimate the overall RES installation cost (without excluding the PV and wind capacities already installed). It is noted that, in the high cost scenario, the hybrid solutions that manage to meet 100% of the Ptolemaida V load have an initial investment cost of €9-16bn, while for an

almost full coverage (95%) the range lies between €6-16bn. The initial investment cost of the low-cost scenario is much lower, ranging between €6-10bn in the case of full coverage and €4-10bn in the case of almost full coverage. It should also be noted that the total investment cost would be even lower if storage capacities could exceed 10 GWh. However, this restriction results to a need for higher RES capacity in order to meet the base load, increasing thus the overall cost, as the unit installation cost of wind and PV has a greater influence than that of the specific PHES units.

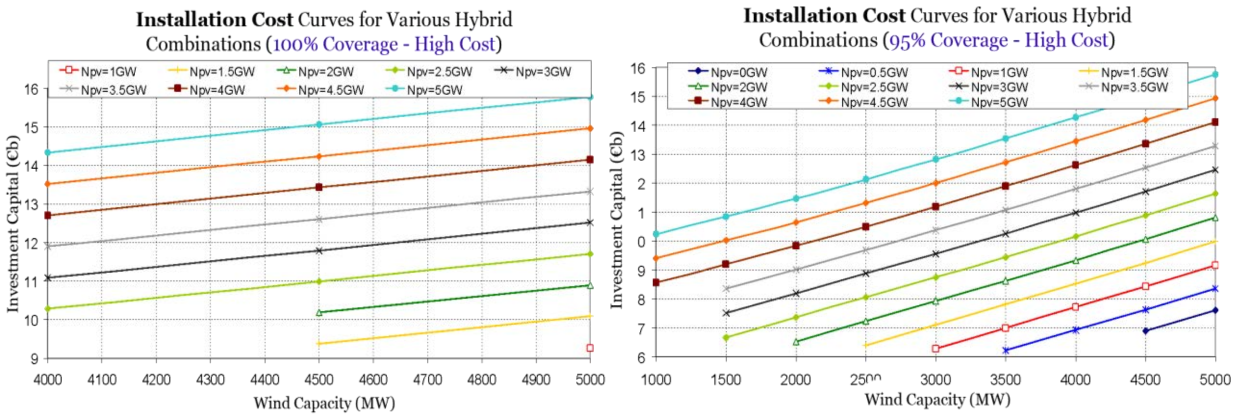


Figure 5.5. High Cost Scenario: Installation cost of energy autonomous hybrid solutions of a ≤10GWh storage capacity, achieving a 100% and 95% base load coverage.

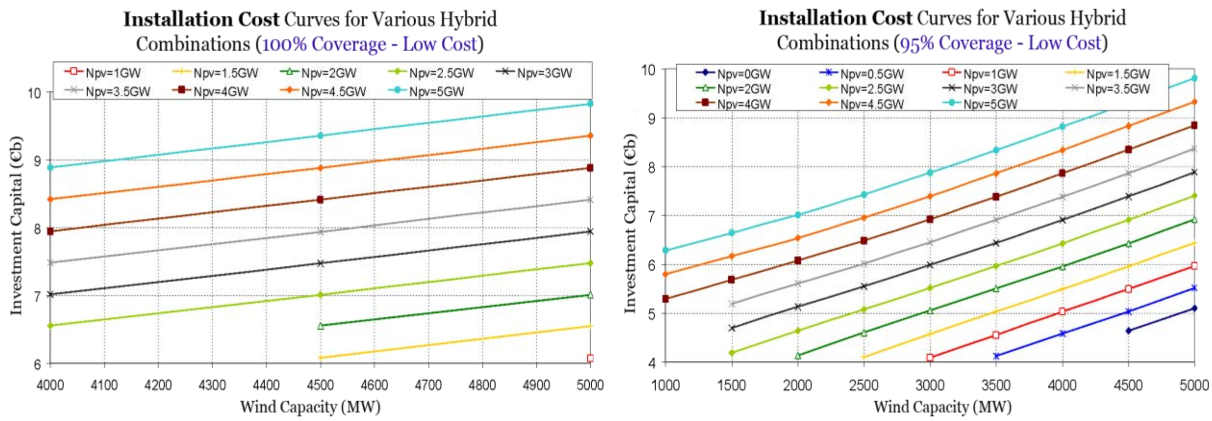


Figure 5.6. Low Cost Scenario: Installation cost of energy autonomous hybrid solutions of a ≤10GWh storage capacity, achieving a 100% and 95% base load coverage.

The share of PHES in the total cost is relatively low. As can be seen in Figure 5.7, it reaches a maximum of €500m (95% coverage and limited RES capacity), while the cost of many hybrid solutions remains below €100m (95% and 100% coverage and high-capacity RES). More specifically, the PHES installation cost ranges between 1% and 5% of the total required investment.

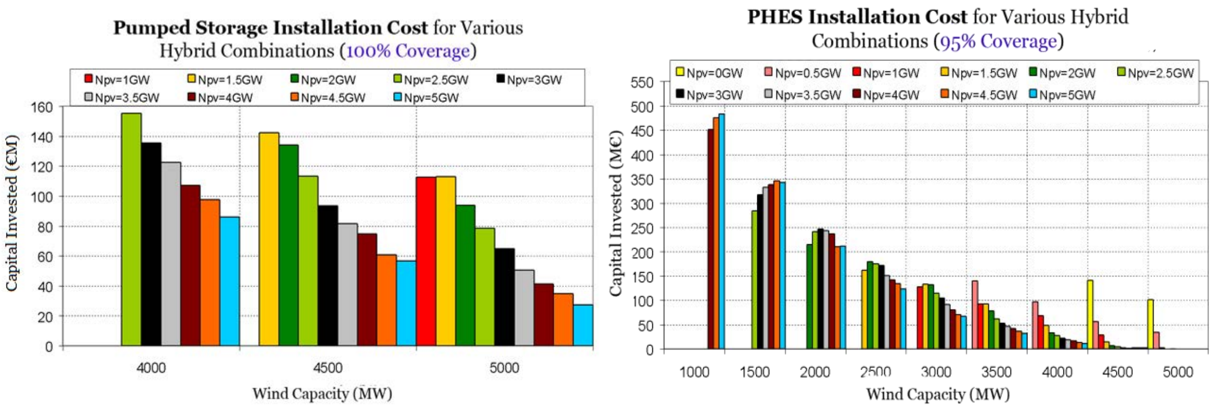


Figure 5.7. Pumped hydro energy storage installation cost of energy autonomous hybrid solutions – 100% (a) and 95% (b) attainment of base load coverage for minimum storage capacity (10 GWh upper threshold).

Using the data provided in Table 5.2, the LCOE was also calculated, for the hybrid solutions resulting from the energy analysis of the high (Figure 5.8) and low (Figure 5.9) cost scenarios, for both full and almost full coverage, assuming a rejection of RES electricity generation corresponding to a system's minimum load of 4 GW, a 2.3% annual increase rate of demand and 2020 as the reference year.

For a 100% coverage, the LCOE increases almost linearly with the increase in PV capacity. It is largely unaffected by the increase in wind power capacity, which is partly the result of the limited range (4 GW to 5 GW) of the hybrid solutions that manage a 100% coverage of the Ptolemaida V demand load.

In the high cost scenario, the resulting values range between ~75 €/MWh and ~105 €/MWh for 100% coverage, and ~70 €/MWh to ~135 €/MWh for 95% coverage. The wider range of LCOE in the 95% case is due to the existence of more hybrid solutions, especially in the region of restricted wind and increased PV power, with the curves in Figure 5.8b being asymptotic beyond 3 GW of wind power.

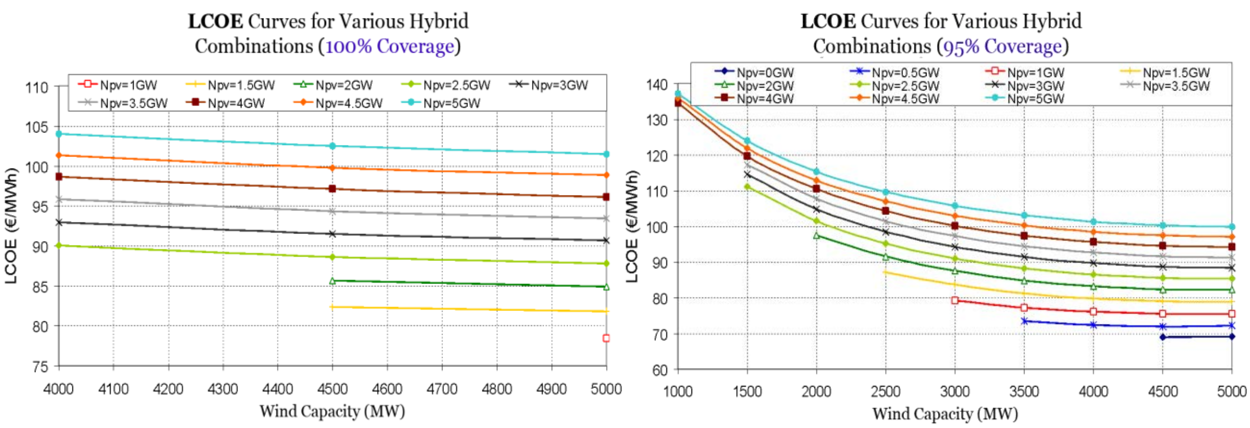


Figure 5.8. High cost scenario: LCOE of hybrid solutions – 100% (a) and 95% (b) attainment of base load coverage for a ≤10GWh storage capacity

In the case of the low cost scenario, there is an important shift in the fluctuation range of the LCOE to 50-65 €/MWh for 100% coverage (Figure 5.9a) and to 45-85€/MWh for 95% coverage

(Figure 5.9b), while the quantitative qualities of the curves are similar to those of the high cost scenario.

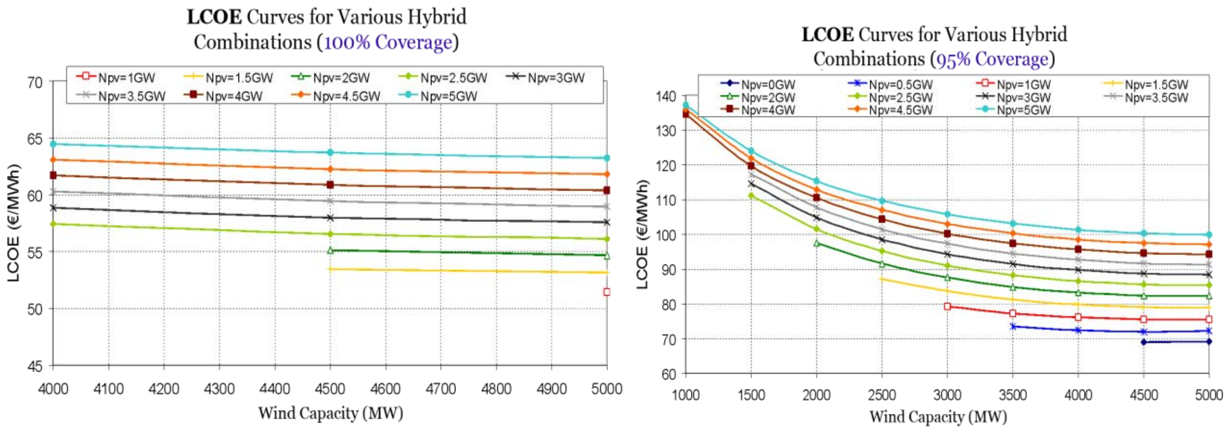


Figure 5.9. Low cost scenario: LCOE of energy autonomous hybrid solutions – 100% (a) and 95% (b) attainment of base load coverage for a ≤10GWh storage capacity

The same analysis was also performed for the extreme scenario of a full rejection of the RES surplus by the NIS. The corresponding fluctuation range shifts to areas of increased values, the minimum LCOE of 100% coverage being ~140 €/MWh (low cost scenario) and ~210 €/MWh (high cost scenario), and ~90 €/MWh (low cost scenario) and ~140 €/MWh (high cost scenario) in the case of 95% coverage.

5.4. Comparison between hybrid solutions and Ptolemaida V

The sensitivity analysis performed in Chapter 3 demonstrated that the LCOE of Ptolemaida V ranges between 96.47 €/MWh and 162.45 €/MWh. In point of fact, the lower limit corresponds to a larger capacity factor for the lignite plant than the one described in the EIA (90% vs 80%), which leads to a lower LCOE (Figure 3.4). Figure 5.10 presents a comparison between the LCOE of RES-PHES hybrid solutions that resulted from the above energy analysis (Figure 5.3), and that of Ptolemaida V.

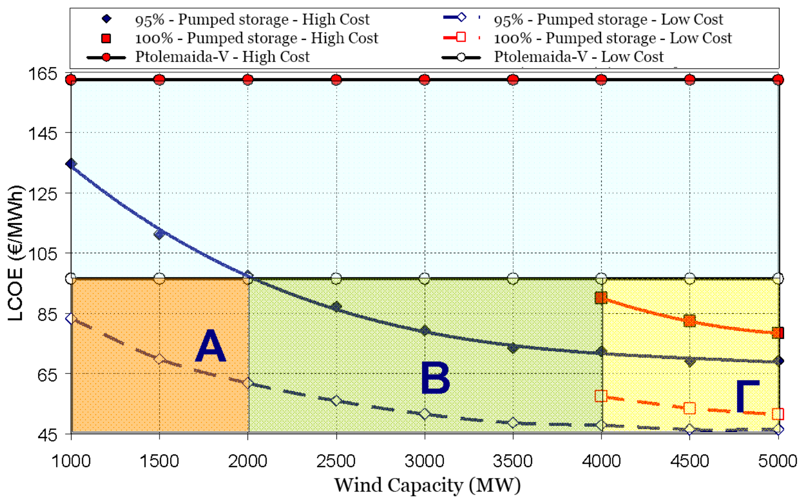


Figure 5.10. LCOE of energy autonomous hybrid solutions - 100% (a) and 95% (b) attainment of base load coverage for storage capacity ≤10GWh

A clearer view of the hybrid combinations that correspond to the solutions presented in Figure 5.10 is given in Figure 5.11, which links the required PHES capacity to the characteristics of the

RES power mix (and more precisely the share of wind capacity – with regards to the maximum 5 GW capacity – compared to the total RES capacity).

