THREE ESSAYS ON THE ECONOMICS OF RENEWABLE ENERGY IN SMALL ISLAND ECONOMIES

by

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Abstract

This thesis has studied three aspects of renewable energy integration in two small island states; Cyprus and Cape-Verde. In chapter 1, we introduce mechanism and present results of an integrated investment appraisal of an onshore wind farm for electricity generation that is owned and operated by a private investor. This model is applied to the situation in Santiago Island of Cape Verde. Such an appraisal is carried out to determine if the project will yield a high enough rate of return to be interest to a private investor while at the same time yielding a positive net economic present value from the perspective of the electric utility and economy of Cape-Verde. From the perspective of the electric utility and the economy, the results of such an ex-ante financial and economic appraisal of wind electricity generation depends critically on one's view of the expected long-term level of future fossil fuel prices, negotiations of the power purchase agreement (PPA) price and wind capacity factor.

In Chapter 2, we investigate the impacts of wind and solar renewable power sources on both electricity generation and planning by employing a cost minimization model including economic, technical as well as regulatory constraints. This model is applied to the situation in Cyprus. The cost minimization model demonstrates that the use of wind alone and mix of wind and solar power in an electricity generation mix reduces the overall cost of the system. Due to high cost of electricity generation from fuel oil in Cyprus, we conclude that shift toward wind and solar mix of energy sources in Cyprus will have significant impact by means of cost reduction. Therefore, integrating these renewables will essentially contribute to the welfare of Cypriot consumers alongside its environmental and health benefits associated in them. At the higher prices of fuel, the additional savings from wind, and wind and solar mix increase so that it can be seen as strong policy to hedging againts risk for fuel price fluctuations and increase.

In Chapter 3, we study the impacts of implementing real-time electricity pricing (RTP) in the Cypriot electricity market with and without wind/solar capacities. We particularly show impacts of RTP pricing on power prices, peak and off-peak capacities/energy, emissions from electricity generation and consumer bill savings. We use a merit order stack approach to generation investment and operation decisions. Empirical results show that dynamic pricing will increase generation capacity utilization by means of reduction in equilibrium installed capacity reduction and increase in load factors of off-peak plants. These savings are larger at higher demand elasticities. Because such dynamic pricing will allow consumers to pay lower prices for their energy consumption, it will however increase the total electricity generation. Therefore, the emissions from electricity generation will potentially increase resulting from increased energy consumption, however. Because wind (solar) availability comes mostly during low (high) demand hours when relatively cleaner (dirtier) plants operate in the system, we find that there is considerable potential for capital cost savings and emission savings from smart metering even with only a small consumer response and at moderate participation in the programme. At the current costs of solar, investing in wind alone will however yield higher bill savings.

I dedicate my accumulated education and efforts to produce this dissertation to:

all people who struggle in their lives due to any sort of abuse, conflict, discrimination, suppression and violence they faced or are still facing - regardless of their age, ethnicity, gender, sexual identity, income level, occupation…

all people who actively help/fight against abuse, conflict, discrimination, suppression and violence that happened or still happening towards others.

&

I also personally dedicate my thesis to a wonderful woman by the name of Lisa.

Justice for ALL

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INTRODUCTION

Overview

The combination of access to clean water, food, shelter, and energy services are part of basic human needs. Furthermore, access to these services should be available at an 'affordable' price and their supply should be 'reliable and 'clean' as they are fundamental for economic and social development. The educational, health and welfare benefits associated with access to affordable, reliable and clean energy services are substantial and the lack of these services often has adverse effects in terms of economic growth and development[1].

Although these statements are dogmatic, world energy access statistics are worrying and reveal that even access to energy services is not a right but still remains a privilege for some individuals in some parts of the world. For instance, the fraction of the world population still living in the dark and suffering from dirty cooking facilities[2] was high at 18.1% (1.258 billion people) and 40% (2.642 billion people) in 2011, respectively (World Energy Outlook, 2013). The main hallmarks of poverty in developing and less developed countries related to energy poverty are low electrification, insufficient installed capacity along with poor transmission and distribution infrastructure, lack of power supply reliability[3], high electricity production costs (leading to high prices)[4], and heavy reliance on traditional biomass use[5].

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[1] See studies by Karekezi, S., S. McDade, B. Boardman and J. Kimani, 2012: Chapter 2 - Energy, Poverty and Development. In Global Energy Assessment - Toward a Sustainable Future, Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Luxemburg, Austria, pp. 151-190.

[2] Traditional biomass use is widespread in Africa and developing Asia and it includes burning forestry wood and agricultural residues.

[3] As of February 2013, total capacity installed in Africa is 147 GW and it is equivalent to capacity installed in Belgium (AfDB Blogs, 18 February, 2013), and Modi, V., S. McDade, D. Lallement, and J. Saghir. 2006. Energy and the Millennium

Small island economies also suffer from similar problems. For instance, the majority of small islands have low electrification excluding developed small islands such as Cyprus and Malta in Europe, and Singapore in South East Asia, but almost all island states are heavily dependent on the import of fossil fuels for their energy needs, suffer from high electricity production costs due to the high transportation charges paid for fuel imports and diseconomies of scale in electricity generation (Monteiro Alves *et al.* 2000; Mayer 2000; Hatziargyriou, 2002; Weisser, 2004; Duic, 2004; Duic *et al.,* 2004; Woodruff, 2007; Segurado *et al.,* 2011), and face reliability problems in power supply due to insufficient installed capacity and/or having an isolated electricity system (Mayer, 2010; Antikainen *et al.,* 2009; Duic *et al.,* 2003)[6].Heavy reliance on petroleum products in the electricity sector makes it very expensive and at the same time difficult to guarantee the security of energy supply in small island states.

Small island economies have limited natural resource endowments, so their economic activities are limited and focussed mainly on service sectors such as tourism, education and financial services. The island electricity sectors are at the same time experiencing an increasing demand for energy mainly from domestic residential and tourism sectors, but suffer from an inability to supply energy to satisfy the increasing demand at low cost and in a reliable and environmentally friendly way. High electricity generation costs due to high oil prices, diseconomies of scale in electricity generation and heavy dependence on expensive fuel imports in turn negatively affects their competitiveness in the tourism sector, increases the share of household budgets allocated to

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Development Goals. New York: Energy Sector Management Assistance Program, United Nations Development Program, UN Millennium Project, and World Bank.

[4] See http://www.afdb.org/en/blogs/afdb-championing-inclusive-growth-across-africa/post/the-high-cost-of-electricity-generation-in-africa-11496/

[5] See World Energy Outlook 2006 – Focus on Key Topics, Chapter 15 - Energy for Cooking in Developing Countries, 2006.

[6] For example, half of the Cypriot island's generation capacity was lost from the Vasilikos power plant disaster on July 2011. Estimated total damage to the Cypriot economy was more than €3 billion, equivalent to 15% of GDP in that year (Bloomberg, 2012). The high loss of national income from the explosion is mainly due to coinciding with the summer energy load when demand for electricity is highest, so this disaster hit the island's finance and tourism sector.

energy bills and increases fuel payments on fuel imports. The argument is therefore that conventional electricity generation from fossil fuels creates economic and financial vulnerabilities and difficulties for households, businesses and national governments. Hence, a supply of affordable, reliable and clean electricity is indispensable for their economic transformation (e.g. Cape Verde) as well as to sustain the level of economic growth (e.g. Cyprus) in the long-run. The key challenge in an island's power sector is therefore to address the energy problems in a way to boost energy access and supply energy services at an affordable price and reliably by arranging the portfolio mix of generation technologies and fuel mix[7].

Given the abundance of various renewable energy resources in island countries, movement toward a green economy seems to offer a gateway to deal with energy challenges in island economies. The idea of increasing the renewable share in electricity generation and facilitating the integration of renewables into the system receives significant political support by means of enforcement of green regulations and financial incentives that govern market access to renewable energy sources in island countries (Chen, 2007; Weisser, 2004; Garcia and Meisen, 2008)[8]. Counting emission reduction benefits alongside the energy security (fuel supply) risk-reducing and self-sufficient power generation properties of renewable technologies have resulted in support granted to RES investments in island countries as their power system is isolated (Maxoulis and Kalogirou, 2008) and abundant of various renewable energy resources exist including wind and solar (Weisser, 2003; Chen et *al.,* 2007).

Energy related problems of small island states are linked to providing clean and sustainable energy in a cost–effective manner whilst maintaining system reliability in terms of both energy

[7] See Moss and Leo (2014), Shaalan, H.E. (2003), Joskow (2010)

[8] Although we will not discuss the pros and cons of renewable incentive programs here, renewable power incentives such as guaranteed prices or say FITs schemes in Europe is based on energy output of particular renewable energy source but not on the amount of CO_2 emissions reduction by the renewable energy source. This is quite different to carbon pricing paid by "dirty" power sources, for example carbon pricing is not biased toward any technology and kwh of carbon payments depend on carbon intensity of the fuel to generate kwh of energy.

security and energy adequacy. Among all renewable energy sources, the focus of this research will be on the economics of wind and solar energy which are the two main indigenous forms of renewable energy sources in island economies.

Motivations and Goals of Research

In the past, investment decisions in electricity generation technologies were largely driven by their capital costs and fuel prices such as fuel oil, coal, and gas. The current perception is that electricity generation from fossil fuels is relatively cheaper than that from renewables. Therefore, in the absence of stringent environmental interventions (i.e. neglecting social costs of electricity generation) to establish a price for emission of pollutants and green tariffs to promote renewable energy technologies, the outcome might be the large expansion in capacity of less environmentally friendly fuels such as coal and fuel oil.[9] This means that emissions of environmentally harmful substances from electricity generation are bound to increase with conventional electricity generation although the supply of electricity comes at relatively lower cost. Utilities are still experimenting in order better to understand and assess the "true" costs and benefits of renewables based on renewable investments in different countries.

It is well recognised and established that both the timing and scaling (and location) of power production determines its benefits and costs. The expected return from renewable investments is to generate electricity economically and in an environmentally sustainable way while securing the energy supply. But aggressive renewable energy policies and financing instruments intended to increase the share of renewables in the energy mix and reduce emissions from these sources might come with high compliance costs that adversely impact on the economy as a whole (Peters *et al.,* 2012; Hoppmann, 2013). Today, developed and developing island economies' desire to shift

[9] See *The Economist*, 22 September 2014, % of GDP lost from coal generators; approximately 11% to Chinese economy, 8% to Russian economy, 6% to German economy, and 4% to UK and US economies. http://www.economist.com/blogs/graphicdetail/2014/09/daily-chart-17?fsrc=scn/fb/wl/dc/priceofexposure

towards renewable energy sources (as outlined above) also result in public interventions to attract investments in renewables in the form of guaranteed tariffs, renewable targets etc.

The main motivation of this research is to study the various economic impacts of grid-connected renewables on vulnerable island economies. Pointing out the key results from each chapter, we suggest a menu of public instruments to facilitate the operations of the power market successfully via investments in power generation technologies and improved pricing of electricity. It is hoped that this research can contribute better understanding and better energy policies while trying to propel their economies toward sustainability.

Outline and Summary of Research Chapters

Before proceeding to the outline of the research, we summarize the following limitations of this research: (1) the supply of renewable energy is deterministic[10] (2) there are no transmission constraints and we assume the integration of renewable energy into the national grid is successful, (3) unquantifiable and non-monetized benefits and costs such as avoided health benefits and net employment change from renewables are excluded, (4) we ignore renewables that are not grid-connected. The other assumptions relating to each study are presented within the substantive chapters. This research is organized as follows.

In chapter one, we analyse the distributions of potential benefits and costs realized from grid-connected wind investment. It is conceptually wrong to state whether renewable investments are good or bad without allocating the benefits generated and costs incurred from any renewable source of electricity generation. To correctly investigate the distributional impacts of wind power

[10] Wind speed (solar irradiation) is a random outcome so that the energy from wind (solar) generators is estimated from the wind speed (solar irradiation) probabilities in a construction site at each hour of the day. The stochastic nature of the relationship of wind power (solar power) to wind speed (solar irradiation level) is not modeled in this research, however. Examples of such analysis stochastic long-term planning models include, for example, Fürsch, *et al.* (2012), Nagl *et al* (2012).

investment by private investors, the mechanism in this chapter draws a strict line between financial returns (monetary value of private benefits) and economic returns (monetary value of public benefits) when evaluating such investments. The research in this chapter is applied to Santiago Island of Cape-Verde, but can be applied to any grid-connected wind investment in any other country with an isolated power system where such investments are made by the private sector. To our knowledge, such a distribution-based impact assessment is yet to be carried out for this type of energy investment.

This appraisal is carried out to determine if the project will yield a high enough rate of return to be of interest to a private investor, while at the same time yielding a positive net economic present value from the perspective of the country. From the viewpoint of the electric utility and the economy, the results of such an ex-ante financial and economic appraisal of wind electricity generation depends critically on one's view of the expected long-term level of future fossil fuel prices, fuel-oil matrix, wind capacity factor and negotiations of the power purchase agreement (PPA contract price) price for wind energy.

In chapter two, we try to quantify the impacts of wind and solar power penetration on electricity expansion and generation in Cyprus by including regulatory constraints such as a renewable energy target and emission targets. In this way we can capture the economic costs of these regulatory constraints on the electricity sector and test whether green regulations are cost-effective means to reduce emissions and achieve mandatory EU renewable targets while protecting consumers from high prices. In order to do this, wind and solar sources are brought into a supply system alongside generation from conventional plants. We initially build a theoretical model where the objective is to minimize the weighted sum of economic cost and the monetised value of pollutant emissions from electricity generation given a set of supply constraints. We apply this model to assess the economic and environmental impacts of integrating wind and solar power in the Cypriot power supply system. The model presented in this paper can be applied to any isolated power system with similar national renewable and emission reduction targets. To our knowledge, such an impact analysis is yet to be explored for Cyprus.

To anticipate the results somewhat, given the fact that solar power is currently an expensive source of electricity generation, solar power will probably not be integrated in the national grid in the near future. Current public policies in promoting renewables in the form of taxes and other policy measures might impair the system by relying on large volumes of wind alone in the thermal-renewable generation mix. These conclusions are based on the assumption that consumers will pay fixed regulated tariffs for their energy consumption. From an empirical analysis, we suggest that it is not yet the right time to shift to renewable energy sources in Cyprus and it is better to postpone such capital-intensive investments in electricity generation based on the expectation that Cyprus will move from regulated tariffs to time-varying energy pricing and will be able to ultimately include natural gas in its supply mix.