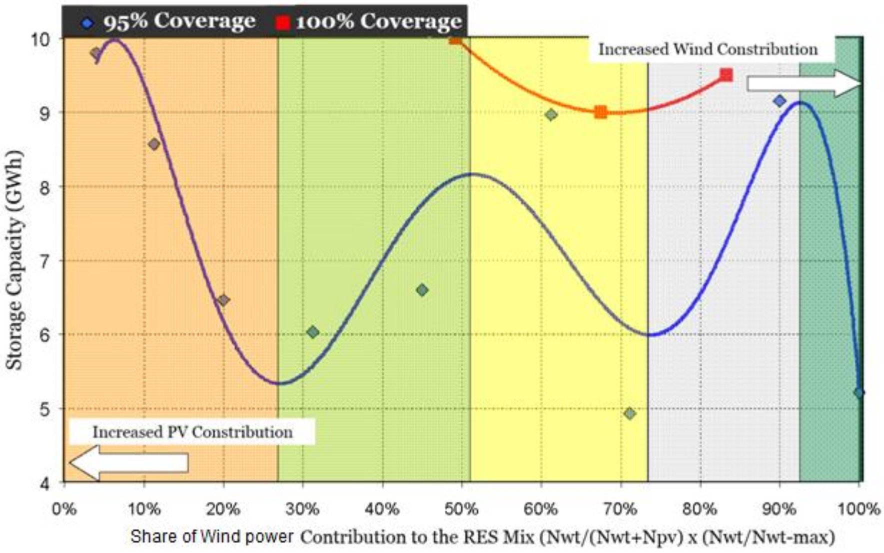


Figure 5.11. Required pumped hydro energy storage capacity of the hybrid solutions of minimum LCOE versus the differentiation of the RES power mix.

The two figures show hybrid combinations that achieve 100% coverage of the Ptolemaida V load, with the LCOE below the low limit of the equivalent for the new lignite plant. The number of economically competitive solutions further increases if almost full coverage (95%) is considered acceptable, or/and if the higher LCOE of Ptolemaida V (according to the analysis) is taken into account. Table 5.3 presents all the main characteristics of the optimal hybrid solutions of minimal cost that achieve full and almost full coverage of the Ptolemaida V load, along with the LCOE of the high and low cost scenarios, which have an LCOE below the low limit of the respective one for Ptolemaida V.

Table 5.3: Hybrid solutions that are economically competitive with Ptolemaida V

Wind Capacity (MW)	PV Capacity (MW)	Storage Capacity (MWh)	LCOE (€/MWh) (High Cost)	LCOE (€/MWh) (Low Cost)
100% Coverage				
4,000	2,500	10,000	90.06	57.43
4,500	1,500	9,000	82.35	53.47
5,000	1,000	9,500	78.44	51.42
95% Coverage				
2,000	2,000	6,460	97.50	83.30
2,500	1,500	6,030	87.21	69.86
3,000	1,000	6,600	79.27	61.88
3,500	500	8,970	73.48	56.01
4,000	500	4,930	72.43	51.62
4,500	0	9,150	69.08	48.71
5,000	0	5,210	69.25	47.90

It should be emphasised that the above results were calculated assuming a system's minimum load of approximately 4 GW. Achieving lower minimum loads is possible by withdrawing aged lignite plants, which will further decrease the LCOE of hybrid combinations, as a result of a reduction in the share of rejected RES surplus.

It therefore becomes clear that the conversion of existing PPC HP units to PHES units, and their use for storing the energy produced by wind and PV power stations is not only technically feasible, but also leads to LCOEs that are significantly lower than those of the new lignite plant. In addition, due to the assumptions made regarding the maximum storage capacity available, it is believed that the proposed operation of the pumped-units will not hinder the current operation of the hydroelectric plants.

It is worth noting that the minimum LCOE of Ptolemaida V (96.47 €/MWh) that was used in its comparison with the hybrid solutions, corresponds to an even greater capacity factor (90%) than the one aimed at by the EIA (80%). If the estimates resulting from an older study by WWF Greece[20] regarding the drop in operating hours of the new lignite plant as a result of RES penetration are confirmed, then the comparison will favour Ptolemaida V even less.

6. SMALL SCALE ALTERNATIVES: NET METERING OR AUTONOMOUS PV

Chapter 5 demonstrated the potential for meeting the Ptolemaida V demand by combining PHES and large-scale wind and PV stations. According to the Energy Impact Assesment of the new lignite plant[54], Ptolemaida V will operate for 7,000 hours per annum and provide 4.16 TWh of energy to the network. However, as was revealed in a previous study by WWF Greece[20], the demand that the new lignite plant will be asked to meet might turn out to be significantly less for a number of reasons, the most important being the negative development of CO_2 emissions allowances costs and the increase in the share of large-scale RES in Greece's energy mix.

More than that though, crucial to the reduction of the electricity demand from large, central, conventional power plants such as Ptolemaida V, will be the changes in the electricity model at a household level, towards decentralisation and a gradual independence from the main power grid, thus transforming the traditional consumer to a producer of the energy he consumes (prosumer). A major factor in this transition is the ongoing technological revolution in the PV sector, as well as the one in the battery technology sector, which, according to many experts, is fast approaching.

The important growth of PV at a global level, mainly due to the support offered through Feed-in Tariff schemes (FiTs), has laid the foundations and has created the economies of scale necessary in order for the technology to become commercially competitive. The analysis in Chapter 3 revealed that to a large extent this is the case for Greece, too. With regards to small-scale PV in particular, and as a result of the FiT scheme, there were 374 MW of small PV up to 10 KW (up to 5 KW in the islands) installed on 41,217 rooftops[27] by the end of 2013.

6.1 Description of the alternatives

At a global scale, the policies to promote the development of small-scale PV are nowadays moving beyond FiTs, and mainly towards net-metering. That involves offsetting PV production against the energy consumed in a specific installation, within a given time frame (day, month, year). While the FiT scheme offers compensation to the producer for the energy supplied to the grid, and hence encourages the installation of the highest possible capacity, the rationale behind net-metering is different: as the compensation offered to the producer for the energy surplus fed to the grid is either zero or very small, the main aim of the scheme is to cover as much of the prosumer's demand as possible, rather than to maximize the energy supplied to the grid. To that end, net metering results to smaller PV sizes compared to the FiT scheme.

Historically speaking, the net-metering scheme derives from the USA, where it was used as a direct measure for supporting and promoting RES technologies, by allowing the producers to 'store' the renewable energy they produced back to the grid. Today, the scheme is applied with variations in most USA states[100], while since 2005 a law is already in place that requires all public electric utilities to make available upon request net metering to their customers.

Some European countries such as Belgium, Denmark and the Netherlands have already adopted the net-metering scheme, while others rely on more hybrid solutions. More specifically, as of 2011 Germany offers incentives through FiTs for self-consumed electricity. In case the share of self-consumption exceeds 30%, the guaranteed price increases. A similar system is in place in Italy as of the last quarter of 2012. Spain adopted the self-consumption scheme in 2011, while discussions are in place about implementing net-metering, without however offering full exemption from the costs associated with the operation and maintenance of the network. The UK has in place a self-consumption scheme with FiTs, unlike France, where a concrete support scheme is yet to be adopted.

[100] DSIRE Solar web page.
http://www.dsireusa.org/incentives/index.cfm?EE=1&RE=1&SPV=0&ST=0&searchtype=Net&sh=1

Recently, and albeit somewhat late, a Ministerial Decree on net-metering was also issued in Greece[101]. The energy offset is annual and no compensation is offered to the prosumer for any energy surplus produced by the PV throughout a year. In addition, and despite the opposing criticism made during consultation[102], the prosumer will be obliged to pay for Services of General Interest (SGI) to the electricity provider, based on the total amount of energy consumed, including PV-produced energy. As far as the RES levy is concerned, the initial Ministerial Decree plan issued for consultation called for a similar approach to that of the SGI. In light, however, of the criticism that followed –in an amendment issued as part of the new 4314/2014 forest law – it was decided that prosumers should pay the RES levy only for the amount of electricity that they receive from the Grid/System. This amendment does not eliminate the RES levy that burdens prosumers, but rather limits it to the amount of PV electricity generated outside consumption. Network transportation and distribution charges are calculated in a similar way to that of the RES levy.

In remote areas with no grid, the operation of PV requires the use of batteries that store the energy surplus left unconsumed, offering it back during hours with no sunshine. However, as battery technology develops and its cost drops, small-scale PV with battery storage can become economically competitive with grid-offered electricity.

The next part of the chapter offers an economic evaluation of these two alternatives (net metering and PV with battery storage) for the case of Greece, with the aim of evaluating their potential to contribute to the transformation of the electricity production model at household level in the direction of decentralization and gradual independence from large, central plants such as Ptolemaida V.

6.2. Economic evaluation of self-generation with net metering

There were two basic implementation scenarios of this mechanism examined. The first one ('MD') coincides with the recent Ministerial Decree, whose main principles were described earlier. Based on the assessments made by various bodies – including WWF Greece[103] - during consultation on the initial MD plan, a second scenario was examined ('Alternative Plan') where it was assumed that the prosumer attributes SGI and RES levy only for the amount of energy drawn from the grid within a year, deducting thus from these charges the electricity produced by PV during the same period.

Therefore, in the first scenario ('MD'), the prosumer is exempt from costs related to the use of PV for covering his energy needs that include, apart from the cost of the energy generated, the network-related costs (transportation and distribution) that correspond to its non-use due to the simultaneous coverage of household consumption through PV, the Excise Duty (ED), any additional charges, the special duty of law 2093/92 and the RES levy share that corresponds to the simultaneous coverage of household consumption through PV.

In the second scenario ('Alternative Plan'), apart from the charges mentioned above, the prosumer also avoids the amount of SGI that corresponds to the energy produced by PV, as well as the remaining part of RES levy that corresponds to the non-simultaneous coverage of household consumption by PV. It should be noted that none of the scenarios excludes fixed charges or network charges related to the energy that the prosumer draws from the grid when his needs are not covered by PV production, and that all calculations include VAT.

---

[101] Minister of Environment, Energy and Climate Change. (2014, December). R/N RESEL/D/P1/ec.24461 "Installation of RES units by prosumers using net metering – implementation of article 14A, law 3468/2006", http://www.ypeka.gr/LinkClick.aspx?fileticket=9HB%2fezdtZvE%3d&tabid=785&language=el-GR

[102] RAE Public Consultation as part of implementing article 14A of law 3468/2006, regarding RES prosumers using net metering, http://www.rae.gr/categories_new/about_rae/activity/global_consultation/current/300714.csp

[103] Assessment of WWF Greece on the planned Ministerial Decree regarding net metering. (2014, August). http://www.wwf.gr/images/pdfs/WWF_net_metering_.pdf

In order to estimate the right amount of grid charges (as well as the RES levy, in the MD scenario) that are avoided in each case by the prosumer, it's crucial to be aware of the so-called coincidence factor, which is defined as the ratio of the electricity consumed that results from simultaneously produced PV electricity, by the total energy consumed. For this purpose, the typical household power load demand, as this is given by the CRES[104] for the period between 15 September and 15 December 2009, was normalised to an annual basis.

The normalisation was done based on the total system load and the adjustment of consumption to the annual levels examined. Using the average annual PV capacity and load curves given in Figure 6. 1, it is derived that the coincidence factor is approximately 39%. This value was used as input data in the calculations.

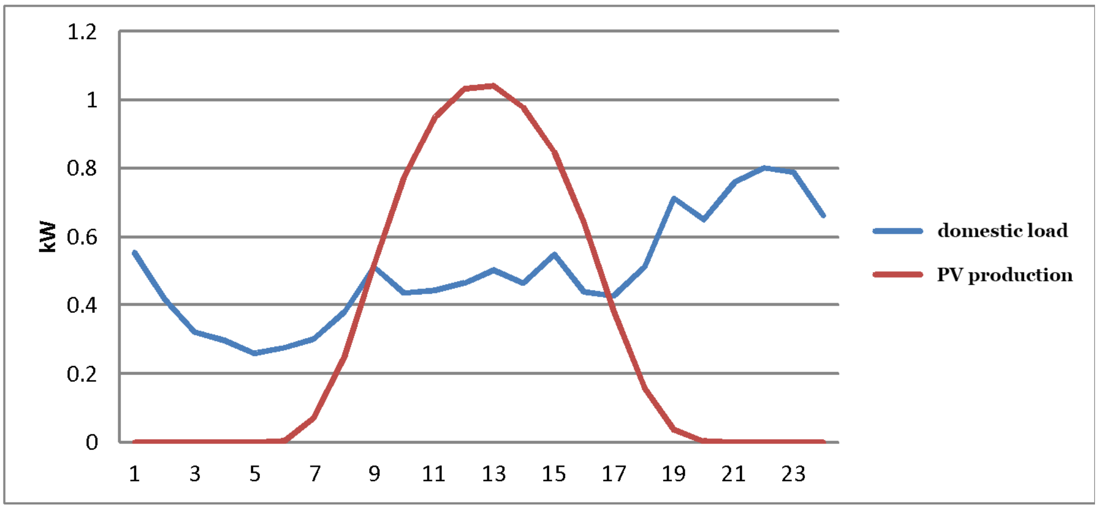


Figure 6. 1. Hourly average household load (4 MWh energy) and hourly average PV production (2kW power)

At a first stage, a comparative economic evaluation of the aformentioned scenarios was performed for low (4,000 KWh) and high (9,045 KWh) annual household consumption. The energy yield of PV (KWh/KWp), including all associated losses, was taken from the PV Geographical System of the EU (PVGIS)[105] for the Attica region, while the unit installation cost was taken from the current market prices in Greece[106]. It's important to note that the PV system's capacity was chosen so as to cover the corresponding annual energy consumption. In addition, the connection costs have been included in the installation costs, and an annual reduction in PV efficiency was assumed in the calculations[107]. Finally, the various elements of the avoided cost were taken from current PPC invoices[108]. Table 6.1 presents all the numeric values used in the calculations, for the annual consumption in both cases.

Table 6.1: Basic data used in net metering analysis

Annual Consumption (KWh)	4,000	9,045
Photovoltaic Energy Yield (KWh/KWp)	1,351	1,351
PV Cost (€/kW) (inc. VAT)	2,030	1,470
Connection Cost (€)	1,000	1,000
Average annual drop in efficiency (%)	0,5	0,5

[104] PEPESEC PROJECT, Energy planning for sustainable communities, «Indicative results of the electricity measuring campaign in the Municipality of Amaroussion (CRES)», http://www.cres.gr/pepesec/apotelesmata_uk.html
[105] Photovoltaic Geographical Information System (PVGIS), http://re.jrc.ec.europa.eu/pvgis/
[106] http://www.ecotopten.gr/index.php?page=9-w
[107] Hellenic Association of Photovoltaic Companies (HELAPCO). (2013, November). "Proposals for the optimal implementation of net-metering", http://helapco.gr/wp-content/uploads/HELAPCO_Net_Metering_25Nov2013.pdf
[108] PPC household invoices, http://www.dei.gr/el/eksupiretisi-pelatwn/oikiakoi-pelates/timologia

Lifespan (years)	25	25
Consumer Price Indicator (%)	2	2
Annual Increase in selling price (%)	2	2
Daytime energy charge (€/kWh)	0.0946	0.10252
Nighttime energy charge (€/kWh)	0.0661	0.0661
Daytime to nighttime consumption ratio	2/1	2/1
Regulated grid cost (€/KWh)	0.02703	0.02703
SGI charges for daytime consumption (€/KWh)	0.00699	0.03987
SGI charges for nighttime consumption (€/KWh)	0.00889	0.00889
RES levy (€/KWh)	0.0263	0.0263
Excise Duty (€/KWh)	0.0022	0.0022
Other charges (€/KWh)	0.00046	0.00046
Excise Duty 5‰ law 2093/92 (€/KWh)	0.005	0.005

Table 6.2 summarizes the Internal Rate of Return (IRR) and the time required for the payback of the initial investment, while Figure 6.2 presents the cash flow for the two rates of annual consumption, for both scenarios.

Table 6.2: Economic analysis results for annual averages of 4,000 KWh and 9,045 KWh for the 'MD' and 'Alternative Plan' net metering scenarios

Annual Consumption (KWh)	PV Power (KW)	'MD' Scenario		'Alternative Plan' Scenario	
		Payback period (years)	IRR	Payback period (years)	IRR
4,000	3.1	15.38	4.04%	12.51	6.10%
9,045	6.8	9.72	8.92%	6.84	13.83%

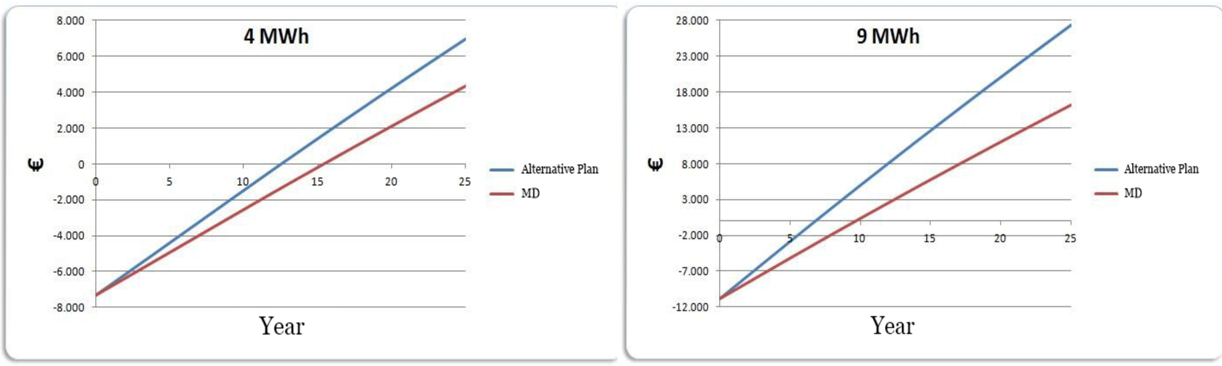


Figure 6.2. Avoided cost throughout a 25-year period resulting from the use of net metering in PV systems covering an annual consumption of 4 MWh (left) and 9 MWh (right)

It's interesting to note that higher consumption rates are defined by shorter paybacks as well as increased efficiency, as the avoided cost is significant and the unit installation cost is considerably lower. The combined effect of the SGI charges, on the total energy consumed and those of the RES levy on the non-concurrently produced part of the PV-generated energy, is significant as it increases the payback period by approximately 2.9 years for both the low and high annual consumptions. The financial gain of the prosumer by the end of the 25-year contract is significantly higher in the case of the alternative plan (€27,314 in the 'Alternative Plan' vs €16,149 in the 'MD' scenario for 9 MWh of annual consumption).

It was also decided to perform calculations within the 2,000-14,000 KWh range, in order to offer a clearer view of the effect that annual consumption has on the economic performance of the net metering mechanism in both scenarios. The 14,000 KWh upper limit of annual consumption for a household application corresponds to a 10 KW PV system with a 1,400 KWh/KWp yield, and can be realised in practice by an extensive use of electricity for heating during winter and/or combined with the use of electric vehicles in the future. The parameters used were those given in Table 6.1. To calculate the installation cost of the power corresponding to each of the annual consumption rates examined, linear interpolation for the market prices of various PV capacity values was performed. The results are presented in Figure 6.3.

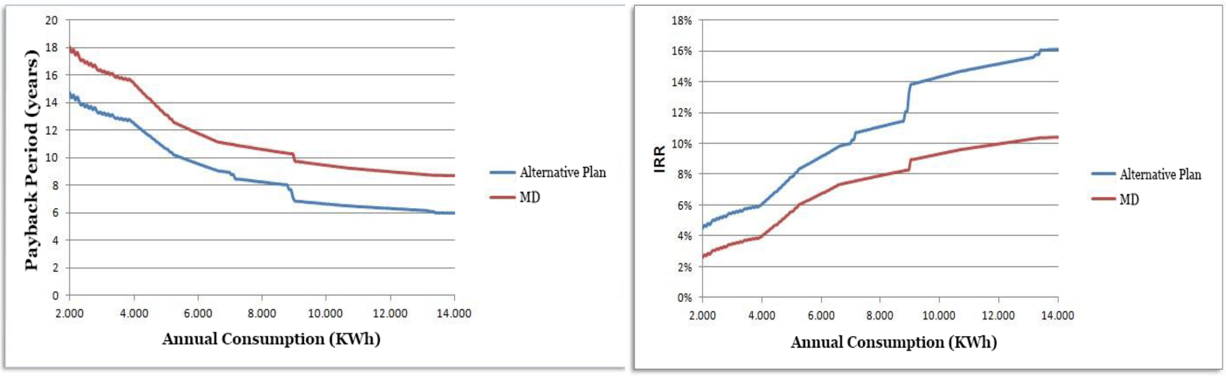


Figure 6.3. Payback period (left) and IRR (right) as a function of annual energy consumption for the 'MD' and 'Alternative Plan' scenarios

It was noted that, throughout the range of annual consumption values, the implementation of net metering in line with the MD scenario leads to paybacks prolonged by 2 – 3.4 years. Also notable is the expansion of the difference between the two scenarios, regarding the internal rate of return and the higher rates of annual consumption (exceeding approximately 9 MWh). This behaviour is mainly due to the fact that at higher consumption levels, the contribution of SGI increases. Hence, avoiding these charges in the 'Alternative Plan' affects more the IRR of higher annual consumption rates. The above highlight that applying the RES levy and SGI charges only to the energy that prosumers draw from the grid, and not to that produced by the PV system, will improve significantly the economics of net metering in Greece.

It's also interesting to observe the effect of geographical location on the economics of net metering. Using PVGIS[105] data for the average energy yield in various prefectures, Table 6.3 presents the results for regions in Greece that differ significantly in terms of insolation. Hence, a PV system required to meet the same energy demands would have an additional payback period of 1.7 years in Drama (northeastern Greece) compared to the islands of the Dodecanese, and a 2% lower IRR in the MD net metering implementation scenario. These discrepancies are due to the fact that regions of lower solar radiation require more PV capacity, the installation of which also translates to higher unit costs. These differences become even more significant as far as the IRR is concerned, reaching up to 2.5% according to the 'Alternative Plan'.

Table 6.3: Payback period and IRR for different regions of Greece (9,045 KWh annual consumption)

Prefecture	Average yield (KWh/KWp)	PV capacity (KW)	'MD' scenario		'Alternative Plan' scenario	
			Payback Period (years)	IRR	Payback Period (years)	IRR
Drama	1,108	8.3	11.22	7.24%	7.89	11.70%
Thessaloniki	1,168	7.8	10.79	7.68%	7.58	12.26%
Kozani	1,238	7.4	10.35	8.17%	7.28	12.87%
Dodecanese	1,390	6.6	9.52	9.18%	6.70	14.16%

An important factor of uncertainty in the economic assessment of net metering is the development of the sale price of electricity. European Commission estimates[109] leave no doubt

[109] Ευρωπαϊκή Επιτροπή (2014, 17 March). «Energy prices and costs report, *Accompanying the document,* «COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN, PARLIAMENT, THE COUNCIL, THE

that the price will go up, mainly due to the expected increase in the cost of fossil fuels, the increase in the CO_2 emissions costs of the European Union Emissions Trading System (EU ETS), as well as due to the investments required in terms of energy infrastructure.

Especially in Greece, the interconnection projects for the Cyclades islands[110] and Crete[111], and the required upgrade works in order for the existing lignite plants to meet the emission limit values described in European legislation (Directive 2010/75/EU), are expected to have a significant effect on increasing the sale price of grid electricity. The aid offered to medium and high voltage clients also results to indirect increases in household bills. Quite significantly, between June 2013 and May 2014, the low Voltage RES levy for household use showed an increase of 176% while the medium and high Voltage RES levy was reduced by 70% and 37% respectively[112].

In order to make a preliminary assessment of this effect on the economics of net metering, Tab;e 6.4 presents the impact of different electricity price increase rates on the resulting IRR, for the same annual consumption. All other parameters remain the same as the ones presented in Table 6.1. The increase in the price of electricity has a noticeable effect on both net metering implementation scenarios. In the MD case, a 5% increase speeds up the payback period by approximately 2 years, compared to a smaller increase of around 1%. Should the prosumer be relieved from paying SGI and RES levy on his entire annual consumption, a 5% increase in the sale price of electricity will make the PV investment even more rewarding by 4.5% compared to a 1% increase, while the payback period will be reduced by approximately 1 year.

Table 6.4: Effect of the different electricity price increases, for a 9,045 KWh annual consumption

% Annual increase in retail price	'MD' Scenario		'Alternative Plan' Scenario	
	Payback period (years)	IRR	Payback period (years)	IRR
1%	10.28	7.85%	7.12	12.72%
2%	9.72	8.92%	6.84	13.83%
3%	9.24	9.99%	6.59	14.95%
4%	8.81	11.06%	6.36	16.06%
5%	8.44	12.13%	6.15	17.18%

It should be noted that the comparative results of the two net metering implementation scenarios presented in Table 6.4 are expected to differ significantly in case the percentage increase in the retail price of electricity applies only to specific charge categories, such as e.g. the SGI or the RES levy. SGI charges have remained constant over the past years, but are expected to increase soon, in order to cover the deficit of the associated special account, due to the increase in the cost of electricity production in the non-interconnected network in 2012 and 2013[113]. The RES levy has increased significantly over the past years, as between June 2013 – May 2014 alone, the price increase for household use reached 176%[112].

It thus becomes clear from the analysis presented above that there is a great potential for the development of small-scale PV systems through the implementation of the net metering mechanism in Greece. Should the Ministerial Decree shift towards the direction of the proposed 'Alternative Plan', that potential could in fact be enhanced even further. It is also important to highlight that the projected development of small-scale PV will not bear a burden on the LAGIE

EUROPEAN ECONOMIC AND SOCIAL, COMMITTEE AND THE COMMITTEE OF THE REGIONS»: Energy prices and costs in Europe». http://ec.europa.eu/energy/doc/2030/20140122_swd_prices.pdf

110 IPTO, Press Release. (2014, 10 September). "Signature of agreement for the electronic interconnection of Cyclades with the Mainland System" www.admie.gr/anakoinoseis/deltia-typoy/deltio-typoy/article/1581/

111 RAE. (2011, April). "Study on the development of the Electric System of Crete – Interconnection with the Mainland System: Extensive Summary" http://www.admie.gr/fileadmin/user_upload/Files/study/MELETI_DIASYNDESIS_TIS_KRITIS_EKTENIS_PERILIPSI.pdf

112 WWF Greece (2014, September). "Implementation commitments – The environmental legislation in Greece" Annual Report http://wwf.gr/images/pdfs/WWF-NOMOreport-2014-FINAL.pdf

113 RAE. Approval of the compensation for covering General Public Service (SGI) charges for 2012 and 2013, http://www.rae.gr/site/file/categories_new/about_rae/actions/decision/2014/2014_A0356?p=files&i=0

RES account, since the net metering mechanism is fundamentally different from the guaranteed prices (FiT) scheme.

6.3. Economic evaluation of photovoltaics with battery storage

As is evident from the aforementioned results, net metering offers great potential as far as developing small-scale photovoltaics for meeting household electricity demands, particularly in case the Ministerial Decree shifts in the future towards the direction of the 'Alternative Plan'. However, for such a mechanism to be applied, the prosumer needs to remain connected to the grid, as PV energy production and consumption don't occur simultaneously. In addition, according to the Ministerial Decree, the prosumer is burdened with SGI charges for all the energy consumed, as well as with network service charges and the RES levy based on the energy drawn from the grid, without an annual offset taken into account. The uncertainty associated with the price development of these charges and the general cost of electricity can be overcome through the use of fully stand-alone systems. Such systems consist of photovoltaics and a battery array that accumulates excess energy, handing it back during the hours of the day without sunshine.

The main performance characteristics of batteries comprise their voltage, capacity, efficiency, depth of discharge and the number of charge-discharge cycles. Their capacity (given in Ah) multiplied by voltage (V) gives the energy stored in Wh, while the efficiency rate defines the energy losses during a charge-discharge cycle. In the interest of increasing their lifespan, only a share of the stored energy is used (rather than 100%), i.e. the batteries discharge up to a certain depth (depth of discharge). The charge-discharge cycles, along with the depth of discharge at which the battery operates, define its typical lifespan, in other words the time required for its actual capacity to drop to 80% of its nominal value. Therefore, a battery that goes through deep discharges has a significantly shorter lifespan compared to one that operates at a lower depth of discharge.

To this day, stand-alone systems are almost exclusively used for covering electricity demands in regions that are not connected to the grid. The rechargeable batteries most commonly used with PVs are of sulfuric/lead acid, open or closed type (GEL, AGM, VRLA). Despite the fact that lead-acid batteries are nowadays cheaper, there are far greater future expectations from batteries of a lithium-ion technology, as the latter have a higher energy density, fewer losses for each charge-discharge cycle, lower maintenance costs, the ability to perform more charge-discharge cycles for deeper discharges and, as a result, a significantly longer lifespan[114].

Hence, the use of lithium-ion batteries in both PV stand-alone systems and electric vehicle applications is expected to increase considerably over the following decade, which combined with the technological advancements is expected to lead to a major drop in their costs. According to a recent study by UBS[115], today's unit cost of lithium-ion batteries is expected to drop from 360$/KWh, to 200 $/KWh in 2020 and down to 100$/KWh in 2025.