In chapter 3, we analyse the potential impacts of implementing real time pricing (RTP) of electricity on the need for long-run capacity, on total demand, on renewable energy sources such as wind and solar, on emissions, on prices, and on consumer bills. The existing literature shows that the application of RTP or near-real time (e.g. time-of-day pricing, TOU; critical peak pricing, CPP) retail pricing promises to reduce/postpone peak demand investments, enhance reliability in the system, lower the costs of generation (i.e. prices), and facilitate the integration of renewable sources of electricity – which are also major concerns for island economies. We present results for the Cypriot electricity market considering the characteristics of the market assuming that wind and solar sources of power are both constrained. To our knowledge, such screening of impacts from implementing dynamic pricing of electricity has yet to be explored for Cyprus. The model presented in this paper can be applied to any isolated power system with a similar radical objective of moving towards RTP in the electricity market. We adopt a constant elasticity demand function and then follow an optimal stacking approach to generation investment and operation decisions. In this approach, a system planner minimizes the total cost of power supply but without charging long-run system marginal costs to consumers as the RTP program itself implies marginal cost pricing principle. We present impacts of RTP on total capacities (MW), energy consumption (MWh), capacities (MW), emissions (tonnes), fixed and demand-weighted prices (€/MWh) and consumer welfare (€).

We also compare results from RTP programs with and without renewables (wind and solar in this case) in order to understand the implications of RTP in the conventional system alone and implications of RTP with wind/solar integration. In 2010, neither wind nor solar sources of electricity generations were included in the system. Therefore, the analysis with renewables is used to assess their future potential impacts on prices, capacities, emissions and consumer bills that potentially will help us to understand their implications for the system and on customers when both wind/solar are included in the system in 2020 or shortly after.

Based on empirical results, we find that dynamic pricing will increase utilisation of existing installed capacity, and will reduce the need for peaking plants resulting in savings in capacity dependent on the customer response. However, because real-time pricing will lower energy prices, total electricity generation will increase. The immediate implication of this is an increase in emissions from electricity generation. With respect to consumer bills, we find that both fixed and RTP customers are better-off by means of lower energy bills. They will pay for additional energy in comparison to fixed regulated pricing of electricity. Because wind (solar) availability coincides with low (high) demand hours when relatively cleaner (dirtier) plants operate in the system, we find that there is greater potential for capital cost savings and emission savings, but not necessarily energy cost savings from smart metering even with only a small consumer response, and/or with moderate participation in the programme (i.e. 50% of total customers). At the current costs of solar, wind alone will yield lower bills.

In the final concluding chapter, we summarize the results of each preceding chapter and discuss the key policy implications based on our findings. Lastly, we identify what other research questions emerge out of this exercise and which are ripe for further investigation.

CHAPTER 1: IS WIND GENERATION A GOOD INVESTMENT FOR CAPE-VERDE?

1.1. Introduction

The limited availability of exhaustible natural resources, rapidly growing demand for electricity and increase in greenhouse gas emissions from electricity generation have caused many policymakers to propose that any increase in the supply of electricity be generated from renewable power sources. The reasons for the increasing trend towards investment in renewable resources are mainly attributed to their perceived unlimited availability, low operating costs and nature as sources of electric energy that are emission free (Murray, 2009)[11]. At the same time, the implementation of various renewable support programs by governments is accelerating the deployment of renewable energy technologies, for example renewable energy targets, the emissions trading system (ETS), and Feed-in-tariff (FITs) in Europe. In addition, as the market for wind and solar has grown, so the costs per kWh have reduced drastically. As a result, increased penetration of wind and solar energy continues in electricity networks. Given the optimistic national targets for renewable electricity generation, for example in Europe, an active debate exists on the advantages and disadvantages associated with renewables. Meanwhile, global wind power development is experiencing dramatic growth with an increase in global installed capacity from 18 GW at the end of 2000 to 240 GW at the end of 2011 (IEA, 2013).

[11] Renewable sources of power supply may produce some negative externalities such as noise pollution, land deterioration and bird kills associated with wind farms, all being non-market environmental goods. Note that these costs are not the same across the renewable technologies. These negative externalities are excluded in our analysis, but these affect the public perception and might create resistance toward these investments (Bergman and Hanley, 2012; Toke *et al.,* 2008; Alvarez-Farizo and Hanley, 2002; Krohn and Damborg, 1999). Compared to conventional electricity generation technologies, for instance, wind is relatively clean and has less negative environmental impacts than others (Sundqvist, 2002).

Foreign or local independent power producers (IPP) started selling electricity under long-term contracts with state owned electric utilities in Africa in the early 1990s (Gratwick and Eberhad, 2008; Woodhouse, 2005; Oliveira *et al.,* 2005). This is a first step toward the establishment of joint ventures - state majority ownership of generation in collaboration with private investors (i.e. independent power producers). The electric utilities in Africa signed power purchase agreements (PPA) with private suppliers (or IPPs) to build power plants as the first step towards reforming their less efficient electricity sector[12]. The motivations for this gradual movement are as follows: electricity investments are highly capital intensive but public electricity utilities in Africa are capital-rationed, the electrification rate in sub-Saharan Africa is very low, while almost all governments are constrained in their ability to borrow to expand the electricity capacity to meet the increased demand for energy even for existing connections, and the absence of reliable and efficient electricity supply limits their economic and social development (Albouy and Bousba, 1998; Turkson and Wohlgemuth, 2000; Bacon and Jones, 2001; Gratwick and Eberhad, 2008).

The private renewable power investors often sign long term power purchase agreements based only on the amount of electricity delivered to the public utilities which allows them to earn a rate of return from invested capital in exchange for power purchased by the public electric utility. The

[12] This transition in Africa appears to be very problematical, however. Public-Private Partnership (PPP) electricity projects in Africa might not be effective and efficient due to corruption (World Bank, 2009; Karekezi and Kimani, 2002), over-estimation in stated capital costs in IPPs investments (Phadke, 2009), and IPPs willingness to invest in low capital cost plants (fuel is often supplied by the state owned utilities) - possibly to meet high debt ratios set by the banks, and cover the political risks associated in their power purchase contracts[12].Therefore, consumers might end-up paying higher electricity prices for low investment cost but high generation cost plants, while private investors might earn more than "fair" returns even on their low investment cost plants. Thus, poor institutions, lack of legal capacity, and lack of competitive bidding mechanisms on IPP investments in Africa all create conflict rent seeking in the sector and imprudent investments in the sector. That is why, regulatory arrangements together with improved institutional and legal capacity are necessary to achieve equilibrium in regulations and improve efficiency in the sector (Jamasb, 2006; Phadke, 2009; Eberhard, 2011). For more information on IPPs in building infrastructure capacity in African countries, see studies by Worch *et al.,* (2013), "A capability perspective on performance deficiencies in utility firms", *Utilities Policy* , 25:1-9, Eberhard, A. and Gratwick, K. (2013), "Investment Power in Africa, Where from and where to?*", Georgetown Journal of International Affairs*, The Future of Energy 14.1 :39-46, and Karekezi, S., and Kimani, J. (2002), "Status of Power Sector Reform in Africa: Impact on the Poor", Energy Policy, 30(11-12):923-945. Also, see Vecchi *et al.* (2013) similar problems in developed countries, "Does the private sector receive an excessive return from investments in health care infrastructure projects? Evidence from the UK", *Health Policy*, 110 (2-3):243-270.

long – term PPA contract is a key element for the development of the wind energy sector. Such a rigid long term agreement (depending on its terms) would be highly risky for thermal generators that must deal with fluctuating fuel prices. Such an agreement, however, is highly compatible with the operation of wind farms because their costs are mainly the up-front investment costs. In this chapter, we investigate the impacts of adding large-scale wind power in Santiago, Cape Verde that is supplied by a foreign owned IPP where the public electric utility signs a long-term take or pay PPA with the IPP. With the completion of the wind project, the private IPP added 9.35 MW of wind capacity to the existing system, and the electricity electric utility in Santiago, Cape Verde is the off-taker of the generated wind electricity.

Existing studies in the literature define the social cost of wind integration as the private costs of wind electricity generation net of the avoided fuel and environmental costs enabled by the facility (e.g. Kennedy, 2005; Denny and O'Malley, 2007). This study goes further and allocates the benefits and costs of wind electricity generation amongst the different stakeholders of the project based on the PPA. This analysis is useful as the role of the private sector in undertaking power projects including renewable projects has greatly increased over time (Meyer, 1998; Martinot, 2001; Weisser, 2004; Phadke, 2009; World Bank, 2013)[13]. To our knowledge, such an impact assessment is yet to be carried out for this type of energy investment.

High costs of electricity generation – yet unable to cover the high costs of electricity generation with imported petroleum products, and unreliable power supply are burden on the economy of the Cape-Verde (IMF, 2013)[14]. With the aim of reducing energy costs, and ability to reliably meet

[13] Also see World Bank Database for Private Participation in Infrastructure Database, including investments in electricity sector. Up to date country data is available at: http://ppi.worldbank.org/resources/ppi_glossary.aspx

[14] Cape-Verde uses two-block "increased block tariff" for the customers. The retail electricity tariff for block 1 consumers (consumption <=60,000 kWh/month) is 30 CVE/kWh equivalent of 0.27 Euro/kWh and the retail electricity tariff for block 2 consumers (consumption >60,000 kWh/month) is 37.89 CVE/kWh equivalent of 0.34 Euro/kWh (See, Economic Regulatory Agency of Cape-Verde: http://www.are.cv/index.php?option=com_docman&task=cat_view&gid=51&limit=5&limitstart=0&order=date&dir=DESC&Itemid=111).

both current and future demand for energy, the Government of Cape-Verde sets ambitious targets for the contribution of renewable electricity generation about 50 percent of total electricity required in 2020 solely through private sector investments (ECOWAS Centre for Renewable Energy and Energy Efficiency, *ECREEE*, n.d.; European Commission, February 2014). In this context, it is interesting to set-up a model for Cape-Verde that can help regulatory bodies to improve long-term power purchase contracts by means of achieving the renewable policy objectives at the lowest cost possible – especially when considering the conflict of interests between the electric utility/economy of Cape-Verde and private power supplier. Due to high cost of solar PV for electricity generation and high cost of off-grid wind electricity generation, the emphasis is put on the economics of the grid-connected onshore wind source of electricity generation[15,16].

The contribution of this paper is two-fold: the focus of this paper is first to provide a mechanism to draw a strict line between economic analysis and financial analysis or public benefits and private benefits when evaluating the welfare changes from renewable electricity generation when the private sector is involved in such investments. The second objective is to evaluate the viability of on-shore grid-connected wind turbine installations from the perspectives of the different market players including the public electric utility, the private investor, the country and local government[17]. Each of these stakeholders is affected differently by the proposed wind power installation. And, usually a country-specific electricity system analysis is required in order accurately to assess the costs and benefits of the integration of a renewable electricity generation

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[15] Also see, Jensen (2000), Renewable Energy on Small Islands, available at http://www.gdrc.org/oceans/Small-Islands-II.pdf and Food and Agriculture Organisation of the UN, see full report at http://www.fao.org/docrep/014/i2345e/i2345e05.pdf

[16] Note that land based wind investment are called as on-shore wind and ocean (sea) based wind investments are called as off-shore wind. Krohn *et al* (2009) state that the capital costs of offshore wind capacity is still about 50% more than onshore wind and its applications are predominantly in northern Europe (e.g. UK, Denmark, and the Netherland).

[17] Reduction in CO_2 emissions and the extraordinarily high profits of foreign investors are benefits to the world rather than only to the country where the renewable project is actually undertaken.

facility into a larger electricity system. Wind energy is capital intensive in nature and the life time of the wind turbine is approximately 20 years[18] (Mills *et al.,* 2009). Thus, a twenty-year net cash (resource) flow statement is prepared for each of these stakeholders. The costs and benefits of the integration of wind power generation into the island's electricity grid are evaluated for a period of 20 years. Since all the future benefits and costs must be expressed in the price level of a given year, the nominal values of the cash or resource flows are deflated to the 2010 price level and present values are calculated for each interest group by applying the relevant discount rate(s). Hence, the integrated appraisal framework allows us to determine who picks up the benefits and costs of this wind electricity investment by the private IPP. Because each economic actor pays and receives different costs and benefits from any economic activity including the investments on renewable power generation, this framework also allows re-distribution of these benefits and costs from such investments. In this way, regulators can link renewable energy investments and relevant energy policies in such a way as to benefit both the economy and utilities while allowing private investors to earn a fair return on their investment.

1.2. Literature

The capital investment costs of the grid-connected onshore wind farm are composed of i) capital equipment cost (wind turbine) accounting for between 68% and 75% of the total cost, ii) grid-connection/cabling costs (transformers, sub-stations, connection to transmission and distribution lines) iii) cost of civil work (transportation and installation of wind turbine and tower, road construction, construction of wind turbine foundation) iv) other capital costs (licensing, consultancy, permits, financing costs) which all accounting for the rest of total cost (Blanco, 2009; Krohn *et al.,* 2009; Tegen, 2012)[19]. The annual operation and maintenance costs (insurance, taxes, spare parts, management and administration) are not as well-known as capital costs and

[18] See www.worldsteel.org/pictures/programfiles/Wind%20energy%20case%20study.pdf
[19] Note that there are two types of wind energy generation; land based wind investment are called as on-shore wind and ocean (sea) based wind investments are called as off-shore wind.

usually constituting less than 5% of total investment costs (Krohn *et al.,* 2009; Blanco, 2009). The shares of different capital cost components of wind farm varies by project and where the project is being developed, however. For example, the cost of the grid integration vary significantly between projects as these costs depend on further system network improvements and transmission upgrade needed to connect wind farms to the grid, remoteness (distance) of wind farm from the network (Krohm *et al.,* 2009; Tegen, 2012). In addition, the kWh of wind costs cannot be identical in every region or country since kWh of energy vary depending on wind conditions of the site and type of wind technology such as its height, rotor diameter and MW size of wind turbines, (Mills *et al,* 2009; Tegen, 2012; National Renewable Energy Laboratory , NREL, 2011).

Since most renewables are intermittent, they cannot be turned on and off with changing demand for electricity. Therefore, the economic value of renewable power depends on location and the hours when the renewable plant replaces the generation of electricity by thermal plants. The gross economic benefits are the total value of savings in fuel costs, fixed costs savings, capacity savings from adding renewable plant in the longer-term if its output coincides with the system peak-load and environmental benefits in the form of averted pollutant emissions. To start with, to achieve these savings from wind power generation, the rest of the generation system must be flexible enough to cope with the renewable power variability (Lund and Munster, 2003; Lund, 2005; Denholm and Han, 2011)[20].

Benefits from a typical renewable power project are the stabilization of electricity costs (perhaps at a high level), fuel cost savings (Jensen and Skytte, 2003; Bode, 2006; Sensfuß *et al.,* 2008; De

[20] In regions of the country where shortage in capacity occurs and/or the system is not flexible enough to cope with the intermittent energy sources, some of these benefits such as fuel and capacity savings cannot be realized. At the same time, these economic and environmental benefits are not attributed to wind and/or solar capacity investments only as they are realizable by any source of power generation technology with a lower marginal cost of generation which would also yield the same economic and environmental benefits but at different amounts.