A study by the RMI[116] anticipated a slower development of this drop, especially for stand-alone PV stationary installations. Using data from three different sources (Bloomberg New Energy Finance, Navigant Research and US Energy Information Administration) the analysis estimated a cost of 200 $/KWh by 2035, compared to today's 600 $/KWh. It should be noted that the figures provided in two of these studies lead to even lower estimates, down to 100 $/KWh in the long term.

According to a study conducted by the Morgan Stanley investment firm[117], the move of consumers towards stand-alone systems will take place gradually. At a first stage, the consumers

[114] Suratsawadee A. et al. (2014). «Comparison the economic analysis of the battery between lithium-ion and leadacid in PV stand-alone application», Energy Procedia 56 352 – 358
[115] UBS (2014, August). «Will solar, batteries and electric cars re-shape the electricity system?» http://knowledge.neri.org.nz/assets/uploads/files/270ac-d1V0tO4LmKMZuB3.pdf
[116] Rocky Mountain Institute. (2014, February). "The Economics of Grid Defection"
[117] Forbes. (2014, 25 February). «Morgan Stanley's Bull Case For Tesla Goes Past Hot Cars».

stay connected on the main grid, using it to dump excess energy during hours of intense sunshine and to draw energy at night. In the next stage, the consumers use the main grid only in emergencies and, in all other cases, rely on storage. As the cost of 'emergency' services go up, consumers move to the third stage, i.e. full independence from the grid. While the first stage can be considered as equivalent to net metering, the following two stages correspond to combined PV-battery storage systems.

There were thus two scenarios examined as part of the economic assessment of a PV and battery system, in order to simulate the last two stages of the Morgan Stanley analysis. In the first scenario ('MD'), the PV-battery system is considered as being connected to the grid and falls within the net metering framework, according to the recent Ministerial Decree. The prosumer is liable to SGI charges for the entire energy consumption, and liable to the RES levy depending on the energy drawn from the grid (in this case reduced due to the use of the battery). In the second scenario ('Alternative Plan'), the simulation involves a completely autonomous, stand-alone system, and therefore the avoided cost includes all SGI charges as well as the RES levy. In addition, as there is no connection to the grid in place, any initial connection costs and fixed costs are also avoided.

The battery's capacity is chosen with the aim of it being able to meet the average daily needs for a specific number of days (days of autonomy), to operate in a given depth of discharge (a fraction of its nominal capacity), and at a certain efficiency rate in terms of charging and discharging. The numeric values of these parameters and the unit cost of the battery that were used in the nominal calculations are presented in Table 6.5. Any other values used in the calculations were taken as equal to those given in Table 6.1, in order for the comparison with the net metering case to be feasible.

It should also be noted that the energy losses resulting from the battery's charge-discharge cycle increase the necessary PV capacity to meet a given annual consumption. More specifically, let's assume that the energy needs of a household can be met by a PV system (no battery used) of a certain A capacity, under a net metering scheme. If the same needs are to be met by a combined PV-battery system of efficiency e (e<1), the required PV capacity will be equal to A/e. Finally, according to the assumptions made in the RMI study[116], it was estimated that there would be a need for battery replacement after 15 years, at a unit cost equivalent to that also given in the study.

Table 6.5: PV-battery system values that were used in the analysis

Days of autonomy	2
Depth of discharge (% nominal capacity)[116]	80%
Battery efficiency[116]	90%
Unit cost ($/KWh)[114, 116]	600
Exchange rate €/$	0,75

Table 6.6 presents the calculation results for annual consumption values of 4,000 KWh and 9,045 KWh. The implementation of the Ministerial Decree leads to negative internal rates of return for both cases. This can be explained by comparing the two systems (with and without battery) within the MD scheme, where SGI charges apply. The PV-battery system benefits only by the complete avoidance of regulatory grid charges and the RES levy, unlike the battery-less system that avoids only part of the charges.

On the other hand, however, the PV system with battery storage also needs to account for the battery's high cost and the costs for installing additional PV capacity in order to balance out its energy losses. In the case of a stand-alone system ('Alternative Plan'), the economic evaluation is more favourable compared to a grid connection, but once again the high capital cost of the

---

http://www.forbes.com/sites/samanthasharf/2014/02/25/morgan-stanleys-bull-case-for-tesla-goes-past-hotcars/

battery renders this option economically non Viable as well. Therefore in practice, and for the current prices of lithium-ion batteries, the stand-alone systems are not considered competitive with the electricity provided by the grid.

Table 6.6: Economic analysis results for 4,000 and 9,045 KWh annual consumption rates, for a PV system with battery storage in the 'MD' and 'Alternative Plan' scenarios

Annual Consumption (KWh)	PV Power (KW)	'MD' Scenario		'Alternative Plan' Scenario	
		Payback Period (years)	IRR	Payback Period (years)	IRR
4,000	3.4	>25	-4.17%	>25	-3.57%
9,045	7.5	>25	-3.34%	>25	-1.90%

The most crucial factor in the economic evaluation of a combined PV-battery system is the battery's unit cost. The unit cost of lithium ion batteries shows great variations both today and especially in future development projections[115,116]. The calculation results for different battery unit costs are presented in Table 6.7, assuming a 9,045 KWh annual consumption.

Table 6.7. The effect of battery unit cost assuming a 9,045 KWh annual consumption

Battery unit cost ($/KWh)	'MD' Scenario		'Alternative Plan' Scenario	
	Payback Period (years)	IRR	Payback Period (years)	IRR
500	>25	-2.70%	>25	-1.20%
400	>25	-1.97%	>25	-0.40%
300	>25	-1.13%	23.32	0.54%
200	22.94	0.67%	18.30	2.56%
100	15.61	4.00%	12.26	6.44%

It was estimated that batteries that cost less than approximately 350 $/KWh result to a marginally positive IRR in the case of the fully autonomous system. A 200 $/KWh cost (UBS projection for 2020 and RMI average estimate for 2030) gives a payback period of appr. 18 years with a 2.56% IRR, while for 100 $/KWh the payback drops to 12.3 years (IRR 6.44%).

As lower battery unit costs are expected to lead to lower PV installation costs, scenarios that include such assumptions should also be examined. Table 6.8 shows the results of calculations using different PV unit cost values, for a low battery unit cost. Combining low PV and battery unit costs can offer a full return on stand-alone systems even in less than 10 years; this means that the prosumer will have free electricity for approximately 15 years, which makes these systems very attractive compared to electricity provided by the grid. Needless to point out that this comparison becomes even more favourable if the increase in electricity prices is greater than 2% per annum (see Table 6.4 for the respective results for net metering).

Table 6.8: The effect of PV costs assuming a 100$/KWh battery unit cost and an annual consumption of 9,045 KWh

PV Unit Cost (€/KW)	'MD' Scenario		'Alternative Plan' Scenario	
	Payback Period (years)	IRR	Payback Period (years)	IRR
1,420	15.61	4.00%	12.26	6.44%
1,000	13.36	5.54%	10.41	8.29%
800	12.30	6.41%	9.53	9.37%

The results of the economic assessment are even better in regions of high insolation (similarly to Table 6.3), or if one assumes that the battery can operate at greater discharge depths for the same lifespan, as this would translate to batteries of a smaller capacity. An increase in the battery's efficiency will also yield better results, as it would cause a reduction in both battery capacity and required PV capacity.

In any case, the factors that make PV systems with battery storage unattractive will most likely be overcome within the next 10-15 years. A reduction in battery and PV installation costs, combined with an anticipated increase in household electricity consumption and in energy prices, will make stand-alone systems fully competitive with centralized energy production in Greece. In fact, according to many analysts the future lies with hybrid solutions where the prosumer will be able to store part of the produced energy in batteries, but still remain connected to the grid. Such a system will contribute to the grid's stability by offering storage services, and at the same time allow for the prosumer to use batteries of a smaller capacity, considering the back up offered by the grid.

7. ESTABLISHMENT AND GROWTH OF THE ELECTRIC VEHICLE MARKET

As was discussed earlier in this report, the most important drawback of photovoltaics consists in the lack of absolute control of their intermittent production, which can nevertheless be dealt with by using batteries. Apart from stand-alone PV systems with batteries, there is also the option of storing energy in the batteries of electric vehicles, offering in this way the additional option of using solar energy indirectly in the transport sector. According to a recent study by UBS[115], combining PV, batteries and electric vehicles (EVs) can boost the growth of all three technologies simultaneously.

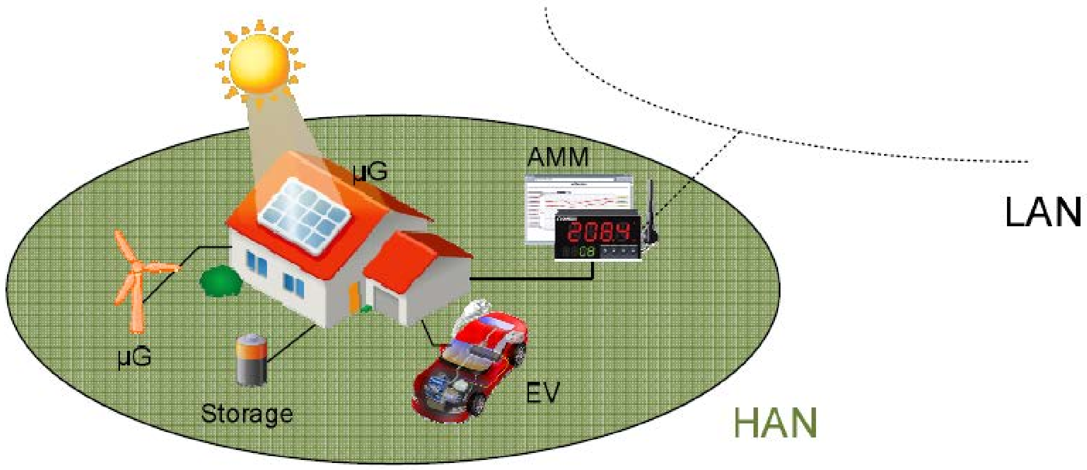


Figure 7.1. Electric Vehicles and RES

According to the study, such systems are already considered economically viable investments in many parts of the world, and have the potential to further improve as a result of the expected drop in the cost of the three technologies involved. Using the battery surplus to charge EVs at night could contribute to daily peak power smoothing. The excess electricity generated by PVs could also be stored in the batteries during the day and be used later on in the evenings. Any additional energy required to cover the demand can come from the grid either at night or early in the morning, when there is an energy surplus in the system and the cost of electricity is lower[115].

Based on the principle of combining various technologies in order to increase the share of RES in the power system, this part of the report offers a short description of the potential of electric vehicles as well as of the effect that its growth can have on the power system and on greenhouse gas emissions.

7.1. Current status and international experience

The carbon emissions of the road transport sector added up to 16% of Greece's total CO_2 emissions in 2012 and comprised 86% of the total emissions in the transport sector, having increased by 16% compared to 1990 levels[118]. Given the country's binding commitments made as part of the Kyoto Protocol with regards to emission reductions by 2020, a set of emission reduction measures in the transport sector is deemed necessary.

According to European Union (EU) targets, Greece is required to reduce its CO_2 emissions by 4% by 2020 compared to 2005 levels, with the 2030 targets also due to be announced soon. At the same time, and accoring to the 2009/28/EU Directive, there is target to reach a 10% RES share in the overall consumption in the transport sector by 2020. According to EUROSTAT data, by the end of 2012, Greece had reached an estimated share of 1.1%, compared to an average 5.8% for EU's 28 member states.

[118] MEECC. (2014). Emissions inventory – Annual inventory submission of Greece under the convention and the Kyoto Protocol for greenhouse and other gases for the years 1990-2012

The consumption in the transport sector was 6,380ktoe in 2012, which is equivalent to 37% of the delivered energy consumption and 23% of the country's total energy consumption. In addition, according to a MEECC report[119], the policy measures aimed at reducing the energy consumed in the transport sector, and road transport in particular, include:

- Replacing 10,000 older light trucks in the private and public sectors by 2020, with an estimated energy saving of 11.3ktoe.
- Replacing 50,000 passenger vehicles in the private sector by 2015, with an estimated energy saving of 22.7ktoe.
- Using LPG in 10,000 passenger cars in the private sector by 2020, with an estimated energy saving of 9.9ktoe.
- Developing Thessaloniki's underground public transport system by 2020, with an estimated energy saving of 21.4ktoe.
- Expanding Athens' underground public transport system by 2020, with an estimated energy saving of 29.34ktoe.

The potential for reducing transport emissions can be summarized in the following:

- ✓ Improving vehicle performace,
- ✓ Using alternative fuels,
- ✓ Using new technology vehicles such as hybrid or electric vehicles with batteries,
- ✓ Changing citizen behaviour (use of public transport, bicycle, walking etc.)
- ✓ Improving the organization of the supply chain.

Reducing transport emissions in the medium-term can be principally be achieved by improving the performance of conventional vehicles. The EU has announced a series of policies in that direction that, amongst others, will set a tight limit of 95 $grCO_2/km$ on the CO_2 emissions of new vehicles, compared to 130 $grCO_2/km$ that it is today. However, the greatest savings in emissions can be achieved by improving the technology of conventional vehicles, and are estimated at approximately 30-35%[120].

At the same time, the use of alternative fuels is also encouraged. Since 2000, the EU has made a turn towards diesel and has gradually adopted new fuels such as LPG, natural gas, electricity, hydrogen but also fuel mixes such as petrol-bioethanol, oil-LPG, petrol-natural gas[121]. The pros and cons of each fuel type are presented in the Table 7.1, based on their energy density, GHG savings, air quality and more[122].

[119] MEECC. (2013, December). "Report based on article 7, par. 9 of the 2012/27/EU Directive of the European Parliament and Cimmission, regarding energy performance, amending the 2009/125/EU and 2010/30/EU Directives and suspending the 2004/8/EU and 2006/32/EU Directives" http://ec.europa.eu/energy/sites/ener/files/documents/article7_el_greece.pdf

[120] MEECC. (2012, January). Investigating new ways of introducing and developing electric vehicles in Greece, http://www.opengov.gr/minenv/wp-content/uploads/downloads/2012/01/texniki-ekthesi.pdf

[121] Nanaki E., Koroneos C. (2013) Comparative economic and environmental analysis of conventional, hybrid and electric vehicles-the case study of Greece. Elsevier Journal of Cleaner Production 53 (2013) 261-266

[122] Kay D., Hill N., Newman D. (2013) Powering ahead – The future of low carbon cars and fuels, Ricardo – AEA

Table 7.1: Comparison of various alternative fuels against key criteria[122]

Fuel	Energy Density	GHG saving	Air quality	Infrastructure	Availability (current)	Future resources
Petrol	+++	---	--	+++	+++	--
Diesel	+++	--	---	+++	+++	--
Natural gas	-	-	+	-	+	-
LPG	-	--	-	++	++	-
Electricity	---	++/+++	+++	+	--	+++
Hydrogen	--	+/+++	+++	---	---	++
Bio-diesel (first-gen.)	+++	+	---	++	+	-
Bio-diesel (advanced)	+++	++	---	+++	--	+
Bioethanol	++	+/++	--	++	+	+
Biomethane	-	++	-	+	-	+

Source: Ricardo-AEA
+++ highly positive, --- highly negative

One of the options for meeting climate change policy targets is the development of EV technology. EVs are partly or fully powered by electricity, which by replacing fossil fuels, leads to major reductions in air pollutant emission and to subsequent improvements in the air quality of the urban and suburban environment. Compared to conventional vehicles, they have a great potential for energy savings and as a result reductions in GHG emissions. The latter could be further reduced and even completely eliminated by the growth of EV, depending on the overall share of RES in power generation.