Miera *et al.,* 2008; Butler and Neuhoff, 2008; Weigt, 2008; Lamont, 2008)[21] and the reduction of pollutant emissions from conventional electricity generation (Sims *et al.* 2003; Lund, 2004; Kennedy, 2005; Doherty and O'Malley, 2006; Delarue *et al.* 2009; Akella *et al.,* 2009; Tsilingiridis *et al.,* 2011). Therefore, it can be economically and environmentally desirable to feed renewables into the system.

Electric power generated from most renewable sources is intermittent (variable) and non-dispatchable. Because a large amount of elective power cannot be economically stored[22], increasing the renewable sources of energy supply threatens the reliability of electricity generation systems because these energy sources fluctuate over time (Holttinen and Hirvoven, 2005; Karki *et al.,* 2006). Because of this characteristic, a high level of penetration of renewable electricity generation technologies may create serious reliability problems in the power system supply (Holttinen and Hirvoven, 2005; Doherty and O'Malley, 2005; DeCarolis and Keith, 2005; Karki and Billinton, 2004; Smith *et al.,* 2009, Boqiang and Chuanwen, 2009). In order to overcome this reliability problem with non-dispatchable renewables, utilities must keep additional reserves so that they can maintain the system reliability[23].

In this regard, the net benefits of the renewables should be estimated as the savings in fuel and carbon emissions, but after subtracting out the additional reliability costs (Strbac *et al.,* 2007; Smith *et al.,* 2004)[24]. In other words, while wind and solar energy sources save significant amounts of fuel from displacing power produced by conventional power generators, these sources cannot

[21] Some authors strongly disagree on this, for example Etherington (2006) and Traber and Kemfert (2009).
[22] In the literature, energy storage technologies and the decentralizing of the wind farms are suggested as being solutions to problems associated with renewables. However, electric energy storage is not yet cost-effective. Decentralized wind farms require massive investments in transmission that may substantially reduce the benefits of wind. Therefore, to date none of these options are cost-effective.
[23]In this analysis, we use reliability costs estimates from the literature so that we do not underestimate the results presented for public utility's point of view and country-economy point of view.
[24]Also see Munksgaard and Larsen (1998) and Bergmann *et al.,* (2006) for external costs to determine social and environmental impacts of adding renewable in the system.

displace the capacity of conventional generating power units on a megawatt for megawatt basis[25]. As a consequence, renewable sources are limited in their substitutability for conventional thermal generators and cannot meet the entire demand for energy due to their uncontrollable variability. In fact, the capacity credit of wind or any other type of renewable shows that it is not a MW by MW substitute for conventional generation due to reliability concerns. And, this is valid for any type of electric utility if it faces power outages and power reliability problems in its supply system such as those in the islands of Cape Verde, and North Cyprus[26]. For example, a World Bank (2011) study for Cape-Verde suggests that wind-based sources of electricity generation will not provide firm generation capacity in Santiago Island of Cape-Verde, so that the integration of wind will not bring any reduction in thermal capital expenditures in Cape-Verde (World Bank, 2011, p. 9). Although the WB report did not specify the reasons for this, it is likely because Santiago System is in the process of rehabilitation in terms of generation, transmission and distribution of electricity, whilst local government is planning to shut-down decentralized diesel-oil generators and planning to expand the island network into single node while investing in fuel-oil diesel plants (World Bank, 2011).

Literature since the late 1970s argues that wind power is a feasible option in supplying the power in isolated islands where high winds are observed (Daviatian, 1978; Wright, 2001). The main reason is that diesel and gas turbines are usually used to generate electricity and that these plants

[25]Also see Lamont (2008), Bushnell (2010), and Green and Vasilakos (2010) for the impacts of wind on prices and capacities.

[26] Electric utilities in many developing countries (as well as developing and developed island countries including Cape Verde and Cyprus) also fail to provide reliable and adequate power supply to its existing residential, commercial and industrial connections. What is more, unreliable electricity supply from electric utilities has been cited as the major constraint to the businesses to operate in these countries and costs to the firms in terms of lost sales revenues and damage of physical capital from frequent outages (Oseni and Pollitt, 2012; Foster and Steinbuks, 2009). Therefore, firms take expensive precautions to cope with unreliable power supply by operating their own generation. This means that firms spend capital on self-generation plus the high marginal cost of generating electricity compared to kWh purchased from public grid as diesel fuel is mostly used to generate electricity from self-generations (Foster and Steinbuks, 2009). According to World Bank (2009, p. 19) survey data, the average cost of self-generated electricity is significantly higher than the actual cost of electricity supplied from the public grid. These averting expenditures results from unreliable power supply have not only direct implications for firms' profits but also costs to their economies as the capital might be used in other productive investments otherwise. This is translated into loss of incomes as well as a loss of jobs.

are expensive in terms of oil consumption and have low efficiency, for example in Cape Verde. Some studies suggest that an isolated island power system, for example, Cape Verde, with no oil or gas pipeline interconnections and no electricity interconnections with other countries might need to keep larger spinning reserves due to lack of interconnection; and with an increase in intermittent source of power supply in generation mix, the amount of spinning reserves should be even larger to guarantee grid reliability, alternatively conventional power production to maintain grid reliability should increase as long as wind power penetration increases (Mayer, 2000; Karki and Billinton, 2001; Fesquet *et al.,* 2003). Hence, we can conclude that wind-based power supply cannot meet the entire load demand in island power systems.

Previous studies showed that high wind integration in the Island of Santiago's power supply sounded economically viable. For example, Cabral et al. (2009) argue that 5.1 MW grid-connected utility scale wind capacity integration will enhance grid reliability in the form of a reduction in both active and reactive losses by 24.88% and 13.83% during peak hours and 12.41% and 12.65% during off-peak hours. Based on capital cost estimates of wind farms, they conclude that wind investment is good investment for Cape-Verde, but two potential problems in their study are: (i) they estimate cost savings in the form of loss reductions net of total wind investment costs assuming that the utility invests in wind projects and (ii) wind investment capital costs are assumed to be $1.1 million per MW of wind capacity, which is much lower than the actual capital costs associated with onshore wind investment.

Norgard and Fonseca (2009) study the technical utilization of grid-connected utility scale wind integration in the energy systems of Cape-Verde islands as function of the wind capacity. Based on their technical study and the characteristics of the energy system in Santiago Island, they argue that the penetration of wind capacity – at least up to 21% is possible – so wind-based output will be successfully produced and transmitted without any losses. They further conclude that the avoided fuel savings from diesel plants alone can justify the installation of wind farms in Cape-Verde including Santiago Island. These studies, however, do not analyse and study the feasibility of grid-connected renewables with private sector participation in the electricity sector via independent power producers (IPPs) type electricity generation projects as is the case in Cape-Verde. Therefore, they do not take into account system supply and demand conditions while evaluating the economic feasibility of such investments.

1.3. Electricity System in Santiago Island of Cape-Verde

Cape Verde has a population of 494,401 spread over ten islands where half of the Cape Verdeans live on Santiago Island (World Bank, 2012). As of 2010, the nominal GDP per capita in Cape Verde has reached $3,798 (World Bank, 2012). It is expected that increasing population growth, the expansion of the service sectors including real estate, tourism development and increased production of desalinated water will create strong growth in the demand for electricity. The frequent black-outs due to the capacity deficit together with extremely high energy losses due to low infrastructure facilities however, constitute a critical barrier to sustaining higher economic growth. Hence, high fuel prices to generate electricity reflected in electricity tariffs, increasing capacity to meet the projected demand and chronic power supply reliability are the main challenges of the electric utility company in Santiago Island of Cape Verde. The government in Cape Verde aims to meet the rapidly rising demand for power in Cape Verde in an environmentally friendly and cost-efficient manner.

At the same time, unreliable electricity supply from electric utilities has been cited as the major constraint to the businesses trying to operate in African countries including Cape Verde and costs to the firms in terms of lost sales revenues and damage to physical capital from frequent outages (Oseni and Pollitt, 2012; Foster and Steinbuks, 2009). Therefore, firms have to take expensive precautions to cope with unreliable power supply by generating their own electricity. This means that firms spend capital charges on self-generation plus the high marginal cost of generating electricity compared to kWh purchased from the public grid as diesel fuel is mostly used by private agents to generate electricity (Foster and Steinbuks, 2009).

According to World Bank survey data, the average cost of self-generated electricity in Cape-Verde is significantly higher than the actual cost of electricity supplied from the public grid. These averting expenditures resulting from unreliable power supply have not only direct implications for firms' profits but also costs to their economies as the capital might be used in other productive investments. This is translated into a loss of incomes as well as a loss of jobs. In addition to this, ELECTRA, the electric and water utility in Cape Verde bear hidden costs in the power sector. These hidden costs include distributional losses, under-pricing and uncollected energy costs and accounted for approximately 2% of the country's GDP (Briceño-Garmendia and Benitez, 2010). This means that cost recovery by ELECTRA does not reach 100% and result in financial deterioration in its capital assets.

Abstracting from any positive rate of return on capital, the regulated electricity tariff is even less than the break-even price – that is the price for revenue collection is less than the cost-recovery price for operations and capital depreciation so ELECTRA incurs a deficit in its power supply. This simply means that ELECTRA's return on capital is even negative and ELECTRA's operations are mostly financed with debt. The reasons for this are: (i) regulators consider the efficient level of energy losses for the tariff-setting that is less than the actually reported energy losses by ELECTRA, (ii) ELECTRA's poor level of revenue collection from billed electricity sales and (iii) very high losses in transmission and distribution of electricity (World Bank, 2011; IMF, 2008). In addition, the World Bank report (2011, p.7) actually stated that both disagreements over tariff adjustments and poor long-term investment planning in the sector were the major reasons for the failure of the privatization of ELECTRA in Cape-Verde.

Figure 1.1. Santiago Island of Cape-Verde Energy Network[27]

[27] The author has drawn both transmission and distribution lines as straight lines, although they depend on the landscape. This map is subject to change with time as energy sector projects are on-going in Santiago Island of Cape-Verde. This map has been based on information publicly provided from the following sources: (1) http://www.ecreee.org/sites/default/files/unido-ecreee_report_on_cape_verde.pdf; Annex F6 – 8 (page 17), (2) http://www.afdb.org/en/news-and-events/article/santiago-production-capacity-and-distribution-network-strengthening-project-6625/ (published on 27/04/2010, accessed on 20 October 2014), (3) http://www.electra.cv/novo/INVITATION%20FOR%20BIDS.pdf, pages 1-2, (5) Regulatory papers by ELECTRA, available at http://www.electra.cv/index.php/Relatorios/View-category.html
(6) World Bank, December 2011, Project Appraisal for a Recovery and Reform of the Electricity Sector Project in Cape-Verde.

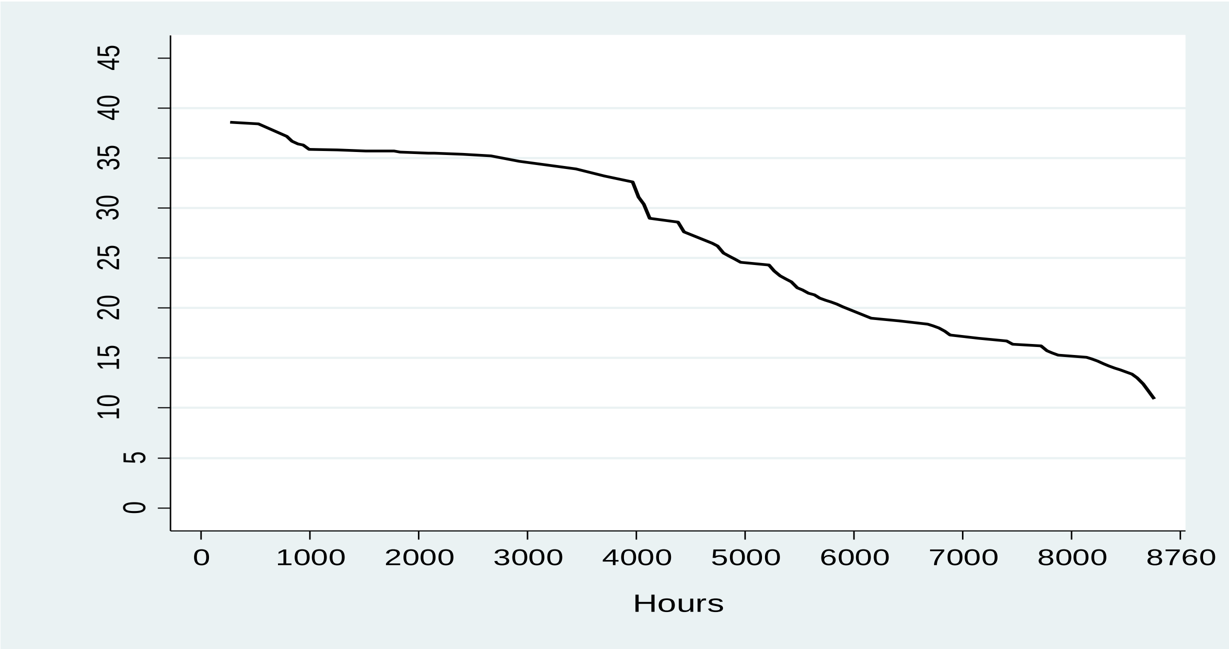
Therefore, Cape-Verde's energy problems were ultimately due to massive institutional and governance failure (i.e. regulations) which led to imprudent and reckless energy policies, poor long-term investment planning in the sector and failure of the privatization of ELECTRA in Cape-Verde. In order to solve the energy problems outlined above, the government of Cape-Verde placed its faith in long-term investment planning in generation, transmission and distribution of electricity. The national government with aid from international organizations (e.g. World Bank) and regional banks (e.g. African Development Bank) has been implementing a series of rehabilitation projects in the sector. As part of those rehabilitation investments in generation, an increase in renewables (mostly on-shore grid-connected wind investments) was perceived as part of the diversification of the energy supply that potentially reduced the thermal generation costs, and which could stabilize the electricity tariff from variation of oil prices.

The plans also foresaw an increase in the reliability in power supply by means of reduction in energy losses and reduction in frequency of blackouts. Alongside investments in renewables and the use of inexpensive fuel in power supply (shifting from heavy fuel oil -HFO 180 to heavy fuel oil – HFO 380), projects to extend the transmission lines to isolated loads were considered wherever possible in order to increase the potential for fuel switching as isolated loads run with expensive and dirty diesel generators (World Bank, 2011). These investments in generation, transmission and distribution of power supply will eventually allow ELECTRA to take advantage of economies of scale in its operation with a single centralized power station.