The main EV technologies that are either available or under commercial development in the international market are the following:

1. Hybrid Electric Vehicles-HEVs: Vehicles with at least two energy converters and two separate internal storage systems. External sources are not required for battery charging.
2. Battery Electric Vehicles-BEVs: Vehicles powered and operated using only the electricity of their batteries, without an alternative fuel source.
3. Extended-Range Electric Vehicles-EREVs: Vehicles powered by battery for a certain number of kilometers, beyond which a conventional engine is used.
4. Plug-in-hybrids (PHEVs): A subcategory of hybrid vehicles that can be recharged externally. These vehicles can operate by combining both electric and conventional engines, depending on their type and power requirements.

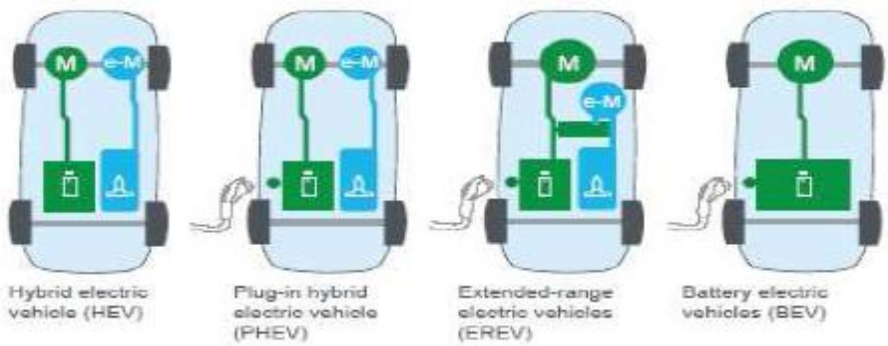


Figure 7.2. Operational characteristics of EV depending on the technology used[120]

Many countries have already taken important support measures and have provided financial incentives in order to increase the market share of EVs. The support measures in most cases include tax and duty exemptions, while the financial incentives offer reductions in the initial costs in the form of subsidies, in order for them to become more attractive to consumers. For example, EV purchasers in Spain receive a sum equal to €6,000 or to 25% of the vehicle cost, while in Japan, apart from deductions in road and classification taxes, discounts on the selling price can reach up to €14,004[120]. In Greece, EVs are exempt from road and classification charges and are additionally given a free entry permit for Athens' City Centre Inner Ring. In November 2013, EVs also became exempt of the Luxury tax[120].

As far as charging inastructure is concerned, the European Commission – in an attempt to promote green transport in the EU – suggested that a minimum number of EV charge stations be available in each EU member state by 2020, 10% of which should be in public spaces. According to a January 2013 press release, Greece's target is to provide 13,000 charging points by 2020[123].

There are currently 13 charging points in operation in Athens. The first public stations of semi-fast charging were installed in December 2013, while a direct current (DC) fast charging station was also installed in February 2014 - the first one in Greece and one of only a few in Europe. The first phase the network's development comprises installing 40 charging points, including 4 DC fast charging stations. In comparison, in 2011, there were 703 charging points in the UK, 1,937 in Germany, 1,600 in France, 1,350 in Portugal, 1,350 in Italy and 1,356 in Spain.

There were 180,000 EVs worldwide in 2012, which accounts for only 0.02% of the total number of passenger vehicles, 40% of them found in the USA, 25% in Japan and 11% in France. However, EV sales are globally increasing at a fast pace, and have more than doubled in 2012 compared to 2011, reaching 113,000 from 45,000. In 2014, the number of EVs exceeded 400,000. Most of them are still found in the USA, followed by Japan, Denmark and Norway, where 20% of the cars sold are actually electric vehicles. There is a target for EVs to reach 2% of the total passenger vehicles by 2020, i.e. approximately 20 million[124]. Table 7.2 shows a comparison between the current EV status of the USA, Japan and four other European countries (Germany, Spain, Portugal and Greece).

Table 7.2: Current status, promotional measures and EV targets

	USA	Japan	Germany	Spain	Portugal	Greece
Number of vehicles	225,000 (2013)	80,000 (3/2014)	21,256 (9/2014)	35,378 (2011)	233 (2011)	62 (2014)[125]
Growth rate	230% (2013 vs 2012)	-	150%	-	-	-
Target	1,000,000 (2015)	-	1,000,000 (2020)[123]	2,500,000 (2020)[123]	200,000(2020)[123]	-
Number of charging stations	10,380 (2014)[126]	4,700 (2014)[127]	2,658 (2014)[128]	1,356 (2011)[123]	1,350 (2011)[123]	11 (2014)[128]
2020 Target	-	2,000,000 slow and 5,000 fast charging[129]	150,000[123]	82,000[123]	12,000[123]	13,000[123]

---

123 Press Release, European Commission. (2013, 24 January). http://europa.eu/rapid/press-release_IP-13-40_el.htm

124 IEA. (2013). «Global EV Outlook – Understanding the Electric Vehicle Landscape to 2020». http://www.iea.org/publications/globalevoutlook_2013.pdf

125 Liaggou, Chryssa. (2014, 24 September). «Use of electric vehicles expected to proliferate». Άρθρο Ekathimerini. http://www.ekathimerini.com/4dcgi/_w_articles_wsite2_1_24/09/2014_543191

126 The alternative fuels data center, http://www.afdc.energy.gov/ , United States Department of Energy

127 Mukai, A., Hagiwara, Y. (2013, 20 Ιουνίου). «Japan carmakers team up to add number of electric chargers». Bloomberg. http://www.bloomberg.com/news/2013-07-29/japan-carmakers-team-up-to-hasten-buildup-ofelectric-chargers.html

128 Chargemap.com, http://chargemap.com/stats/germany

129 Plug in electric vehicles in Japan, http://en.wikipedia.org/wiki/Plug-in_electric_vehicles_in_Japan

Institutional / Tax measures	Tax exempt up to 5,732€[120]	Sell discounts up to 14.004€, road and classification taxes[120]	Road tax exemption for up to 10 years from the date of registration[130]	Return equal to up to €6,000 or 25% of the EV selling price[120]	Exemption from road taxes and classification duty[130]	Exemption from road taxes, classification duty, luxury tax, and free permit to enter Athens' City Centre Inner Ring[120]

Despite its important growth, the electric vehicle market has yet many challenges to face, such as:

- The high cost of EV batteries, which increases the capital cost of the vehicles
- Limited autonomy
- Slow charging
- Lack of charging infrastructure
- Public opinion

The most important of these challenges are discussed below.

7.1.1 Battery cost

The battery of an EV is the technical characteristic that has greatest impact on its cost, compared to conventional vehicles. For example, the production cost of a ion-lithion battery is estimated at €380-450 per kWh, and is expected to drop to €300-350 per kWh by 2020 and €250 per kWh beyond that, provided that the required economy of scale is achieved. Therefore, the production cost of an EV using a 30kWh battery (installed power) is greater by €12,500-15,000 compared to similar one using conventional technologies[131].

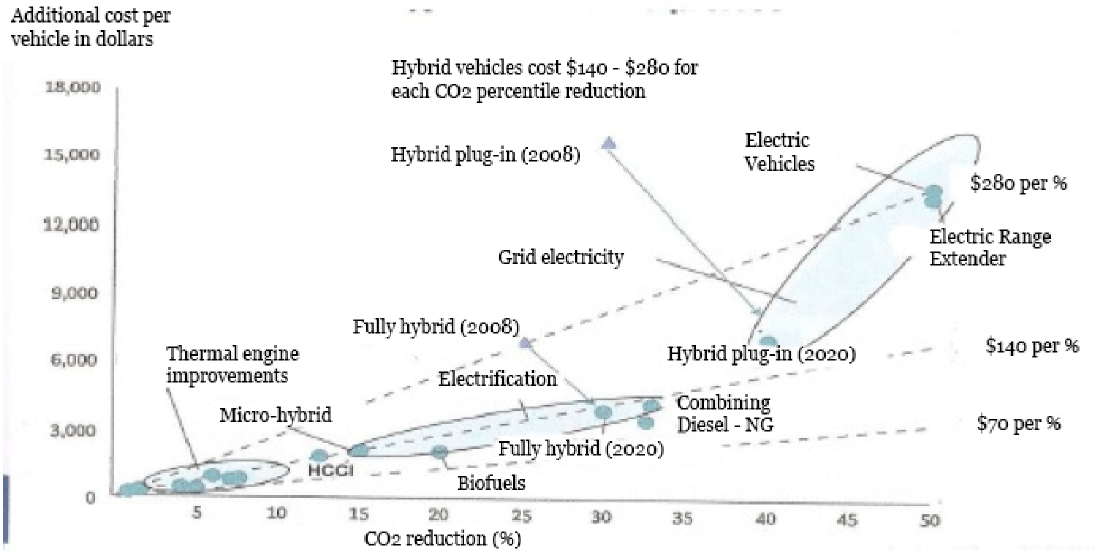


Figure 7.3. Additional cost and emissions reduction rate per vehicle type120

[130] ACEA, 1/4/2014, "Overview of purchase and tax incentives for electric vehicles in the EU", http://www.acea.be/uploads/publications/Electric_vehicles_overview__2014.pdf

[131] Chatzikomis C., Spentzas K., Mamalis A. (2014) Environmental and economic effects of widespread introduction of electric vehicles in Greece, Springer

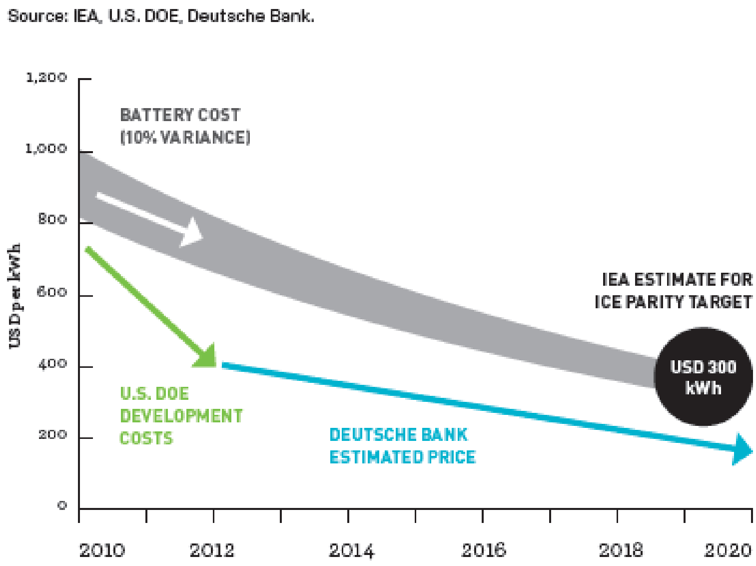


Figure 7.4. Estimated battery cost till 2020 [124]

7.1.2 Autonomy

The battery of an EV is directly linked to its autonomy, i.e. the kilometers it can cover without the need for a recharge. The autonomy of an EV today is estimated at 160km[132], which is approximately one quarter of the equivalent value for a conventional, petrol-fired vehicle. Figure 7.4 shows the development of the autonomy and the expected CO_2 emissions reduction potential per vehicle type, till 2050. The greatest autonomy is achieved by vehicles using diesel, followed by petrol-fired and hybrid ones. Electric vehicles using batteries are the least autonomous.

The autonomy of EVs depends on the energy density of their battery, i.e. the electricity it can store per unit of volume. At the same time, it's important to keep the battery weight to a minimum, as more weight translates to increased vehicle consumption and higher battery construction costs. A typical EV battery nowadays weighs approximately 150 kilos. Manufacturers are expecting the autonomy to increase as a result of improvements in the energy density, which is expected to reach 200-250 Wh/kg by 2020, compared to today's 100-150 Wh/kg. Given that the consumption of an EV ranges between 0.15-0.20 kWh per km, that would lead to a maximum autonomy of 200-250 km[132].

[132] Deloitte Global Services Limited (2011). "Unplugged: Electric vehicle realities versus expectations"

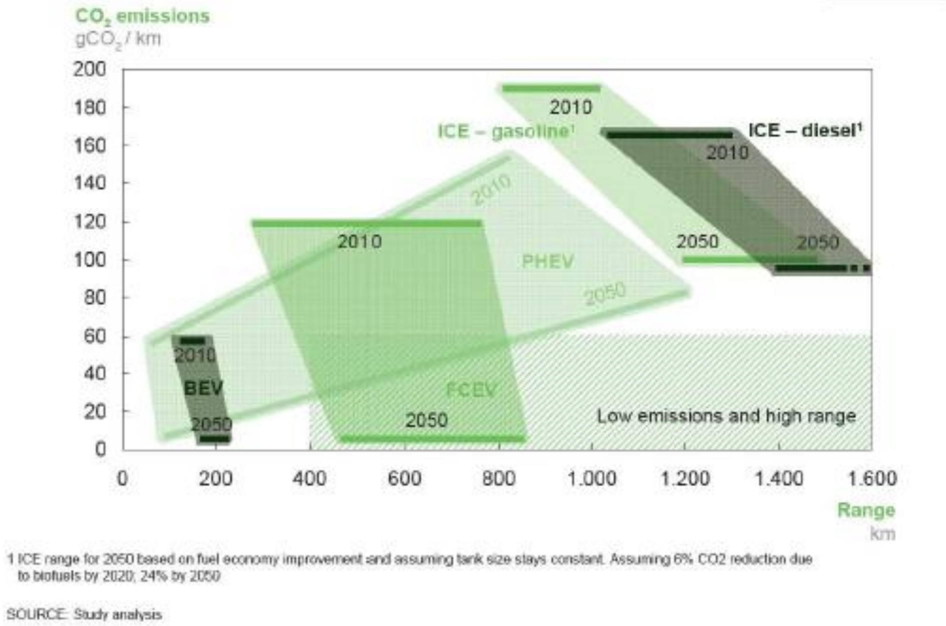


Figure 7.5. The autonomy and emissions reduction potential per vehicle type[120]

The table below presents the fuel, fuel consumption and autonomy of various types of vehicles[121]. It is worth noting that, similar to conventional vehicles, the fuel consumption of EVs depends on their use.