1.3.1 Demand for Electricity in Santiago Island

The demand for electric generation for the year of 2010 is presented in figure 1.2. In the figure below, the total 8760 hours in a year are plotted on the x-axis while the demand for capacity in MW is ranked on the y-axis. For instance, the baseload demand for electricity in the island is about 10 MW which must be supplied 24 hours a day continuously. The amount of electricity that falls into the extreme peak load time is about 40 MW that must be supplied over only 261 hours a year.

Figure 1.2 Annual Load Duration Curve of Santiago Island as of 2010



Source: Reproduced from data supplied by *Simonsen Associados* (February 2008)

Demand for electricity is an exogenous variable in our analysis. Using Santiago's historical annual demand for electric energy in the year 2006 and a subsequent demand study for the island prepared for ELECTRA by *Simonsen Associados* (February 2008), the annual projected load duration curves from 2010 to 2031 are produced for the island. Based on demand studies available to the public, we projected the demand for electricity such that there is a 15.5% annual increase from 2007-2012, a 6.25% annual increase from 2013 to 2017, a 5% annual increase from 2018-2022, a 4.75% annual increase from 2023-2027 and lastly a 4.5% annual increase from 2028 to 2031.

1.3.2 Supply of Electricity

Power plants differ in terms of costs they incur for an additional MWh of electricity generation because each technology requires a different type and amount of fuel plus non-fuel operating costs (O&M) to produce a unit of electricity. Demand for electricity is met from a heterogeneous mix of power plants, so the marginal cost of power supply varies throughout day. Santiago Island has its own isolated electricity supply system. The existing power supply mix of the island in the year 2010 includes those generators running with fuel oil and diesel oil. ELECTRA is the electricity authority of Cape-Verde responsible for the generation, transmission and distribution of electricity in all islands including Santiago Island of Cape-Verde.

Santiago Island of Cape Verde has some of the highest transportation costs for fuels of any jurisdiction in the world. For instance, the domestic fuel oil costs for electricity generation are about 150% of the world price due to transportation costs and taxes, and might also come from low demand for fossil fuel imports and additional transportation charges paid on fuel transport as the energy systems in Cape-Verde split into independent island energy system.[28] The power supply characteristics of the existing system is provided in Table 1.1 with each power plant's year of establishment (t), kW available capacity, type of fuel and amount of fuel oil requirements to generate each kWh of electric output. As expected, the generation plants are heterogeneous so the operating costs and emissions from individual power plants at each kWh of electricity are not the same because of differences in their type and amount of fuel consumption.

In this paper, we assume that there will be a 1% annual increase in oil requirements for an additional kWh electricity generation of the existing and any new power plants due to the asset's degradation that starts after the first year of operation. Similarly, there will be a 1% annual

[28] For more information, see the summary literature and discussion regarding transportation costs of fuel imports into island economies are discussed in Weisser, D. (2004), "On the economics of electricity consumption in small island developing states: a role for renewable energy technologies?, Energy Policy, 32: 127–140

decrease in oil requirement for the new power plants until the time of operation due to technological advancement. Both parameters are assumed to be only a function of time. Furthermore, we assume that all candidate power plants are running with heavy fuel oil.

Table 1.1 Power Supply Mix by Plant and Fuel, Santiago Island as year of 2012

Generator	Year Built	Capacity (KW)	Type of Fuel	Fuel Consumption (liter/KWh)
Palmajero VI	2012	10,000	HFO	0.206
Palmajero V	2011	10,000	HFO	0.206
Palmajero III & IV	2008	14,800	HFO	0.213
Palmajero I & II	2002	10,800	HFO	0.220
Gamboa	1992	5,000	Diesel	0.206
Tarrafal	1995/2000	1,360	Diesel	0.228
Palmajero Gasoil	1987	2,400	Diesel	0.229
Calheta Miguel	2006	282	Diesel	0.246
Santa Caterina	2006	1,390	Diesel	0.251
Santa Cruz	n.d	640	Diesel	0.291

Sources: ELECTRA, World Bank (2011), UNIDO AND ECREEE (n.d.)

While deciding the capacity and the year of investment we consider both the growth in the demand for electricity and system reliability such that expensive diesel generators should be in an "idle" position as they serve as reserve capacity to maintain the grid reliability. The peak demand for electricity generation capacity is expected to grow as fast as the overall growth in energy demand. Therefore, the investments in new electric generation are expected to be in significant amounts as well as frequent.

1.3.3 Renewable Power Potential in Santiago

Because of its geographical conditions, Santiago Island of Cape Verde has great potential in both wind and solar electricity generation (Ranaboldo *et al.,* 2014). To illustrate, average annual wind speed at 70 m height is 9 m/s on the island (Cabral *et al.,* 2009) and the solar irradiation level is 6 kWh/m^2/day (Ranaboldo *et al.,* 2014; UNIDO and ECREEE, n.d.)[29]. Although levelised cost of electricity from solar PV is still higher than market prices for electricity and transmission investments are very high, off-grid solar systems might be the least-cost option for electricity supply in poor rural areas (Casillas and Kammen, 2010), especially in rural areas without grid access which have a big distance to the national grid (Deichmann *et al.,* 2011). Particularly off-grid solar PV and off-grid wind power applications are recommended for the isolated grids run by the electric utility (ELECTRA) where high MRC diesel plants operate, and grid connection is highly expensive due to the low population density in rural areas (World Bank, 2011; Ranaboldo *et al.,* 2014 . At the same time, the high solar irradiance level in the island allows residential, hotel and industrial users to utilize it for water heating that can potentially contribute to reducing fuel use for electricity generation and reduce overall peak demand on the grid.

The *Cabeólica* wind farm project is a public-private partnership (PPP) between the government of Cape Verde, the electric utility (ELECTRA) and a foreign private sector investor (InfraCO). The total number of onshore wind generators installed on the island is 11 with a generation capacity of 0.85 MW/each which translates into a total nominal capacity of 9.3 MW. This translates into 25% of the country's energy needs (InfraCO, n.d.)[30]. The wind farm is located in a southern part of Santiago Island, near the city of Praia. The wind power project is owned by a foreign owned IPP by the name of InfraCO. The foreign IPP is responsible for installation, operation, and

[29] See global atlas for renewable energy (e.g. global mean annual wind speed and mean annual solar irradiance levels), via (i) International Renewable Energy Agency at http://irena.masdar.ac.ae/ or (ii) UN supported wind and solar potential assessment map via http://en.openei.org/apps/SWERA/

[30] http://www.infracoafrica.com/projects-capeverde-cabeolicawind.asp

maintenance of the wind farm. The wind farm will occupy 30 hectares of land that will be rented at a fixed cost by the project from the local municipality. The wind farm is connected into the island's power grid by transmission lines which require additional transmission investments[31]. The project sells the electricity it produces to the national power grid and the public utility is the only purchaser of the wind power supplied by the private IPP. The public utility is responsible for the transmission as well as distribution of power to the existing users on the island.

The wind farm is assumed to operate from the beginning of 2011 to the end of 2030. The technical availability factor of the wind turbines is assumed for the purpose of this analysis to be 100%, with an average annual load (capacity) factor to be 40% for the wind farm. For the sake of simplicity, the availability factor and capacity factor of the wind turbines are assumed to be the same throughout the life of the project[32]. Furthermore, we assume that there are no negative externalities associated with wind power itself[33]. In our analysis, the power from wind is assumed to be supplied successfully such that the system is flexible enough to cope with wind power variability. The existing system is moreover assumed to be flexible enough to utilize the wind power when the wind blows. Hence, we assume that the wind power produced by the IPP is successfully utilized at all times and there is neither a penalty nor a compensation payment made by either party.

[31] We did not include transmission issues in this research.

[32] Availability factor directly relates to the technical point of view and describes the ability to <u>operate</u> wind farm safely. In recent years, technical availability of wind farms reaches to 99% so that wind farms can operate reliably about 8,672 hours of the year (24 hours * 365 days * 99%) out of 8,760 hours (24 hours * 365 days * 100%) (Kaldellis and Zafirakis, 2013). Therefore, 100% availability factor means that wind turbine is ready to generate electricity at all times of the year. But, wind turbine will actually generate electricity if wind blows above its cut-in (start running wind speed) and below its cut-out wind speed (shut-down wind speeds) that describes its capacity factor. Hence, different from availability factor of wind farm, capacity factor of wind turbines is a function of the wind speed in the area of construction of farm and the power curve of the particular wind turbines constructed. Therefore, capacity factor is the key parameter that actually <u>dictates</u> the amount of electricity that can be produced by the wind turbine. To illustrate, 10 MW of installed wind capacity generates annual energy equals 35,040 MWh with 100% (availability factor)* 8760 (total hours in a given year; 365 days* 24 hours) * 10 MW (total installed capacity) * 40% (average annual capacity factor) = 35,040 MWh.

[33] See footnote 11.

The capital costs of the project are assumed to be disbursed in two periods: 50% at the end of 2010 and the remaining payments at the end of 2011. The capital, and operating and maintenance (O&M) expenses of the wind project are presented in Table 1.2 above. Revenues of the foreign IPP are based here on an assumed PPA tariff that is agreed upon between the private supplier and public utility before the implementation of the project. We assume that IPP will continuously supply the electric power without any technical problems and subject to the pricing scheme of the PPA.

Table 1.2 Capital and O& M Costs of Installed Wind Capacity in Santiago in 2010[34]

Capital Costs*	**(€ - in millions)**
Equipment, procurement and construction (EPC)	15.2
Contingency	1.1
Land	0.35
Development	1.00
Total Capital Costs:	17.3
Fixed Operating Expenses+	
O&M (% of wind farm investment)	2.5%

Sources: (*): Clean Development Mechanism, UNFCCC, July 2006, p.14.
(+): estimates from Lundsager and Hansen (2002).

The main problem with renewables is that power produced by the wind generators may not be needed and cannot be consumed because there is no more thermal generation that can be shut off. This is not the fault of the IPP, so the utility will be obliged to pay the IPP under a take or pay contract even though it has no use for the electricity. The penalty or compensation payments

[34] For analysis, we converted all monetary variables from Euro to US $. Real exchange rate between Euro/$ is 0.78 in 2010. Real exchange rate appreciation/depreciation factor is assumed to be 0% throughout the project. The NPVs of the projects are presented in US $. From the reports, we assume that 1/3 of the total capital costs will spent on wind investments in Santiago Island as 9.5 MW out of 28 MW wind capacity will be invested in Santiago Island alone.

may also occur during the project operation time. The penalty payment is made by the private sector if it cannot supply the power, and the compensation payment is made by the public utility when the private IPP supplies more wind power than set in the contract. In the analysis that follows this PPA prices are assumed that illustrate how critical is the negotiation of the PPA price.

The total investment cost of the wind farm is €17.3 million in Santiago Island of Cape Verde. The financing will come from two sources: term debts from commercial banks and cash equity from the IPP. Total loan from term debt will be 60% of total investment cost (in nominal prices). This loan will be drawn as follows: €7.5 million in year 1 and €2.88 million in year 2. The real interest rate of the loan is 7% and the principal of the loan will be repaid in 8 equal consecutive annual instalments starting at the beginning of the year of power generation[35]. Interest accrued on the loan balance from the previous period is paid on a continuous basis, starting from year 2. The lender's benchmark is an annual debt service ratio of 1.7 minimum. The remaining investment costs of the proposed project will be covered by the IPP as cash equity and the required rate of return on the funds spent is 10%[36]. In the following analysis, three flat rate PPA prices are used: 100€ /MWh, 110 €/MWh, 120 €/MWh and 130 €/MWh that actually

[35] See Weiss and Sarro, 2013. They estimate impacts of long-term power purchase agreements on weighted average cost of capital changes so levelised cost of wind energy. They assume that banks will provide over 20 years loan duration that does not apply in reality in many countries give that longer duration of loan increases the risks associated with the loan itself. The interest rate of the loan itself also depends on duration of loan. In other words, banks do not charge the same interest rate for a 5 year loan duration and a 15 year loan duration. Therefore, their analysis is perhaps misleading and does not represent the situation in renewables.
[36] The pricing of renewable power subject to financing parameters and it is sensitive to financing arrangements of IPP investments, market and non-market (e.g. political risks) involved in its investments and highly affects the distribution of project benefits and costs. Also see similar cost-based approach for tariff setting in renewable projects in the USA, CREST Model, *Renewable Energy Cost Modeling: A Toolkit for Establishing Cost-Based Incentives in the United States*, National Renewable Energy Laboratory, US Department of Energy. The complete model and manual is available at: http://financere.nrel.gov/finance/content/CREST-model. For more theoretical discussion see Wolf Heinrich Reuter (2012), "Renewable energy investment: policy and market impacts", *Applied Energy,* 97: 249–254.

illustrate how financing costs (i.e. the weighted average cost of capital - WACC) are actually reflected in the price of wind electricity[37].

Because the private sector will generate a green source of electricity, it will also earn carbon credits from the Clean Development Mechanism (CDM)[38]. The $/MWh carbon credits are calculated by using a MWh to tCO_2 conversion since electricity production is calculated in MWh. The conversion factor for carbon is given as (tCO_2/MWh) 0.9049 and the carbon price/ton is assumed to be the rates offered by the Clean Development Mechanism (2006) which are 15 €/tonne until 2013 and 10 €/tonne after 2013[39]. Then by the amount of wind power replacement, annual earnings from carbon credits are calculated to be subject to a 7.5% excise tax.

1.4. Load Analysis and Methodology[40]

The load duration curve shows the relationship between the demand for capacity and time, i.e. the distribution of the demand for electricity over the time period (Poulin *et al.,* 2008)[41]. Unlike conventional generators, wind turbines generate electricity only when the wind blows at the wind farm site. This is why, in the load duration curve analysis, the wind power supply is best treated as a negative demand since its output is intermittent. To do this, we simply subtract the electricity produced by the wind generators in each hour to give net demands and form a new annual load

[37] Lower risk associated with the investments in renewables will lower the interest rate and higher will be the debt-equity ratio, so lower cost of equity-debt (WACC) will be – in turn lower levelized cost of energy.
[38] We assume these carbon payments will be paid throughout the project lifetime based on documents provided publicly available http://www.afdb.org/fileadmin/uploads/afdb/Documents/Environmental-and-Social-Assessments/ESIA%20-%20Cabeolica%20Wind%20Farm%20Projectt%20-%2018.03.2010%20EV.pdf
[39] See Clean Development Mechanism, UNFCCC, July 2006, p.27
[40]As an illustration, we use wind here however; it might be also solar power. The analysis is the same so that model can be applied for wind alone, and solar alone or wind and solar together.
[41]Time measure can be anything including daily, monthly or annual.

curve[42]. Over the year the amount of electricity generated is given by the period-by-period wind capacity factor multiplied by the total installed nominal wind capacity as shown in equation 1[43].

$$q_{wht} = \sum_w CF_{wht} \cdot K_{wt} \qquad \forall ht \qquad (1)$$

where:

h is time demand blocks in year (off-peak, mid-merit, peak)

t is planning years (t,…,T)

w is wind turbine

q_{wht} is total MW wind power generated from each wind turbine (w) at hours h of time t

CF_{wht} is capacity factor of wind turbine at hours h of time t (%)[44]

K_{wt} is wind turbine capacity MW at time t

The load duration curve (net of wind generation) depends on a number of wind turbines, the technical availability factor of the wind farm, and the quality and intensity of the wind at any moment. These factors in turn determine the capacity factor of the wind farm within the project site (i.e. wind farm site). Demand and supply has to balance every second, so the remaining demand for electricity (residual load) has to be supplied by the thermal generators. Wind power is therefore an exogenous variable in our analysis. This can be expressed as follows:

$$D^n_{ht} = D^g_{ht} - q_{wht} \qquad \forall ht \qquad (2)$$

where:

[42] See for example Lamont (2008) for similar approach.
[43] Lundsager and Hansen (2002) estimate the capacity factor at 30 meter height as 32% in Santiago Island. The speed of the wind is expected to be greater at 70 meters height, so we use 40% as being average wind power capacity factor in our empirical estimates. Also, see Cabral *et al.,* (2009) for wind speed comparison at different heights.
[44] Due to wind speed data constraints, we assume the capacity factor of wind farm is 40% at all times and at all demand blocks.

D_{ht}^{n} is demand net of wind capacity (equivalent of total supply of electricity from thermal generators) and D_{ht}^{g} is demand gross of wind capacity at block 'h' in MW.

From equation (2), we can clearly state that demand for electricity that conventional system is net of wind quantities such that:

$$\sum_z q_{zht} = D_{ht}^{n} \qquad \forall ht \qquad (3)$$

where:

q_{zht} is MW conventional electricity supplied by plant z "without" wind integration at hours h of time t

D_{ht}^{n} is total MW residual demand for electricity at hours "h" of time t

From equations (1) to (3), we can express the wind power output using the following equation:

$$\bar{q}_{wht} = \sum_z (q_{zht} - q'_{zht}) l_{ht} \qquad \forall ht \qquad (4)$$

where:

$\bar{q}_{wht}$ is wind electricity supplied at hours h of time t

q_{zht} is conventional electricity supplied by plant z "without" wind at hours h of time t

q'_{zht} is conventional electricity supplied by plant z "with" wind at hours h of time t

l is load (e.g. peak demand, off-peak demand load)

l_{ht} is hours of duration of load l (e.g. number of peak load hours, off-peak load hours) at time t

The economic dispatch method employs a mix of power generation plants with "the least cost -method" of electricity production. Generators are always ranked from the most economically efficient to the least economically efficient in such a way that the electric utility operates at minimum operating cost. This occurs when the plants are optimally dispatched in order from the lowest marginal running cost (MRC) \$/MWh to the highest marginal running cost \$/MWh.

Let us assume that there are three power supply technologies available: baseload plant, mid-merit plant and peaking plant to supply three load (i.e. demand); off-peak demand, mid-merit demand and peak demand. When the demand for electricity fluctuate between these loads when it is lowest (i.e. off-peak hours) and when it is highest (i.e. peak hours), the power supply technologies running in the system must also be altered in order to meet the fluctuations in demand. Baseload plants operate full time in order to meet the lowest demand for capacity. When the demand for electricity increases during the mid-merit and peak hours, additional capacity must be added to the baseload generation capacity and mid-merit capacity in order to meet the increased demand, respectively. Note that the peaking plants operate only a fraction of the time in order to meet the highest demand for capacity. Mid-merit power plants fill the gap between the peak load demand and baseload demand.

This is why, for the electricity system to be economically efficient, the baseload (peaking) plants are technologically more (less) capital intensive because of the high (low) levels utilization of the baseload (peaking) generation plants. This usually implies that the kWh marginal running cost, primarily fuel cost, of baseload plants (peak plants) is low (high). To sum up, baseload power plants are characterized by higher investment costs ($/kW) than peak power plants, but they produce electricity at lower marginal running cost ($/kWh) than the peak power plants. In order utility to supply at minimum cost (i.e. minimum price of energy), it is uneconomical to operate a baseload plant (peak plant) as a peak unit (baseload unit)[45]. In order utility to cover total cost of power supply, end-user price will exceed the marginal costs of baseload plants as price of energy must cover fuel and component for capital recovery running in the system[46].

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[45] For example, see Porat et al. (1997), Long-run marginal electricity generation costs in Israel, *Energy Policy*, 25(4):401-411.

[46]Even if both baseload and peak technologies are assumed to be the same with respect to their costs (i.e. identical capital costs per kW and identical marginal costs per kWh), baseload price would be equal to marginal cost of baseload plant and peak price would be equal to marginal cost of peak plant but all capital costs (sum of baseload and peak capacity costs) still need be recovered during the peak period via capital cost surcharge.Therefore, marginal

Graphically illustrated, the combined cycle turbine (CCT) generator in figure 1.1 is said to be the first dispatched generator while the single cycle gas turbine (SCT) generator is the second dispatched generator. Therefore, marginal running cost of combined cycle turbine (MRC_{CCT}) is less than marginal running cost of single cycle turbine (MRC_{SCT}) which is in turn less than the marginal running cost of diesel engine (MRC_{DIESEL}). The proper economic dispatch application for a power system results in both a better resource allocation and greater consumer benefits due to reduced power prices. Wind sources of power generation have the lowest MRC because they produce electricity without consuming fuel. Thus, wind electricity is always almost the first used when wind turbines are available for power generation since it is the lowest marginal running cost generator in the new mix.

Based on the figure above: (a) area of ACD represents the sum of the reduced electricity generation in MWh from each type of thermal power generation that is brought about by the introduction of the wind facility into the system and (b) the impacts of the wind generation on the optimal stacking of power plants such that the introducing of wind powered electricity generation tends to move the optional mix of plants towards an increase in the use of peak plants (cheap to build, expensive to operate)[47,48].

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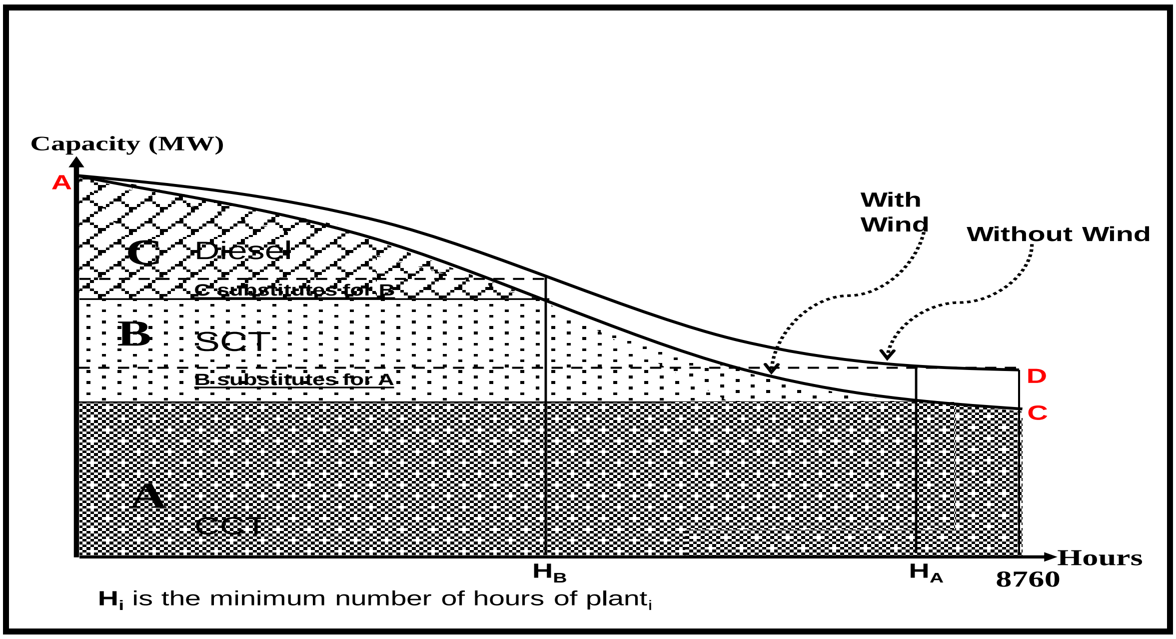
cost during peak hours would be still different than off-peak hours. The capital cost recovery charge would be estimated by the total capital costs of capacity running during the peak period over the period of peak hours. The difference will simply reflect the cost of adding capacity.

[47] See DeMiera *et al.,* (2008) and Fursch et al. (2012) for details of load analysis with wind integration. Both studies illustrate short-term impacts and changes in long-run equilibrium in generation mix with wind integration.

[48] Different from economic dispatch (ED) model I employ in this research, objective function includes more cost components and the constraint function includes more dynamic constraints such as start - up cost, transmission costs/constraints and unserved reserve cost, and thermal unit ramping constraints, required min on/off times of thermal plants etc. In this research, I did not take into account short-term dynamic operational constraints such as transmission constraints, required minimum load hours of conventional generators that help system planner for the purpose of system security, balancing the demand and supply, and maintaining the power quality. Examples of such analysis include Padh (2004), Delarue et al. (2009) and Tuohy *et al* (2009), and Staffell and Green (2015).

Figure 1.3 Annual Load Duration Curve "with" and "without" Wind Integration



The principal problem of the centralised electric utility systems is to minimize the generation costs subject to the set of system and regulatory constraints. The power system planners apply different optimization tools to solve the problems occurring at different time horizons. The total economic cost of expansion is composed of the sum of total fixed costs (investment and fixed operating and maintenance costs) for candidate thermal power plants, total variable costs (variable operating and maintenance costs, variable fuel operating costs) for both existing and chosen candidate plants in the future. Note that we do not choose optimal wind quantities here, but we minimize the total supply of power with a given wind capacity and demand growth for electricity for the next twenty years. Although there are numerous uncertainties in the operations as well as planning of power system such as wind speed and future demand load which need to be identified and taken care of are not accounted in this research.

$$O_{11} = PV_{TFC} = \sum_t^T \sum_c^C (1+r)^{-t} \left[I_c \frac{(1+i)^n}{(1+i)^n - 1} + F_{ct} \right] \cdot K_{ct} + \sum_t^T \sum_e^E (1+r)^{-t} \cdot F_{et} \cdot K_{et} \qquad (5)$$

where

PV_{TFC} is present value (discounted) of total fixed costs

t is planning years (t,…,T)

e is index of existing power plants

c is index of candidate power plants which are actually installed

i is interest rate (%)

r is discount rate (%)

n is economic life time of proposed candidate power plant (years)

I_c is capital cost of candidate power plant ($/MW)

K_{ct} and K_{et} are installed capacity of candidate plants and existing plants, respectively.

F_{ct} and F_{et} fixed operating and maintenance costs of candidate and existing power plant at time t ($/MW), respectively.

And, the present value (discounted) of total variable cost of energy supply is given by:

$$PV_{TVC} = \sum_t^T (1+r)^{-t} \left[\sum_h^H \sum_e^E \left(qf_{jet} \cdot Fpf_{jt} \right) \cdot q_{eht} \cdot l_{ht} + \sum_h^H \sum_c^C \left(qf_{jct} \cdot Fpf_{jt} \right) \cdot q_{cht} \cdot l_{ht} \right] \quad (6)$$

where

PV_{TVC} is present value (discounted) of total variable cost of energy supply

t **is** planning years (t,…,T)

h is time demand blocks in year (off-peak, mid-merit, peak)

l_{ht} is hours of duration of load l (e.g. number of peak hours, off-peak hours) at time t

qf_{jet} and qf_{jct} are the fuel consumption of candidate and existing power plants in year t (litre/MWh), respectively

Fpf_{jt} is price of j type fuel in year t ($/litre)

q_{eht} and q_{cht} are the electricity produced from each exisiting and installed candidate plant in interval h of year t (MW), respectively[49].

Therefore, optimal expansion is determined by minimizing discounted total costs; sum of discounted fixed and discounted variable costs. In equation (5), we simplify the analysis by assuming a single interest and discount rate in our simulations. For clarification purpose, we use the economic discount rate (r) for the minimization problem based on the sector being operated under a public electric utility. From equation (5), we further assume that fixed costs are uniformly distributed over the life-time of candidate plants and residual values of these power plants are equal to zero. In addition to this, we further assume that the economic value of decommissioned power plants equals zero such that decommissioning costs equals their residual values. Finally, we assume that there are no transmission constraints[50].

The variable costs affect the power generation mix and fixed and variable costs together affect the power expansion mix. Therefore, the total economic costs include both optimal stacking and optimal dispatching decisions within the model. Large amounts of electric power cannot be stored economically. Therefore, current and planned electricity generation has to meet demand for electricity at all times. The model presented in this chapter also uses the residual load with wind integration. The amount of electric power generation from conventional power plants is given by the availability factor (or technical availability) of each power plant.

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[49] Note that power quantities of thermal plants depends on availability factor (a_e, a_c) and installed power plant at time t (%) and capacity level of each power plant, in MW (K_{et}, K_{ct})

[50] Wind power curtailment due to transmission constraints exists even in countries where transmission infrastructure is in good shape, for example, this issue was recently raised in Kingdom Community wind farm in Vermont. For more information, see Cardwell, D. (2013) 'Potential of green energy is crimped by transmission shortcomings", International Herald Tribune, 16 August, p.16.

The negative load duration approach discussed above can be adapted in the case of Santiago Island. The treatment to the load demand curve with "wind" power will be the same throughout the project life time because the growth rate for electric demand is assumed to be the same for both the peak and the off-peak demand. The growth rates for electric demand are consistent with the demand study for the Island by ELECTRA[51]. The reliability issues associated with wind when the share of wind power is reduced over time are managed by adjusting the proportion of the diesel generators kept idle in order to be available to maintain the reliability and stability of the system.

We run simulations for the next twenty years because the useful life-time of wind power investments is typically 20 years. Note that each cost component is assumed to be constant regardless of the operating regime, with or without wind integration. It is possible to combine all discounted fixed and variable fuel and operating (i.e. total present values of costs, in €) and express it in a single function as follows:

$$min\ PV_{TFC} + PV_{TVC} \tag{7}$$

subject to

$$\textstyle\sum_e q_{eht} + \sum_c q_{cht} = D^n_{ht} \qquad \forall_{ht} \tag{8}$$

$$q_{eht} \leq a_e \cdot K_{et} \qquad \forall_{ht} \tag{9}$$

$$q_{cht} \leq a_c \cdot K_{ct} \qquad \forall_{ht} \tag{10}$$

$$q_{eht} \geq 0 \qquad \forall_{eht} \tag{11}$$

$$q_{cht} \geq 0 \qquad \forall_{cht} \tag{12}$$

$$K_{ct} \geq 0 \qquad \forall_{ct} \tag{13}$$

[51] See Market Study for Cape-Verde, *Simonsen Associados,* in February 2008 (in English).

where:

PV_{TFC} is present value (discounted) of total fixed costs

PV_{TVC} is present value (discounted) of total variable cost of energy supply

D_{ht}^{n} is demand net of wind capacity (equivalent of total supply of electricity from thermal generators)

q_{eht} and q_{cht} are the electricity produced from each existing (e) and installed candidate plants (c) in interval h of year t (MW), respectively.

a_{et} and a_{ct} are the availability factors of each existing and installed candidate plant in year t, respectively.