Table 7.3 presents the indicative values taken for hypothetical scenarios regarding the introduction of EV in Greece in a study by Chatzikomis C., Spentzas K. and Mamalis A. for city, rural and highway driving[131]. Driving electric vehicles in the city does not lead to increased consumption, as the efficiency of the electric engine is less dependant on the carrying load, and the energy used for braking can be partly regenerated. On the other hand, driving at high speeds does consume more energy. As a result, electric vehicles driven in cities have a higher degree of autonomy than when driven on highways[133].

Table 7.3: Technical characteristics of three vehicle types (TOYOTA; CITROEN; MEPPW, 2011; PPC, 2011; GCEP, 2006; Gaines and Cuenca, 2000; Petersen, 2009;Nemry et al., 2009)121

Vehicle type	Fuel	Fuel consumption (MJ/100km)	Autonomy (km)
Conventional	Petrol	217.6	588
Hybrid	Petrol	134.4	952
Electric	Electricity	72	129

Table 7.4: Technical characteristics depending on the driving environment[131]

	Driving in cities	Driving in rural areas	Driving on highways
Use	70%	20%	10%
Conventional vehicle	7.5l/100km	5.2l/100km	6.7l/100km
EV with battery	20.4kWh/100km	20.8kWh/100km	24.9kWh/100km
Hybrid EV	4.6l/100km	4.2l/100km	4.9l/100km

[133] IEA-Renewable Energy Technology Deployment (2010) RETRANS - Opportunities for the use of renewable energy in road transport

7.1.3 Charging time and infrastructure

Charging times depend mainly on the voltage level. Full charging at voltage levels between 208-240V using alternating current can take 3 to 8 hours. If fast charging is used (continuous current at 480V), a full charge can take less than 30 minutes[132].

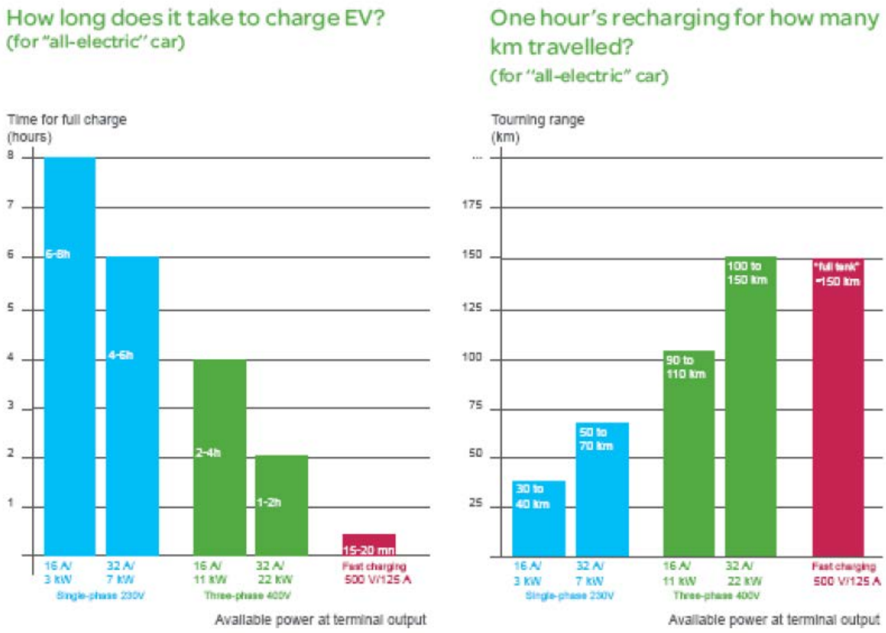


Figure 7.6. Characteristics of charging stations (left) and corresponding autonomy range (right)[120]

In February 2014, RAE initiated a public consultation regarding the institutional and operational framework for introducing EV charging infrastructure in Greece. According to this framework, charging stations can be constructed and operated at three different levels:

- In private spaces
- In areas belonging to public bodies
- In commercial/business areas, by EV charge infrastructure companies

7.2. The potential of electric vehicle introduction to Greece

The effect that electric vehicles have on the system and on GHG emssions depends on a number of factors, such as:

- the energy and materials used for manufacturing them
- the electricity consumed during their use
- the required charging times
- the ratio of electric vehicles to total number of vehicles
- the emission intensity of the power generation network

7.2.1. Effect on emissions

In order to estimate the precise effect that electric vehicles have on emissions, their overall life-cycle needs to be examined. There are more pollutants emitted during the construction of an EV compared to a conventional vehicle, due to the increased demands in energy and materials for manufacturing the batteries. For example, the energy required for manufacturing an lithium-ion battery is approximately 1,700 MJ/kWh, while for different types of batteries, such as e.g. NiMH, it can reach up to 2,680 MJ/kWh.

As there are approximately 120-166 kgCO_2 per kWh of battery emitted during the manufacturing of an lithium-ion battery, an EV using a 30 kWh battery is expected to emit an additional 3.6-5.5 ton of CO_2 equivalent. According to the life-cycle analysis of an average-size electric vehicle, the carbon emited during production is equal to approximately 8.8 ton of CO_2 equivalent and accounts for 57% of the total emissions emitted during the vehicle's life-cycle. For a medium-sized vehicle operating on petrol, the corresponding carbon share is estimated at 25%[131].

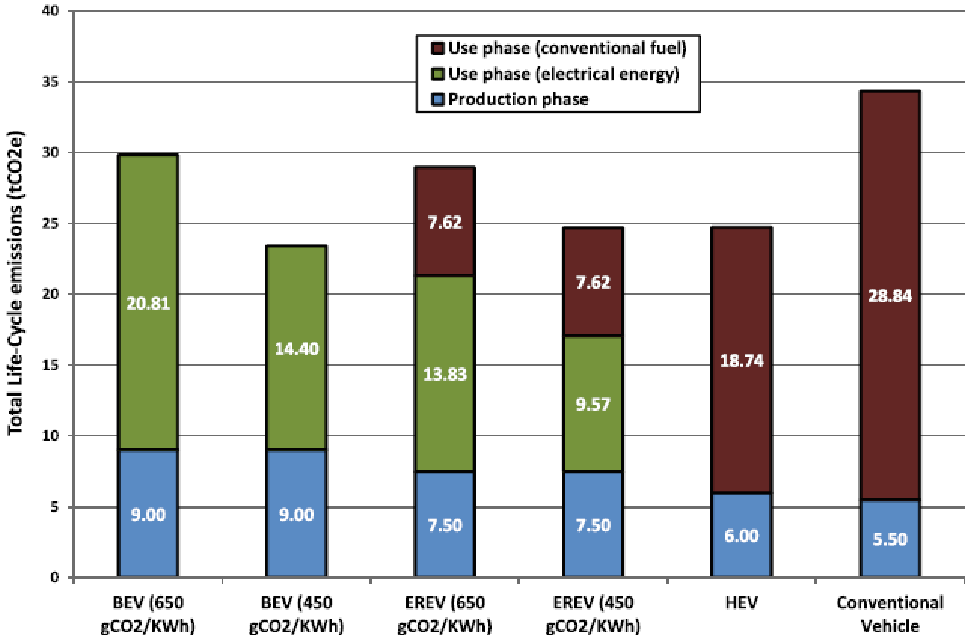


Figure 7.7. Life-cycle emissions comparison per vehicle category[131]

On the other hand, the operation of EVs has no direct emissions. The indirect emissions result from the way that the electricity used for their charging is produced. Hence, the emissions resulting from the use of electric vehicles are related to the emission intensity of the given country's power generation system. Therefore, in order to eliminated any negative associated with the use of EVs, RES need to be adequately employed in the power generation system. Table 7.5 compares different EV emission rates depending on the emission intensity of the power network.

Table 7.5: Comparison of various emission rates depending on the emission intensity of the power network[134]

Vehicle Type	Well to Tank (Batteries)	Tank (Batteries) to Wheels	Total CO_2 emissions
Conventional ICE car	25-35	120-180	145-215*
Electric Vehicle 27% nuclear, 20% renewable, 53% fossil (EU-27 mix 2010)	85-105	0	85-105
Electric Vehicle 11% nuclear, 20% renewable, 69% fossil (EU Italian mix 2010)	120-140	0	120-140
Electric Vehicle 75% nuclear, 20% renewable, 5% fossil (French mix 2010)	20-25	0	20-25
Electric Vehicle 30% photovoltaic on board, 60% other renewable , 10% fossil	18-22	0	18-22
Electric Vehicle 50% photovoltaic, 50% wind (Carbon-free communities)	8 5km per kwh and 40 g/kWh	0	8

The Greek power system has a high emissions intensity factor, mainly due to the widespread use of lignite in power generation (see Chapter 2). The intensity of CO_2 emissions is estimated between 650 and 846 gCO_2/kWh[131]. According to a different source[120], as of today, the average intensity factor of the Greek power generation mix is equal to 833 gCO_2/kWh. Meanwhile, the average factor of the remaining 27 member countries of the EU is estimated at 467 gCO_2/kWh[131]. The CO_2 power generation intensity in Greece is expected to drop to 530 gCO_2/kWh by 2020, as a result of the country's binding targets regarding a 20% reduction in emissions and a 20% share of RES in power generation[131].

As RES power generation increases, closing down old lignite plants will lead to further reductions in emission intensity[120]. In a hypothetical scenario where the RES share would exceed 50% and carbon capture and storage technologies (CCS) would be used in lignite stations, the emissions intensity would drop to 36 gCO_2/kWh. An RES share of 50% and a 40% efficiency for lignite plants would lead to a 428 gCO_2/kWh intensity[121].

A study by E. Nanakis and C.Koroneos[121] regarding the likely effect of EV growth to the emissions of the Greek power generation system, assuming three different emission intensities, concluded that the GHG emissions of electric vehicles would in all cases be less than those of conventional ones. EV, whether hybrid or battery-electric, prove to be particularly effective when the RES share in power generation exceeds 50%. If the share of fossil fuels remains above 50%, then hybrid vehicles (HEVs) outweigh battery-EV, mainly due to their autonomy, lower capital costs, and less air pollutants emissions[121].

[134] European Commission (2011) European Green Cars Initiative, http://ec.europa.eu/research/transport/road/green_cars/index_en.htm

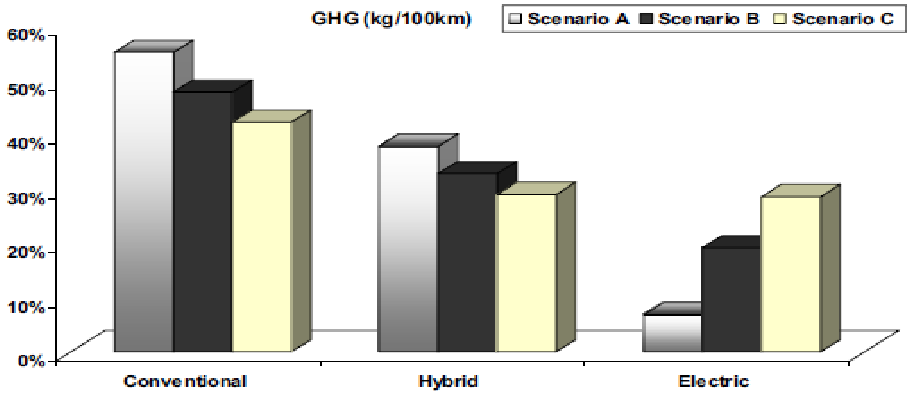


Figure 7.8. Share of each vehicle type over the total GHG emissions (kg/100km). Scenario A: Low emissions scenario with a 36gCO_2e/kWh power system intensity. Scenario B: 428gCO_2e/kWh power system emissions intensity. Scenario C: 820gCO_2e/kWh power system emissions intensity[121]

This highlights the importance of developing both RES and EV at the same time. Besides, the growth of EV as part of an ambitious energy saving policy, will maintain the power demand at the level necessary in order to attract investments in infrastructure (network, production units), and will lead to an overall reduction in the system's emissions. On the other hand, in order for EV to make full use of their advantages compared to other solutions and in order to achieve an even greater emissions reduction and independence from imports or/and fossil fuel use, the development of RES in nessecary[133].

7.2.2. RES and electrification of transport

As was highlighted above, the effect that EV can have on reducing Greece's GHG emissions becomes greater as the share of RES in the energy mix increases. There is, however, one additional reason for supporting the development of both RES and electric vehicles.

There is a limit to the amount of RES that can be used in the power generation system, due to technical and economical limitations arising from their variable nature of production, which is dependant on weather conditions and the the time of day. The high variability of certain RES - such e.g. wind farms - can lead to serious disruptions in the overall behaviour of the grid, particularly in isolated power systems.

Moreover, during hours of reduced demand (valley hours), RES generation can exceed demand and therefore need to be stopped, which should by all means be avoided. Apart from the associated environmental impacts, cutting off RES production can make these technologies economically unattractive, as it would force them to stop generating power while resources are still available. However, the use of EV can tackle this issue and at the same time facilitate the overall growth of RES.

As was concluded during the MERGE[135] programme that was completed in 2011, EV can, under certain circumstances, bridge the gap between the RES power demand and electricity production curves. This can be achieved by using EV as temporary storage means and/or by charging their batteries during hours of low demand. In order for that to happen, EV charging would need to be regulated using 'smart grid' systems. The calculated results of different scenarios regarding the number of hours of RES power surplus as a function of EV growth and the charging method are given in Figure 7.9[135]. There can be an important reduction in the energy surplus of RES, which will consequently allow them to grow faster in the power system, by controlling thri hours of charging using either different billing rates (dual charging) or smart systems. The effect that the growth of electric vehicles would have in the system is described below.