K_{ct} and K_{et} are installed capacity of existing and candidate plants installed in the future, respectively.

Non-negativity constraints identify the decision variables in our model. In order to compute the benefits and costs of this private sector wind investment, we will use quantities of thermal power "without" wind minus those "with" wind. Wind capacities are set as an exogenous variable. Hence, we do not determine optimum wind capacity, but we determine optimum thermal generation mix with wind integration. Any type of a new conventional generator added into the system is the most efficient generator which replaces the 'least economically efficient' generator in the existing power mix (Harberger, 1976). In contrast, adding generation from a wind farm does not replace the "least efficient" plant, but alters the power plant mixture that allows us to achieve the minimum cost combination again during the period. In our estimates, this process is repeated on an annual basis, and the generators are ranked according from the most efficient to the least efficient. We assume that the mix of thermal plants does not change between the "with" and "without" wind scenarios for Santiago Island. In other words, any changes in the per-unit level of capital and fuel costs due to changing the plant loads with wind integration are not accounted for.

Santiago's power system is small enough to allow us simply to rank the generators from the lowest to highest marginal running cost. If the installed amount of wind power penetrates the system, an analysis of the optimal power mix "with" wind must be carried out in order to derive the costs and benefits of wind power[52]. In our empirical estimates, we assume that non-fuel operating costs do not increase for the rest of the electric utility when the wind farm is integrated into the system: in reality they will increase. For instance, there may be a need for greater short term and long term reserve requirements once large amounts of wind are integrated into the existing generation[53]. As the wind capacity penetrates the system, these aspects of wind power might push system operators to take additional precautions in order to maintain the system's reliability[54] and adequacy[55] depending on the size of wind power penetration and system supply and demand characteristics (Holttinen and Hirvoven, 2005). This will ultimately increase the marginal cost per kWh of electricity production by the wind turbines, and it is not negligible (Smith *et al.,* 2004).

In addition, generators incur some start up and shut-down costs when utilities start operating or shutting down generators when the wind starts and stops blowing. The start-up and shut-down costs will vary depending on the plant type and as well as the flexibility of the generation mix. For example, baseload generators need some time to warm up before they can start generating electricity, so utilities may be prefer to keep them running even when wind generation is

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[52] See for example Lund, H., (2005).

[53] See for example Strbac *et al.,* (2007).

[54] Reliability is defined as "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements" (NERC, 2007).

[55] Adequacy is defined as " the ability of the electric system to supply the aggregate electrical demand and energy requirement of customers at all times, taking into account schedules and reasonably expected unscheduled outages of the system elements" (NERC, 2007).

(temporarily) available. Some proportion of the wind output produced during off-peak hours is likely to be surplus assuming that the baseload plants must operate at the same capacity throughout the project life[56]. This is the case for the future investments made on baseload plants, so this area is always in surplus power[57]. In our analysis, the wind power output in the area (figure 1.2) above the minimum level of thermal production is excluded in the measurement of the benefits of wind power from the perspective of the IPP, public utility and the economy.

1.5. An Integrated Analysis Mechanism

An integrated investment appraisal framework incorporates financial, economic and stakeholder impacts of the investment project[58]. In this framework, the actual benefits received and costs paid by each interest group due to the wind power project are calculated. This in turn allows us to re-allocate the benefits and costs according to the provision of the PPA. The integrated analysis framework also allows us to test the riskiness of all project variables that may affect the viability of the project so that a better management of the risks associated with the project can be made possible.

We empirically employ this framework in order to assess the costs and benefits of a new wind farm in Santiago Island, Cape Verde that was commissioned in September 2011[59]. The empirical results for Santiago Island illustrate how a set of estimates of the costs and benefits can be distributed between the public utility, the IPP, the economy and the local government. Due to

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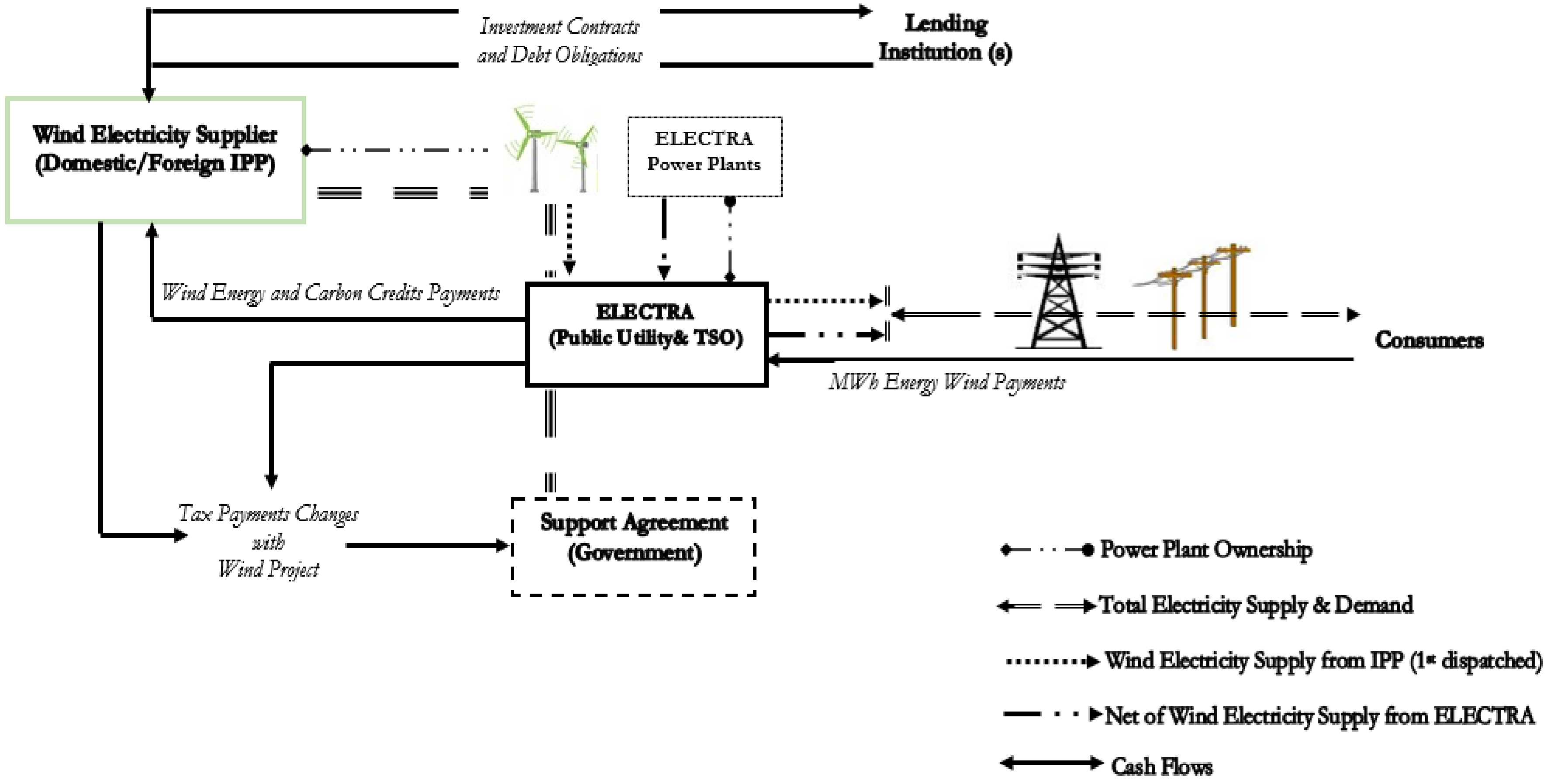
[56] Surplus of wind power can be manageable, see Lund, H., and Munster, E., (2003).

[57] The economic loss in this case is equivalent to wasted wind electric output when wind turbines produce an electric output but which is not utilized by the public utility.

[58] For details, see Jenkins, G.P., Kuo, C.Y., and Harberger, A.C. (2014) "Chapter 1: The Integrated Analysis", and also "Chapter 2: A Strategy for the Appraisal of Investment Projects", Cost - Benefit Analysis for Investment Decisions.

[59] We initially apply an economic dispatch model to find the least cost combination of power generators on an annual basis for the island. Wind power is examined in a way that it is used as supplementary or substitute for generation from conventional thermal power plants in Santiago Island, Republic of Cape Verde (hereafter Cape Verde). The wind turbines are introduced into a conventional power grid with multiple sources of thermal generation capacity such as fuel oil and diesel oil generators. Thus, the annual kWh of energy displaced by the wind turbines is estimated based on economic dispatch results.

Figure 1.4 PPA Greenfiel Contract Mechanism – take or pay contract



Source: own illustration.

the quality and strength of the wind speed and high delivered costs of petroleum products to the island, this location is potentially very favourable for this type of electricity generation project (Lundsager and Hansen, 2002; Cabral *et al.,* 2009; InfraCO, n.d.). The wind project in Cape Verde is of a commercial-scale, developed by an international investor/developer under a public-private partnership scheme (InfraCo, n.d.). The financial analysis produces results for both the private wind power supplier and the public utility.

1.5.1. The Independent Power Producer's Point of View

Different from the thermal electricity generation investments, the private investors who own such a wind farm incur almost zero variable cost (wind is free) to generate electricity, but face very substantial capital costs (Krohn *et al.,* 2009). Since the capital costs are known, the objective of a long-term power purchase contract (PPAs) is reducing the risks of the operation and providing a stable stream of revenues to the IPPs to cover their operating and maintenance costs and financing costs (Wiser and Pickle, 1998; Burer and Wustenhagen, 2009)[60]. In this way, their project can be made bankable and enable financial institutions to provide cheaper loans (lower interest rates together with longer duration of loan repayment period) for their investments as well as attract equity investors (Weiss and Sarro, 2013; Lesser and Su, 2008). This contractual arrangement will then lead to lower renewable energy prices that the private sector charges and the utility pays.

Both the MWh of the electricity supplied from wind turbines and selling price per MWh of power are pre-determined in the power contract. The price of energy per MWh is adjusted with

[60] Given that $i = r + R + (1 + r + R)gP^e$, i is nominal interest rate (i.e. rate of interest for borrowing), r is real interest rate and R is risk factor involved for a particular project depending on the type of investment and where it is actually implemented and so includes political risk, corruption in that country etc. and gP^e is the expected inflation over the life time of project. Hence, lower risk in investments translates into lower interest rates (lower financing cost) as well as a longer repayment period. Alternatively, higher risk will increase expectations on return so that investors can compensate and demand higher interest rates. Therefore, the loan-equity balance in private sector investments plays a crucial role in the price of energy they sell to the public sector and risk-sharing (i.e. role of PPA) between private and public sector is inevitable.

inflation to reflect the variations in the costs. Because we do not know the contract details signed between entities, we assume that price of wind energy does not change over time. Therefore, the revenues of the IPP are secured and the market risk of wind turbine investors from their operations are removed with the exception of the risk associated with their operating and maintenance costs (Jensen *et al.,* 2002; Baylis and Hall, 2000; Lock, 1995). The financial viability of the wind power project for the IPP is estimated by deducting the costs of capital, operating and maintenance (outflows) from the revenues from wind power sold out (inflows) to public utility. An additional source of revenues to the IPP is the (net of excise tax) revenue from the sale of the carbon credits that it receives for implementing this wind power project.The financial cash inflows, outflows, and net present value from the perspective of the IPP can be expressed as in equations 14, 15 and 16 below, respectively.

$$FB_t^{IPP} = \sum_h^H \bar{q}_{wht} \cdot p_{wt} + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \tag{14}$$

$$FC_t^{IPP} = I_t \cdot K_{wt} + F_{wt} \cdot K_{wt} + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \cdot \tau_c + \sum_h^H (\bar{q}_{wht} \cdot p_{wt} - F_{wt} \cdot K_{wt}) \cdot \tau_\pi$$

(15)

$$NPV_{t=0}^{IPP} = \sum_{t=0}^{T=20} (1+r)^{-t} (FB_t^{IPP} - FC_t^{IPP}) \tag{16}$$

where:

FB_t^{IPP}	is financial revenues accrued by private IPP from wind investments in period "t" (million \$)[61]
t	is planning years (t,…,T)
h	is time demand blocks in year (off-peak, mid-merit, peak)

[61] These benefits are secured as they are clearly specified in the PPA. This is fixed price PPA for wind quantities.

$\bar{q}_{wht}$	is MWh of wind energy produced from installed wind capacity at each load hours of time t
p_{wt}	is fixed contract price of wind power in \$/MWh[62]
q_{zht}	is MWh of energy produced from installed thermal power plant "without" wind integration at each load hours of time t
q'_{zht}	is MWh of energy produced from installed thermal power plant "with" wind integration at each load hours of time t
l_{ht}	is hours of duration of load l (e.g. number of peak hours, off-peak hours) at time t
ρ	is MWh to tCO_2 conversion for carbon credits
p_{ct}	is carbon credits earned from fuel replacement in \$/MWh
FC_t^{IPP}	is total cost of wind investments and operations paid by the IPP at time "t"
I_t	is investment costs associated with wind investments in million \$/MW
K_{wt}	is total wind capacity installed in MW
F_{wt}	is fixed operating and maintenance expenses of private IPP per MW of wind capacity in million \$/MW
π_c	is rate of excise tax on carbon credits paid by the IPP
τ_π	is rate of income tax paid by the IPP
r	is financial discount rate[63]

[62] Levelized cost of electricity from renewable is the minimum price that renewable supplier must get in order to just break-even. In Europe, this price (e.g. FIT) is higher than the LCOE per MWh as aim is to increase the share of renewable and promote more renewable installations. When debt obligations from the bank is taken into consideration (i.e. annual debt service coverage ratio), the price is higher than LCOE per MWh. Note that debt obligation starts with the operations, and usually last 8 years. Therefore, return on equity investment might be substantially higher than average years when debt is repaid. Thus, private sector has incentive to cheat by presenting shorter life for their investment to earn high return from high prices for the electricity they supply.