[135] EURELECTRIC Task Force on Electric Vehicles http://www.ev-merge.eu/

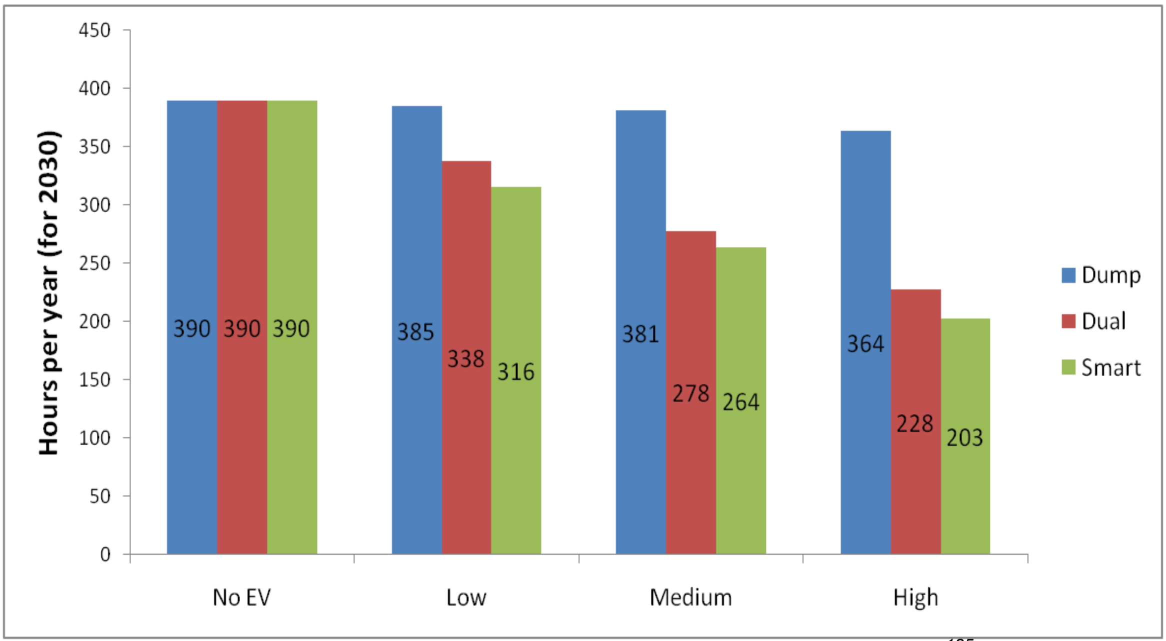


Figure 7.9. Number of hours with an RES power surplus in 2030[135]

7.2.3. Effect on the system

According to the results of the MERGE[135] study, while a limited growth of battery-EV systems till 2020 would have no major impacts, a more widespread use till 2030 would most likely disrupt the operation and management of the existing network.

An increase in EV use would also lead to significant increases in electricity consumption, as the annual energy needed to charge a medium-sized city vehicle is almost equal to that consumed in a typical household over the course of a year. Hence, a non-regulated charging of EV is very likely to bring up congestion issues to the power network. Moreover, if charging takes place during peak hours, an increase in consumption would also increase peak loads, and hence network losses. Finally, if many EV are charged at the same time, the network will be overcharged and voltage drops and frequency deviations should be expected[136,133]. In order to deal with the above, it is necessary to:

- Improve current infrastructure,
- Design new networks in a way that will allow them to manage a large increase in battery-operated EV,
- Design and implement improved strategies for managing the load in distribution networks, which will be capable of controlling the charge of EV according to the needs of both the network and their owners. This will both benefit the networks and reward the owners for the services offered.

The distribution of EV power demand throughout the day depends on the time and duration of charging and on the availability of charging instrastructure (in houses, work, public spaces etc.). These factors dictate the changes in the system's daily demand and can vary depending on each case. When the charging of an EV is non-regulated, its demand can coincide with the time people get back home from work. As that is usually the highest hour of demand in the residential sector, EV demand would be syncrhonized with the system's peak load.

Hence, 'blind' charging can lead to a local congestion in the distribution network and a higher increase in EV use will eventually lead to an earlier need for new investments. The impacts of home-charging on the network can be reduced by developing charging infrastructure in

---

[136] Garcia Valle R., Pecas Lopes J. (2013) Electric Vehicle Integration into Modern Power Networks. Springer Power Electronics and Power Systems Book

workplaces. In that case, part of the EV charging demands could be covered in the mornings, when system demands are relatively low. Another strategy would be to synch the charging of EV using 'smart' systems at night, thus filling up the 'valleys' of the load demand curves and improving the overall operation of the system.

'Smart' charging contributes to avoiding high peak loads by distributing EV demand to non-peak hours. It manages EV demand in a way that smoothens the load curve of the system, reducing the variability between peak and non-peak hours, reducing its operating costs, and increasing the use factors of power generation plants. While 'smart' charging is the most effective charging strategy, it's application is difficult and - in the case of a widespread use of EV - would require advanced control and management techniques.

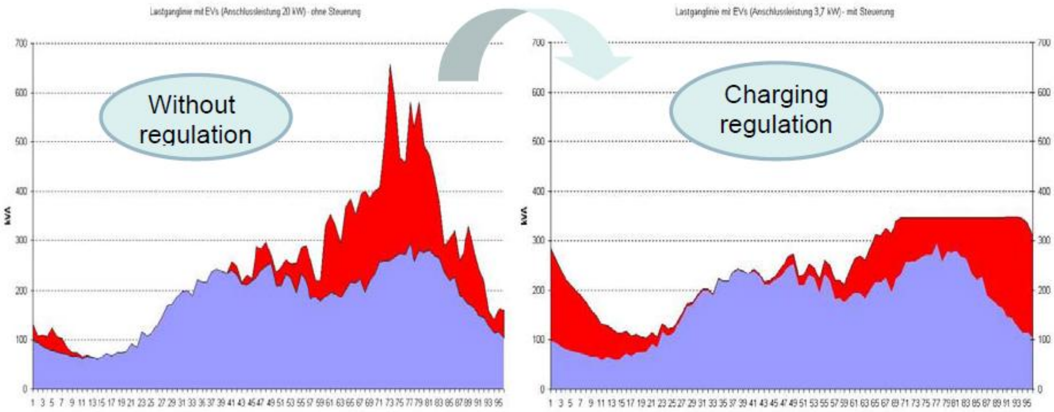


Figure 7.10. Illustration of the effect of regulated charging, for 80% EV use per household[133]

Battery electric vehicles are considered very flexible loads that can additionally be used in the future as mobile storage means, and offer services to the power system[136]. More specifically, EV batteries can be used as regulated loads during charging, by offering 'turning' power backup or by returning the energy stored back to the grid, operating in other words in a vehicle-to-grid mode (V2G) and contributing to the management of peak loads[136]. To give an example, as the peak hours of the system usually occur early or midway through the afternoon, when most cars are parked, their batteries could be supplying any additional energy to meet power demands, if necessary[137].

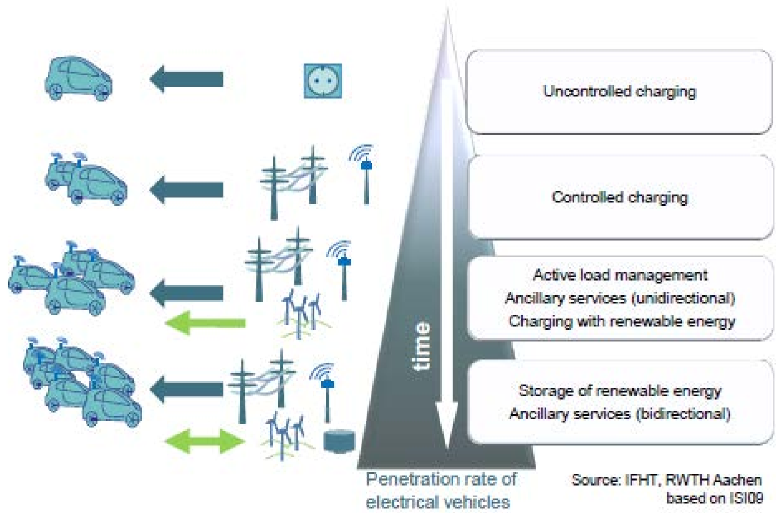


Figure 7.11. Steps required for electric and plug-in-hybrid vehicles to provide services to the system[133]

[137] IEDC. (2013). "Creating the clean energy economy – Analysis of the electric vehicle industry". http://www.iedconline.org/clientuploads/Downloads/edrp/IEDC_Electric_Vehicle_Industry.pdf

A scheme for the full integration of EV in the power system which would also allow them to offer services back to it, is given in Figure 7.11. Each step should be followed by the next. At first, a development of charging infrastructure is required for EV to grow. Regulated charging and demand management requires vehicles and the local system stations to be connected. A one-way connection will suffice at this stage. The next stage includes offering backup services and selective charging only during the hours of RES energy surplus. The system will then need to be optimised in order for EV to be used for energy storage services. The final step is establishing a dual cooonection, so that EV can offer energy and backup services back to the grid[133].

A requisite for establishing a new smart power system similar to the one described above is to replace the conventional meters with 'smart meters', as that will allow to closely follow the electricity consumption of each household. Advanced 'smart' meters will allow the communication between EV and the power system, with the aim of achieving regulated charging and avoiding grid overcharging. The interaction between EV (or another load) and power generation can be facilitated by the use of 'smart' networks that use digital technology to generate energy savings, cost reductions and increase reliability and transparency. 'Smart' networks also facilitate the implementation of load strategies for controlling the balance of the network[133].

8. CONCLUSIONS

The development of a clean energy power generation system, equivalent to a 660 MW lignite plant, is technically feasible and economically and environmentaly more favourable than the planned construction of the Ptolemaida V lignite plant by the PPC.

As is demonstrated in the current study, the construction of the highly-polluting new lignite plant Ptolemaida V, emitting 4.6mt CO_2 , 2,100t SO_2, 2,800t NO_x and 140t particles, can be avoided by converting existing pairs of PPC hydroelectric power stations to pumped hydro energy storage stations that will use the energy produced in wind farms and PV parks. The proposed solution leads to levelised costs of electricity (LCOE) that are significantly lower than those of the new lignite plant.

The comparison between the LCOEs of various electricity generation technologies (Chapter 3) proved that some RES technologies are nowadays directly competitive with conventional power plants, and Ptolemaida V in particular. This trend will continue to grow in the future, as the development of clean technologies will make RES even cheaper, while at the same time the cost of electricity produced in lignite plants is expected to move upwards, for a number of reasons described in Chapter 1.

A further increase in the RES share in the energy mix faces various challenges, as was already discussed in detail in Chapter 4. The most important one is related to the intermittent nature of wind and PV electricity production, which can nevertheless be successfully dealt with by combining RES with various energy storage systems, such as batteries and pumped hydro energy storage systems.

Chapter 5 examines the possibility of substituting Ptolemaida V with hybrid systems consisting of PHES combined with wind and PV units. More specifically, previous studies have demonstrated that converting seven specific pairs of PPC's existing hydropower plants to PHES is technically feasible and economically advantageous, given that it will also eliminate the need for constructing new reservoirs, and minimise the associated environmental impacts. This report illustrated the possibility of covering the same demand load as that of Ptolemaida V, using hybrid combinations of these pumped hydro energy storage stations with wind and PV. The economic analysis showed that many of the hybrid solutions that are energywise feasible, lead to LCOEs that are considerably lower compared to that of the new lignite plant.

It is also worth noting that the minimum LCOE of Ptolemaida V (96.47 €/MWh) that was used in the comparison with the hybrid solutions, corresponds to a capacity factor (90%) that is even greater than the one estimated in the plant's EIA (80%). Furthermore, as a result of the assumptions made regarding the maximum storage capacity available of the existing pair of HP plants that are proposed to be converted to PHES units, the suggested PHES operation is not expected to obstruct, by any means, the way that the specific hydro plants operate today. If the estimates made in a previous study by WWF Greece[20], regarding the reduction in the hours of operation of the new plant due to the growth of RES, are correct, then the comparison will turn out to favour Ptolemaida V even less.

This hybrid RES-PHES solution might turn out to be even more attractive if one takes into account the reduced demand that Ptolemaida V will be required to meet beyond 2020, not only because of the projected increase in the contribution of large-scale RES, but also because of the recent technological advances regarding both PV and batteries. These will play a key role in the upcoming, drastic transformation of the existing model of electricity generation: from centralized, huge power plants operating on fossil fuels such as Ptolemaida V, towards decentralized, stand-alone systems and ultimately a gradual independence from electricity provided by the grid. As is concluded in the economic assessment of Chapter 6, the potential that net metering has for developing small-scale photovoltaics in order to meet household electricity demands – given the high levels of insolation in Greece – is excellent, and will not place any burden on LAGIE's RES special account. In addition, that potential can become even greater should the recent Ministerial Decree shift towards the direction of the ‘Alternative Plan’ proposed in Chapter 6.

Fully autonomous PV systems using lithium-ion batteries can also become economically competitive with grid electricity in the future, especially if the estimates of various analysts regarding an upcoming technological revolution in the battery sector are realised, as that will lead to a dramatic drop in their cost over the next 10-15 years. In fact, according to many analysts the future lies with hybrid solutions where the prosumer will be able to store part of the generated energy in batteries, but still remain connected to the grid. Such a system will contribute to grid stability by offering storage services, and at the same time allow for the prosumer to use batteries of a smaller capacity, considering the back up provided by the grid. Apart from PV stand-alone systems using batteries, there is also the potential for storing energy in the batteries of electric vehicles, which will offer the additional option of using solar energy in the transport sector. Hence, there is a high probability of a drastic drop in the power demand that Ptolemaida V will be asked to meet between 2020-2050.

The current study does therefore demonstrate that lignite dependency is not the only option for Greece, suggesting at the same time specific alternatives that can eliminate the need for constructing the Ptolemaida V plant. In this context, WWF Greece is calling for the Greek state to:

- Re-examine the financial viability of the new power plant and evaluate the equivalent alternative solutions proposed.
- Establish the appropriate institutional framework regarding pumped hydro energy storage systems.
- Improve the regulatory framework regarding net metering and as a next step, enforce a policy mechanism that will promote the development of small-scale, stand-alone RES systems.
- Provide the necessary infrastructure for the growth of the electric vehicle market in Greece.
- Plan a new business model for PPC built around profitable sectors that will maximise the benefits of the business, the customers and the environment.
- Set out a national energy plan that will take into account the emerging developments in the field of clean energy at an international level and will delineate the development over time of each electricity generation technology’s share in the country’s energy mix, up to 2030 and 2050.

ANNEX I: DESCRIPTION OF THE CALCULATION METHODOLOGY – INDICATIVE RESULTS

X1. Computational code

In order to investigate the proposed alternative solution to the construction of Ptolemaida V, a complete methodology was developed, based on the elaboration of an analytical computational code for the energy simulation of hybrid RES-pumped hydro energy storage systems. The energy results of the computational code can be used for the economic evaluation of the proposed solution and the presentation of optimum hybrid RES-PHES schemes. The steps / different stages that were followed as part of the methodology's comprehensive approach can be summarized as follows:

X.1.1 Calculation of hourly capacity factor distributions

A1 Use of the hourly NIS net electricity production data timeline for each of the participating energy sources (lignite, natural gas, oil, large hydro, small hydro, imports, wind power, solar power, other RES) between 1/1/2009 – 31/12/2012.