[63] The choice of private discount rate, however, reflects the perceived risk of the project, the regulatory and investment climate in a country where investment is actually undertaken, financing mechanism of the project and the profitability of alternative investments. The weighted average cost of capital (abstracting from the corporate tax rate component) is given by: $WACC = r_p * \omega_e + i_f * \omega_d$ where r_p and i_f are cost of equity and cost of debt, respectively. ω_e and ω_d are the share of equity and debt financing, respectively. Both the cost of equity and cost of debt is higher for wind investments undertaken in a developing country, for example UNDP suggest that cost of equity reach at 18% and cost of debt reach at 10% in developing countries (UNDP, 2013, p.34). We expect both the cost of equity and cost of debt to be smaller, however, if private sector sign long-term power purchase agreement

$NPV_{t=0}^{IPP}$ is net present value in millions of $ at 2010 price level

1.5.2. The State-Owned Utility Company's Point of View

From the public utility's perspective, the actual incremental benefits of having an IPP investing in wind turbines is the lower fuel consumption that results from sum of the reduced power generation from the conventional thermal generation plants[64]. These thermal generators are heterogeneous in terms of their characteristics such as age, type and amount of fuel used and the load factor. Fuel savings from individual thermal plants are therefore directly dependant on the kWh amount of electric power actually displaced from each conventional thermal generator by the power supplied by the wind energy.

The amount of payments to the IPP is made on the basis of the MWh of power supplied by the wind farm in a given year[65]. It is calculated without considering the type and time of displacement of power from conventional generators. In short, the net annual savings of the electric utility are estimated by the financial value of fuel savings (inflows) reduced by financial payments made to the wind power generation (outflows). In PPP-type renewable investments, all investment costs associated with the wind farm will be paid for by the foreign IPP, but the public utility pays for the additional investments needed in new transmission lines to connect the wind farm into the national grid and the reliability costs due to the intermittent and non-dispatchable nature of wind power as part of operating cost of the wind farm. Therefore, integration of wind turbines into the national grid involves capital and reliability costs – costs to mitigate the risks and maintain the grid reliability with wind integration. In this regard, the benefits of the renewables are savings in

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(Weiss and Sarro, 2013). Cabolica wind farm project is 70% debt financed and remaining 30% is equity financed (Mukasa *et al.,* 2013, p. 15). Therefore, the estimated WACC (the financial discount rate) is 12%. Because, long-term power purchase contracts reduces the risk of loan (Weiss and Sarro, 2013), we evaluated the private returns at 10% discount rate.

[64] See footnote 11.

[65] Note that we simplify our analysis in a way that we conduct our estimates on annual basis rather than daily or monthly.

fuel and emission savings, net of reliability and additional infrastructure costs with wind integration, and financial payments made to the IPP.

The financial cash inflow, outflows and the net present value from the perspective of the state owned utility company can be expressed as in equations 17, 18 and 19 below.

$$FB_t^{utility} = \sum_h^H \sum_z^Z \left(\frac{(q_{zht} - q'_{zht}) \cdot l_{ht}}{qf_{zjt}} \right) \cdot Fpf_{jt} + F_{zt} \cdot (K_{zt} - K'_{zt}) \qquad (17)$$

$$FC_t^{utility} = \sum_h^H \bar{q}_{wht} \cdot p_{wt} + \sum_h^H \bar{q}_{wht} \cdot Fpr_{wt} \qquad (18)$$

$$NPV_{t=0}^{utility} = \sum_{t=0}^{T=20} (1+r)^{-t} \left(FB_t^{utility} - FC_t^{utility} \right) \qquad (19)$$

where:

t	is planning years (t,…,T)
$FB_t^{utility}$	is financial benefits from fuel savings accrued by the public utility from wind investments in period t[66]
h	is time demand blocks in year (off-peak, mid-merit, peak)
l_{ht}	is hours of duration of load l (e.g. number of peak hours, off-peak hours) at time t
z	set of all existing thermal generators in the system in year t

[66] Financial price of fuel includes transportation charges and taxes, so financial cost of fuel for electricity generation is higher than world price of fuel. But, financial cost of fuel for electricity generation increases as world price increases by the amount of transport charges (% of world fuel prices) and tax distortions (% of CIF prices). Therefore, fuel cost of electricity generation ($/barrel) = World Price of Fuel (FOB) plus transportation charges and taxes paid.

q_{zht} is MWh of energy produced from installed thermal power plant “without” wind integration at each load hours of time t

q'_{zht} is MWh of energy produced from installed thermal power plant “with” wind integration at each load hours of time t

qf_{zjt} is quantities of fuel used by the i thermal generator in litres/MWh in period t

Fpf_{jt} is financial cost of j type of fuel in period t in $/litre

F_{zt} is fixed operating and maintenance costs of exisiting and candidate and existing thermal generators installed in the sytem, in $/MW

K_{zt} is MW of thermal capacity from each plant “without” wind integration at time t

K'_{zt} is MW of thermal capacity from each plant “with” wind integration at time t

$FC_t^{utility}$ is PPA payments paid by the public utility to the IPP and reliability costs paid in period t

$\bar{q}_{wht}$ is MWh of wind energy produced from installed wind capacity at each load hours of time t

p_{wt} is fixed contract price of wind power in $/MWh[67]

Fpr_w is financial cost of maintaining the reliable electricity supply in € per MWh of wind power supplied

r is utility discount rate [68]

$NPV_{t=0}^{utility}$ is net present value in millions of $ at 2010 price level

[67] Levelized cost of electricity from renewable is the minimum price that renewable supplier must get in order to just break-even. In Europe, this price (e.g. FIT) is higher than the LCOE per MWh as aim is to increase the share of renewable and promote more renewable installations. When debt obligations from the bank is taken into consideration (i.e. annual debt service coverage ratio), the price is higher than LCOE per MWh. Note that debt obligation starts with the operations, and usually last 8 years. Therefore, return on equity investment might be substantially higher than average years when debt is repaid. Thus, private sector has incentive to cheat by presenting shorter life for their investment to earn high return from high prices for the electricity they supply.

[68] For the utility and economy discount rate, using the Ramsey formula: $r = \rho + \theta g$ where ‘r’ is social discount rate, ‘ρ’ is the rate of pure time preference (measures impatience) that ranges between 1-3%, plus productivity of capital (return on investment) that is product of the consumption elasticity of marginal utility ‘θ’ (measures how fast marginal consumption decreases in consumption that ranges typically between 1-2%) and the growth rate ‘g’ (measures how fast consumption increases). Since, we do not know these variables, we use the discount rate that is used by the AfDB, that is 10%. See African Development Bank, Cape-Verde Report, page 6, available at: http://www.afdb.org/fileadmin/uploads/afdb/Documents/Project-and-Operations/Cape_Verde_-_Praia_Airport_Expansion_and_Modernisation_Project__PEMAP__-_Appraisal_Report.pdf

1.5.3. The Country- Economy's Point of View

The economic costs and benefits resulting from wind turbine investments are different from the financial benefits and costs due to tax distortions in the markets. The financial benefits and costs of the project to the Cape Verdean economy are adjusted for taxes and distortions to arrive at their real economic worth to the country as we carry out quantitative economic analysis from economic prices, not market prices. In order to move from financial analysis to economic analysis, we apply economic conversion factors to the financial prices and a foreign exchange premium to the inflows and outflows of foreign exchange caused by this project.

The economic benefits received from the wind project that accrue to the country are basically fuel savings and the taxes levied on the revenues of the IPP receive from the carbon credits. When moving from the financial analysis of fuel savings to the economic analysis of fuel savings, a fuel oil specific conversion factor is used to estimate the savings in fuel from a country-economy point of view[69]. In addition, any excise taxes levied on the value of the carbon credits are added to the economic benefits generated from the wind project in Santiago Island as they are a net inflow of resources to the country. On the economic costs side, the financial payments as stipulated by the PPA for each of the MWh of electricity supplied by the foreign IPP are made in foreign currencies. So these payments must be increased by the foreign exchange premium (FEP) to estimate the economic costs paid to the host country[70].

The economic resource inflows, outflows and net present value can be expressed as in equations 20, 21 and 22 below.

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[69] The import duties and VAT on fuel oil will cause the financial price to be greater than its economic cost while the existence of a foreign exchange premium will increase its economic cost. The net effect is to cause the economic value to be less than the financial price of fuel oil.

[70] FEP captures all domestic and international taxes and distortions associated with tradable items, so it captures the changes in the welfare in a country from foreign exchange payments that is paid to the private investor.

$$EB_t^{country} = \sum_h^H \sum_z^Z \left(\frac{(q_{zht} - q'_{zht}) \cdot l_{ht}}{qf_{jzt}} \right) \cdot Epf_{jt} + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \cdot \tau_c + F_{zt} \cdot (K_{zt} - K'_{zt}) + \sum_h^H (q_{wht} \cdot p_{wt} - F_{wt} \cdot K_{wt}) \cdot \tau_\pi$$

(20)

$$EC_t^{counry} = \sum_h^H (q_{wht} \cdot p_{wt}) \cdot (1 + FEP) + \sum_h^H q_{wht} \cdot Epr_w \tag{21}$$

$$NPV_{t=0}^{country} = \sum_{t=1}^{T=20} (1 + EOCK)^{-t} \left(EB_t^{country} - EC_t^{country} \right) \tag{22}$$

where:

$EB_t^{country}$ is economic benefits accrued by the country-economy from wind investments at time t

q_{zht} is MWh of energy produced from installed thermal power plant "without" wind integration at each load hours of time t

q'_{zht} is MWh of energy produced from installed thermal power plant "with" wind integration at each load hours of time t

qf_{zjt} is quantities of fuel used by the i thermal generator in litres/MWh in period t

Epf_{jt} is economic cost of fuel j type of fuel in time t in \$/litres adjusted by the corresponding conversion factor for fuel.

ρ is MWh to tCO_2 conversion for carbon credits

p_{ct} is carbon credits earned from fuel replacement in \$/MWh

F_{zt} is fixed operating and maintenance costs of exisiting and candidate and existing thermal generators installed in the sytem, in \$/MW

K_{zt} is MW of thermal capacity from each plant "without" wind integration at time t

K'_{zt} is MW of thermal capacity from each plant "with" wind integration at time t

π_c rate of excise tax on carbon credits paid by the IPP

τ_π rate of income tax paid by the IPP

Fpr_w is economic cost of maintaining the reliable electricity supply in \$ per MWh of wind power supplied

$EC_t^{country}$ is economic costs paid by the country-economy from wind investments at time t

FEP is foreign exchange premium paid on international currency transactions in %

$EOCK$ is economic opportunity cost of capital (discount rate)[71]

$NPV_{t=0}^{country}$ is net economic present value in millions of \$ at 2010 price level

1.5.4. Externality Analysis

Using an integrated approach, the stakeholder impact analysis is now computed. There are some externalities associated with the economic activity (project) that cause the economic benefits and costs to be different from the financial benefits and costs[72]. The difference between the economic resource flow and financial cash flow represent the tax and other externalities associated with the wind project in question. In this research, we identify and capture tax externalities created by the wind farm project. The stakeholder analysis of a typical renewable project is conducted to identify which particular segments of society reap the project benefits and which ones, if any, lose from the implementation of that particular renewable project. The stakeholder analysis of any project builds on the following relationship:

$$EV = FV + \sum Ext_k \tag{23}$$

where:

EV is the economic value of an input or output

[71] See footnote 68.

[72] See footnote 11. Although there are other externalities, non-monetized benefits and costs from this particular wind investment is excluded.

FV is the financial value of the same variable

$\sum Ext_k$ is the sum of all the externalities that make the economic value different from the financial value of the item.

In other words, the economic value of an item can be expressed as the sum of its financial value plus the value of externalities (i.e. taxes, tariffs, consumer/producer surplus). On the basis of identity above, the following relationship also holds, if a common economic discount rate is applied:

$$NPV_e^{EOCK} = NPV_f^{EOCK} + PV^{EOCK} \sum Ext_x \qquad (24)$$

where:

$\mathrm{NPV}_e^{\mathrm{EOCK}}$ is the PV of the net economic benefits (country) by the economic cost of capital

$\mathrm{NPV}_f^{\mathrm{EOCK}}$ is the PV of the net financial cash flow (utility) discounted by the economic cost of capital

$PV^{EOCK} \sum Ext_x$ is the sum of the PV of all the tax externalities generated by the wind project.

The Government of Cape Verde

In this case, government fiscal impacts arise because of the reduced tax revenues due to the decline in petroleum imports. On the other hand, the government collects taxes on the project's earnings from the sale of carbon credits. In addition, because both the fuel saving and the PPA payments to the IPP involve foreign exchange, a foreign exchange premium is applied to these offsetting resource flows. In this case the foreign exchange premium is simply the extra tax revenues that can be generated from the purchase of tradable goods and services when additional foreign exchange is acquired by Cape Verde. When foreign exchange is used by the project to make payments abroad, then the premium reflects the indirect taxes given up by the country.

There will be a loss in indirect tax revenue as fewer tradable goods and services can be now purchased by others.

$$\sum PV^{externalities} = NPV^{country} - NPV^{utility} \quad (25)$$

In brief, the government's fiscal impacts are equal to the sum of the loss in tax revenues from reduced oil imports (-), the gain in the value of the foreign exchange premium on fuel savings (+) and the loss in foreign exchange premium due to the payments now made to the IPP (-), and the gain in excise taxes levied on the carbon credits received by the private operators of the project (+)[73].

1.6. Empirical Results

Incorporating the simulation results into the integrated approach we described in section 1.5, the net impacts of renewable power integration into the island grid are presented for each point of view in order to show the viability of the wind project for each stakeholder. The benefits to the public utility are measured by the amount of fuel savings from conventional generators. The amount of fuel savings is estimated by the amount of power displaced by the wind turbines.

The costs of the wind project to the utility are the payments to the IPP in exchange for wind power. Therefore, the receipts of the IPP are the annual expenses of the public utility. The benefits of the project owner - the IPP - are measured by the amount of payments made by the public utility where the PPA price for its power is set in advance. The wind project costs to the IPP include both capital and operations and maintenance (O&M) expenses, which are deducted from the benefits. Finally, we apply a single rate of discount throughout the project life and the

[73] Note that this statement is true only if economic opportunity cost of capital (EOCK) is used to the count net cash flow for financial and economic analysis. The economic NPV and financial NPV will also differ due to application of economic conversion factors and the FEP and NTP adjustments made on the financial benefits and costs. This is how we get the government fiscal impacts as part of the externalities. Although we use the same rate discount rate for both financial and economic analysis, the EOCK may differ from the financial discount rate.

relevant discount rate for all interest groups is assumed to be the same at a rate of 10% (net of inflation)[74]. For economic analysis, the foreign exchange premium for Cape Verde is estimated as 10% (Kuo *et al.,* 2014) and the conversion factor for oil is calculated as 0.99. Incorporating the demand for and supply of electricity and wind parameters (both financial and economic), NPVs are estimated to show the beneficiaries and losers from the wind power project. The numerical results in Table 1.3 are estimated for world prices of HFO 180 and 380 at 70$/barrel and 60$/barrel, respectively[75]. Importing HFO 380 is cheaper for Cape-Verde than importing HFO 180 (World Bank, 2011). Note that international and domestic transportation charges as well as taxes (both import tariff and excise tax) will be added in order to arrive at the financial cost of fuel for electricity generation in Cape-Verde.