A2. Calculation of the annual average distribution of the hourly capacity factor for the given period, for wind and PV parks of mainland Greece, using hourly data for net wind and PV production, combined with the corresponding development of the installed capacity on a monthly basis in the same timeframe, assuming that the later grows exponentially at a fixed rate, in order to convert monthly data to daily.

A3. Calculation of the annual average distribution of the hourly capacity factor for the given period by taking into account the net production data (see Annex II – Table AN1 and ***Figure 2.5***) for the NIS liginte units, in order to simulate in a more realistic way the operation of Ptolemaida V, equivalent to the substitute base load that the proposed hybrid solution is required to meet. In particular, a production profile based on NIS lignite plants with high loads is adopted (specifically Agios Dimitrios V, Figure 2.3), with the aim of administering the 'worst case' production scenario, and at the same time verify the estimates for the annual average capacity factor (or hours of operation) of the Ptolemaida V unit, with a an annual net production of ≥ 4,160GWh.

A4. Calculation of the hourly distribution of the weighted average capacity factor in the given period, for all the large hydro plants of the NIS (Figure 2.10), in order to estimate with a high accuracy the load level of the existing units and therefore the operating margins of combined operation (conventional hydro and PHES) on an hourly basis.

X.1.2 Calculation Methodology

B1. Development of an analytical computational code for the hourly simulation of the operation of hybrid RES units (wind and PV) and PHES, examining the following key variables a) installed wind capacity, b) installed PV capacity, c) total storage capacity of PHES stations.

B2. Using the hourly, annual distributions of the capacity factor as data input for the calculation of the expected RES production.

B3. Comparison between the estimated net production from RES and the corresponding demand (equivalent base load of the Ptolemaida V plant – also see step A3) and calculation of the resulting energy surplus / deficit.

B4. Any resulting surplus is used for storing energy by pumping – taking into account pumping energy losses – provided that there is enough storage volume available (difference between the maximum level allowed and the one right before it). Alternatively, if the required volume storage is not available, partial storage until the reservoirs are full is allowed (maximum level).

B5. Any additional surplus resulting from the retention inability of the PHES stations is treated as stochastic RES production and is subject to being rejected, depending on the calculation of the remaining load, based on the assessment of the system's minimum loads.

B6. In the case of an energy deficit (inability to meet the base load demands), an attempt is made to meet the load through PHES, provided that there is enough water storage (90% maximum discharge depth).

B7. Potential for examining two basic scenarios for the operation of the energy storage system, a) as an exclusive PHES station and b) as a combined PHES and conventional hydroelectric production cycle, taking into account the annual, hourly distribution of the average capacity factor for all of the existing large hydroelectric plants of the NIS.

X.1.3 Computational code results

C1. Detailed simulation using the computational code for various wind and PV-based solutions, in combination with different levels of PHES capacity.

C2. Calculation of the maximum pumping power required in order to retain the maximum usable energy surplus resulting from the combined operation of wind and PV parks throughout the year.

C3. Re-calculation of the required pumping capacity, allowing the rejection of higher values of usable energy surplus that have a cumulative frequency of appearance of ≤500 hours, on an annual basis.

C4. Calculation of the maximum hydroelectric capacity required to cover the maximum deficit resulting throughout the year, as a result of the RES units' inability to directly meet the equivalent base load.

C5. Calculation of the hourly load demand (capacity factor) of the PHES turbine units and comparison with the operating margins of the PHES combined cycle. Re-assessment (proportional reduction) of the hydro turbine units capacity factor and of the resulting production during PHES operation.

C6. For each of the examined solutions, registering the annual coverage rate and the hours that the equivalent base load of the Ptolemaida V unit is being rejected, based on the re-calculation of the required pumping capacity and the combined PHES and hydropower operation.

C7. For each of the examined solutions, registering the energy surplus that results on an hourly basis, once the base load demands have been met and provided that the examined reservoirs are fully loaded.

C8. Calculation of the energy surplus hourly rejections by the NIS that result from retain inability, based on the minimum loads of the thermal units and the remaining load per hour.

C9. Calculation of the direct contribution of wind and PV energy, along with the indirect – through PHES - to the annual coverage of the equivalent base load.

X2. Calculation of the required pumping capacity

In order to avoid oversizing the pumping stations, the computational code offers the ability of sizing not only based on the resulting maximum hourly RES surplus (following a comparison between RES production and the equivalent base load demand), but also based on defining a maximum acceptable limit regarding the rejection of the RES surplus by the pumping system. For this purpose, the likelihood of different levels of RES surplus is taken into account, along with the role of storage capacity, by considering the possibility of the RES surplus being rejected due to the reservoirs being full.

On this basis, an estimate is made regarding the probability of occurrence of different levels of fully usable RES surplus, and a maximum acceptable rejection limit is defined, lack of which is likely to lead to oversizing the pumping plants. This way, the RES surplus is used at the desired levels and at the same time a high capacity factor is achieved, and therefore a better economic outcome for the PHES plants. In this context, and following numerous trials, it was chosen to use in this study a maximum RES rejection limit of 500 h/annum or a cumulative annual probability of ~6%, which translates to particularly high RES surplus values.

Figure X1 shows some typical examples of RES (wind or PV) and PHES combinations, the shaded area representing the rejected surplus. The points of intersection between each curve and the shaded area define the required pumping power, based on the maximum acceptable rejection limit. As can be seen, applying a maximum acceptable rejection limit guarantees that oversizing is avoided, with regards to the maximum pumping capacity that corresponds to using 100% of the resulting surplus. At the same time, it’s interesting to note that the increase in storage capacity allows residuals of increased RES power to occur more often, shifting thus the pumping capacity selection point to the right.

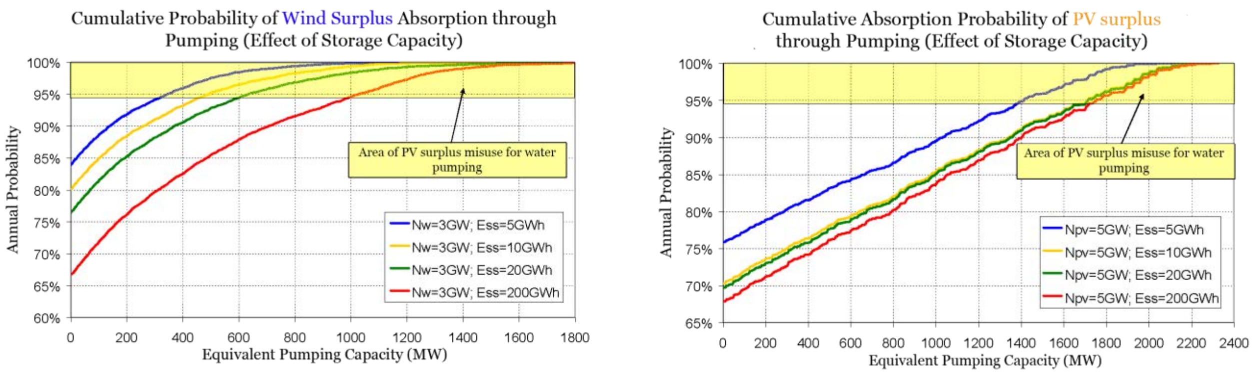


Figure X1. Cumulative probability of RES energy residual occurrence for exclusive wind (a) and PV (b) plants, as a function of the available storage capacity.

ANNEX II: INSTALLED CAPACITY OF THERMAL AND HYDRO POWER UNITS IN THE NATIONAL INTERCONNECTED SYSTEM (NIS)

Table XII.1: Existing NIS thermal units (December 2013)

PRODUCER	PRODUCTION PLANT	PRODUCTION UNIT	INSTALLED CAPACITY (MW)	NET CAPACITY (MW)
Lignite plants				
PPC	Ag. Dimitrios PP	Ag. Dimitrios I	300	274
PPC	Ag. Dimitrios PP	Ag. Dimitrios II	300	274
PPC	Ag. Dimitrios PP	Ag. Dimitrios III	310	283
PPC	Ag. Dimitrios PP	Ag. Dimitrios IV	310	283
PPC	Ag. Dimitrios PP	Ag. Dimitrios V	375	342
PPC	Amyntaio	Amyntaio I	300	273
PPC	Amyntaio	Amyntaio II	300	273
PPC	Kardia	Kardia I	300	275
PPC	Kardia	Kardia II	300	275
PPC	Kardia	Kardia III	306	280
PPC	Kardia	Kardia IV	306	280
PPC	Liptol	Liptol I	33	30
PPC	Liptol	Liptol II	10	8
PPC	Megalopolis A	Megalopolis A	300	255
PPC	Megalopolis B	Megalopolis B	300	256
PPC	Meliti	Meliti I	330	289
PPC	Ptolemaida	Ptolemaida II	125	116
PPC	Ptolemaida	Ptolemaida III	125	116
PPC	Ptolemaida	Ptolemaida IV	300	274
		Total	**4,930**	**4,456**
Oil Untis				
PPC	Aliveri PP	Aliveri III	150	144
PPC	Aliveri PP	Aliveri IV	150	144
PPC	Lavrio PP	Lavrio I	130	123
PPC	Lavrio PP	Lavrio II	300	287
		Total	**730**	**698**
Combined Cycle Natural gas plants (CCU)				
PPC	Komotini PP	Komitini CCU	484.6	476.3
PPC	Lavrio PP	Lavrio III – Small CCU	176.5	173.4
PPC	Lavrio PP	Lavrio IV – Large CCU	560	550.2
PPC	Lavrio PP	Lavrio V – New CCU	385.2	377.6
ELPEDISON ENERGY	ENTHES TPP	CCU ENTHES	395	389.4
BOEOTIA IROON II PLANT	IROON II TPP	CCU IROON II	432	422.1
KORINTHOS POWER	Ag. Theodoroi TPP	Ag. Theodoroi CCU	436.6	433.5
ELPEDISON ENERGY	Thisvi TPP	Thisvi CCU	421.6	410
PROTERGIA THERMAL POWER	Ag. Nikolaos TPP	Ag. Nikolaos CCU	444.5	432.7
		Total	**3,736**	**3665.2**
Open Cycle Natural gas plants				
PPC	Ag. Georgios PP	Ag. Georgios VIII	160	151
PPC	Ag. Georgios PP	Ag. Georgios IX	200	188
HERON THERMAL POWER	HERON TPP	3 units	148.5	147.8

		Total	**508.5**	**486.8**
CHP Dispersed Units				
ALUMINION	Aluminion TPP	3 units	334	334
		Total	**334**	**334**
		TOTAL	**10,238.5**	**9,640**

Table XII.2: Existing NIS hydroelectric plants (December 2013)

PRODUCER	PRODUCTION PLANT	PRODUCTION UNIT	INSTALLED CAPACITY (MW)	NET CAPACITY (MW)
PPC	Agras TPP	Agras I	25	25
PPC	Agras TPP	Agras II	25	25
PPC	Asomata TPP	Asomata I	54	54
PPC	Asomata TPP	Asomata II	54	54
PPC	Edessaios TPP	Edessaios	19	19
PPC	Thisavros TPP	Thisavros I (p.storage)	128	128
PPC	Thisavros TPP	Thisavros II (p.storage)	128	128
PPC	Thisavros TPP	Thisavros III (p.storage)	128	128
PPC	Kastraki TPP	Kastraki I	80	80
PPC	Kastraki TPP	Kastraki II	80	80
PPC	Kastraki TPP	Kastraki III	80	80
PPC	Kastraki TPP	Kastraki IV	80	80
PPC	Kremasta TPP	Kremasta I	109.3	109.3
PPC	Kremasta TPP	Kremasta II	109.3	109.3
PPC	Kremasta TPP	Kremasta III	109.3	109.3
PPC	Kremasta TPP	Kremasta IV	109.3	109.3
PPC	Ladonas TPP	Ladonas I	35	35
PPC	Ladonas TPP	Ladonas II	35	35
PPC	Aoos Springs TPP	Aoos Springs I	105	105
PPC	Aoos Springs TPP	Aoos Springs II	105	105
PPC	Plastiras TPP (Tavropos)	Plastiras I	43.3	43.3
PPC	Plastiras TPP (Tavropos)	Plastiras II	43.3	43.3
PPC	Plastiras TPP (Tavropos)	Plastiras III	43.3	43.3
PPC	Platanovrisi TPP	Platanovrisi I	58	58
PPC	Platanovrisi TPP	Platanovrisi II	58	58
PPC	Polifito TPP	Polifito II	125	125
PPC	Polifito TPP	Polifito II	125	125
PPC	Polifito TPP	Polifito III	125	125
PPC	Pournari TPP	Pournari I - Unit I	100	100
PPC	Pournari TPP	Pournari I - Unit II	100	100
PPC	Pournari TPP	Pournari I - Unit III	100	100
PPC	Pournari TPP	Pournari II - Unit I	16	16
PPC	Pournari TPP	Pournari II - Unit II	16	16
PPC	Pournari TPP	Pournari II - Unit IIII	1.6	1.6

PPC	Stratos TPP	Stratos I	75	75
PPC	Stratos TPP	Stratos II	75	75
PPC	Sfikia TPP	Sfikia I (p.storage)	105	105
PPC	Sfikia TPP	Sfikia II (p.storage)	105	105
PPC	Sfikia TPP	Sfikia III (p.storage)	105	105
		TOTAL	**3,017.7**	**3,017.7**

ACRONYMS

BAT	Best Available Techniques
CCGT	Combined Cycle Gas Turbines
CCS	Carbon Capture and Storage
EU ETS	EU Emissions Trading System
EV	Electric vehicle
FiTs	Feed-in tariffs
HEDNO	Hellenic Electricity Distribution Network Operator
HP	Hydroelectric power
IRR	Internal rate of return
LAGIE	Hellenic Electricity Market Operator S.A.
LCOE	Levelized Cost of Energy
LPG	Liquefied petroleum gas
MEECC	Ministry of Environment Energy and Climate Change
NIS	National Interconnected System
OCGT	Open Cycle Gas Turbine
PPC	Public Power Corporation S.A.
PV	Photovoltaics
RAE	Regulatory Authority for Energy
RES	Renewable Energy Sources
SHPP	Small hydropower plants
SGI	Services of General Interest

“We shan’t save all we should like to – but we shall save a great deal more than if we never tried.”

Sir Peter Scott, founding chairman of the World Wildlife Fund (WWF)

WWF Greece

21 Lempessi street
117 43 Athens

Tel.: +30 210 3314893
Fax: +30 210 3247578

Information:
Nikos Mantzaris
Energy and climate policy officer - WWF Greece
E-mail: n.mantzaris@wwf.gr

www.wwf.gr/en

www.wwf.gr