Local government is planning a shift from HFO180 to HFO380 starting from 2015 (World Bank, 2011). That is why we test the impacts of changes in HFO380 on the public utility and economy of Cape-Verde. Note that there is no relationship between oil prices and the net present value of the IPP. Oil prices affect the cash flow statement of public utility, the country-economy of Cape Verde and the government. Although the foreign IPP may obtain capital more cheaply, we assume that the economic cost of capital for Cape Verde equals the cost of capital to the IPP, as reflected in the calculations below.

We present results from economic impact analysis and distributional assessments for particular groups of concern namely the IPP, electric utility, country-economy and national government. We present empirical results based on the fixed power purchase price (PPA) of 120 $/MWh and world heavy fuel oil prices HFO 180 and HFO 380 for electricity generation of 70$/barrel and

[74] Note that costs are paid in year 0 but all future benefits are discounted using the discount rate so results are sensitive to discount rates that vary from country to country and it is reflection of country specific and project specific variables including opportunity cost of capital, rate of inflation and risk and uncertainty associated in investments.

[75] The delivered price for per barrel at Santiago is equivalent US $112.50 /barrel due to the high transportation costs, taxes paid on fuel imports both to get the fuel to Cape Verde and transport it domestically to the generation plants.

60$/barrel as they are key parameters in such projects. We find that at a price of 120 $/MWh, the net present value of the gain to the foreign independent power supplier (IPP) is $6.6 million, net gain of the economy of Cape-Verde is $1.1 million, the net gain of the electric utility is $6.1 million and the net loss of government tax revenues is $3.8 million. We then test the impacts of the lower-bound price of wind energy at 100 $/MWh and upper-bound price of wind energy at 130 $/MWh while keeping HFO 180 and HFO 380 fuel prices constant at 70$/barrel and 60$/barrel, respectively.

Table 1.3 Financial and Economic Feasibility of Wind Power Investment with Different PPA Pricing of Wind Energy (NPV values in billion $ and evaluated at 10% discount rate)[76]

Perspective/ PPA Tariff ($/MWh)	IPP	Utility	Cape-Verde	Gov't Externality
94.4	0	11.7	8.3	-3.4
100	1.4	10.2	6.7	-3.5
110	4.0	7.5	3.9	-3.6
120	**6.5**	**4.8**	**1.0**	**-3.8**
123.7	7.5	3.8	0	-3.8
130	9.1	2.1	-1.8	-3.9
137.8	11.1	0	-4.0	-4.0
140	11.7	-0.6	-4.6	-4.0

Source: own estimates

We find that with lower prices for wind energy, the net gains of the foreign IPP decrease to $3.9 million, net gains of the economy of Cape-Verde increase to $3.9 million, net gains of the electric utility increase to $7.5 million and the net loss of government tax revenues decreases to $3.6 million[77]. In comparison to the status quo, we find that with upper-bound price of wind energy,

[76] See equations (24) and (25).

[77] Note that the ELECTRA's return on capital is negative and ELECTRA's operations are mostly financed with debt and these debts are financed by local government. Therefore, wind project can potentially decrease the heavy burden on government budgeting the ELECTRA's deficits and these government funds saved from wind project can be

the net gains of the foreign IPP increase to $7.5 million, net gains of the economy of Cape-Verde decrease to -$1.8 million, net gains of the electric utility decrease to $2.1 million and the net loss of government tax revenues increases to -$3.9 million. The reason for such high gains for the foreign wind power supplier is because the price of wind energy is higher than the actual levelised cost of energy (break-even price) for this particular wind investment and the higher price of wind energy comes from the financing structure and riskiness of these projects.

At the PPA price of $ 120 per MWh, we find that the private investor, public utility (consumers) and country-economy are expected to earn a substantial return from the project while the government of Cape Verde will lose with such an arrangement for the values considered in this table. In this case, Table 1.3 suggest that the break-even price of PPA prices that makes the public utility and country (Cape-Verde) indifferent between generation from the wind farm or by its generation plants would be approximately $123.7 per MWh and 137.8 per MWh, respectively – a price well above which makes the profits of private investor (IPP) equal to zero: $94.4 per MWh.

The analysis using an integrated investment appraisal framework also allow us to determine the values of the key variables such as price of wind energy, fuel price, the expected capacity factor for the wind generation, discount factor that would make electricity generation by wind turbines financially and economically feasible. In our analysis, we also test the impact of the price of oil/barrel (holding everything else constant) to show its impacts on interest groups, but especially on the public utility and the island economy. We test the impacts of various fuel costs (i.e. HFO 380) for electricity generation on results while keeping the price of wind energy at 120 $/MWh[78].

used elsewhere in the form of public investments. (e.g. better health and educations services, road improvements, health intervention programs etc).

[78] We test for HFO 380 because most of the benefits will come from reduction in HFO 380 as HFO 380 will be imported starting from 2015; 5 years after the project actually implemented.

In comparison to the status quo (where the. price of HFO380 equals 60$/barrel). We find that at a fuel price of 50$/barrel, net gains to the economy of Cape-Verde decrease to -$2.5 million, net gains of the electric utility decrease to $1 million but the net gains of the foreign IPP do not change as both quantities and prices are guaranteed before the implementation of wind investment and contract prices are wholly independent of fuel-oil price changes. The utility and country-economy benefits increase with higher fuel prices. Therefore, fuel price risk is entirely borne by the economy and the utility and such wind investments can only be viable with an expectation of an increase in fuel prices.

Table 1.4 Sensitivity Results from World Price of HFO 380/Barrel (NPV values in million $, evaluated at 10% discount rate and PPA Tariff at 120 $/MWh)

Perspective/ World Price of HFO 380 ($/Barrel)	IPP	Utility	Cape-Verde	Gov't Externality
	6.5	4.8	1.0	-3.8
45	6.5	-0.8	-4.3	-3.4
47	6.5	0	-3.5	-3.5
50	6.5	1.0	-2.5	-3.5
55	6.5	2.9	-0.7	-3.7
57	6.5	3.7	0	-3.7
60	**6.5**	**4.8**	**1.0**	**-3.8**
65	6.5	6.7	2.8	-3.9
70	6.5	8.6	4.6	-4.0
75	6.5	10.5	6.4	-4.1
80	6.5	12.3	8.1	-4.2

Source: own estimates

We can clearly conclude that holding everything else constant, if the world price of crude oil is expected to increase over time, the public utility and the country-economy will gain from the project, and vice versa. Since the payments to IPP are independent of the oil price, the NPV of the foreign IPP remains unchanged with respect to the change in the price of oil. In this case, the break-even price of heavy fuel oil that makes the utility indifferent between generation from the wind farm or by its generation plants would be approximately $47/barrel – a fuel price below current level at $65/barrel[79,80]. With the energy costs as stated, the wind turbine electricity generation is economically viable at relatively high domestic fuel prices caused by either high crude oil prices and/or high transportation costs. Santiago Island has some of the highest transportation costs for fuels of any jurisdiction in the world. High fuel transportation costs cause domestic fuel prices to be high and increases the attractiveness of electricity generation by wind.

Similar to other sensitivity analysis and holding all other variables constant, wind capacity factors which bring net present value below zero are unacceptable whilst wind capacity factors that produce net present value above zero are acceptable. With a given stated wind investment costs, price of wind energy and fuel prices, there is a positive relationship between the wind capacity factor of wind farm and the NPVs of the interest groups with the exception of government[81]. An increase in wind capacity factor increases the amount of wind energy produced and sold, so the amount payments to the IPP and the fuel savings from installed wind capacity are both increased. The tax losses of the government of Cape-Verde increases at the higher capacity factor which means the taxes paid by the IPP to government is less than taxes foregone from oil imports.

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[79] Although oil prices dropped sharply in mid-2014 down to below 50 $/barrel. The recent crude oil forecasts released by the US Energy Information Administration (April 2015) and World Bank (April 2015) show that average annual oil prices will increase over time. For complete EIA report, see http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf and for complete WB, see http://www.worldbank.org/content/dam/Worldbank/GEP/GEPcommodities/GEP2015b_commodity_Apr2015.pdf

[80] For real time oil price data, see for example: http://www.oil-price.net/. These prices are world prices, so exclude transportation and taxes paid by utilities, however.

[81] Note that the capacity factor determines annual energy production from wind as presented in equation 1, so it affects the levelised cost of energy (LCOE) from wind investment. For instance, lower (higher) capacity factor increases (decreases) the LCOE relative to the reference at 40%. This is because lower capacity factor of wind means lower energy generated from wind turbine installations given that capital costs per MW of wind is independent from production of energy from wind. For more details, see Tegen et al., (2012), 2010 Cost of Wind Energy Review, National Renewable Energy Laboratory and Kost *et al.,* (2013), Levelised Cost of Electricity: Renewable Energy Technologies Study, Fraunhofer Institute for Solar Energy Systems, Germany.

Within the range of wind capacity factors considered in this analysis, net change in private sector earnings is very sensitive to the capacity factor compared to net change in earnings by the utility and economy of Cape-Verde. This is because wind energy payments accrued over time cannot compensate the high capital costs paid by private sector that occur immediately upon implementation of the project. Therefore, private sector supplier takes more risk of lower capacity factor of wind farm while utility takes more risks of lower heavy fuel oil prices in the implementation of wind farm project.

Table 1.5 Sensitivity Results from Different Wind Capacity Factor (NPV values in million $, evaluated at 10% discount rate and PPA Tariff at 120 $/MWh)

Perspective/ Wind Capacity Factor (%)	IPP	Utility	Cape-Verde	Gov't Externality
30%	-1.9	3.6	0.7	-2.9
32%	-0.2	3.8	0.8	-3.1
34%	1.5	4.1	0.8	-3.2
36%	3.2	4.3	0.9	-3.4
38%	4.9	4.6	1.0	-3.6
40%	**6.5**	**4.8**	**1.0**	**-3.8**
42%	8.2	5.0	1.1	-3.9
44%	9.9	5.3	1.2	-4.1
46%	11.6	5.5	1.3	-4.3
48%	13.3	5.8	1.3	-4.5
50%	15.0	6.0	1.4	-4.6

Source: own estimates

Discount rate used in the calculations is 10%, but there is no single rate of return that is appropriate for every project and country. The choice of discount rate can potentially make a significant difference to whether the net present value of a project is positive especially when costs/benefits accrue over long periods. A high (low) discount rate implies that a much greater (smaller) weight is put on current costs and benefits relative to those that occur in the future.

Hence, we finally test the effect of different discount rates on the project outcomes for the interest groups.

Table 1.6 Sensitivity Results from Different Choice of Discount Rate (NPV values in million $, evaluated at 40% wind capacity factor and PPA Tariff at 120 $/MWh)

Perspective/ Discount Rate (%)	IPP	Utility	Cape-Verde	Gov't Externality
5%	18.5	6.7	1.6	-5.1
6%	15.5	6.2	1.5	-4.8
7%	12.9	5.8	1.3	-4.5
8%	10.5	5.4	1.2	-4.2
9%	8.4	5.1	1.1	-4.0
10%	**6.5**	**4.8**	**1.0**	**-3.8**
11%	4.9	4.5	1.0	-3.6
12%	3.4	4.3	0.9	-3.4
13%	2.1	4.1	0.8	-3.2
14%	0.9	3.9	0.8	-3.1
15%	-0.2	3.7	0.8	-3.0

Source: own estimates

As shown in Table 1.6, our estimates of private return on investment are fairly sensitive to the discount rate assumption. As we expect, higher discount rate reduces the present value of the benefits which are accrued over time, while having much smaller effect on the initial capital costs involved in the project. For instance, increasing the discount rate from 10 percent to 12 percent decreases private returns by the amount of 48%, equivalent to net reduction by the amount of 3.1 million $ from the baseline result of 6.5 million $. Decreasing the discount rate from 10 percent to 8 percent increases the private returns by about 62 %, equivalent to net increase by the amount of 4 million $, however. At the 15% discount rate, the private costs outweigh the discounted private benefits so private sector will not generate any return from the invested capital on this wind investment. At this high rate of discount rate, the electric utility and economy of Cape-

Verde will still save nearly a million $ over a 20-year period and 3.7 million $ over a 20-year period, respectively.

1.7. Concluding Remarks and Policy Recommendations

Today, the Government of Cape-Verde intends to pursue the objective of harnessing power from wind energy with the joint participation and collaboration of the private sector – so called public-private partnership (PPP). Assessing the cost reduction potential from renewables is not sufficient to conclude whether it is truly viable for the economy or not. The objective of this paper is to introduce a mechanism to evaluate the private sector renewable power investments such as wind and solar using an integrated analysis. Based on this integrated mechanism, the wind project will provide a substantial return for the foreign IPP. For the utility and the country the net benefits of the projects are directly tied to the world price of petroleum fuels, capacity factor of wind farm and the price of wind energy (PPA price of wind energy) supplied by the private sector. Therefore, policy initiatives to expand the use of grid connected utility scale wind integration in Cape-Verde seem to be promising, especially if the expectation is that the fuel prices will increase over time[82].

The wind electricity tariff has to be a socially desirable tariff that is to say it has to be at the lowest possible cost of supplying wind energy. On the flip side, the price of wind energy must also yield a sufficiently high rate of return to the IPP so that these investments will still be attractive from the private sector point of view and bankable from the lender's point of view. As of today, long-term contracts between the private sector entity and the government (on behalf of the electric utility) provide price certainty in renewable investments, allowing producers to increase debt leverage at lower interest rates. Based on the long-term contracts, wind energy is tied to its own levelised cost of energy and the electric utility obliged to buy wind electricity at a

[82] See footnote 79 and 80.

fixed price for 20 years. If the price of wind energy would vary with dispatching on both system costs and output, short-term improved operating efficiencies and long-term improved investments in generation could be reflected in the price of wind energy. Therefore, an effective regulatory oversight in the operations of the market by means of new tariff mechanisms considering the levelised costs of avoided energy and/or future long-term electricity investment needs of the country can potentially increase county-economy welfare gains from cheap(er) wind integration alongside with improved operating efficiencies. This will require integrating power market operations into power purchase contracts and essentially risk re-allocations between IPP and the government.

The major concern of private sector participation is tied to weak institutional and regulatory mechanisms (i.e. governance) in developing countries. Weak governance results in higher risks involved in any type of infrastructure investments and so increases the cost of both equity and debt financing of such projects – and hence the price of energy[83]. Unlike many developing countries, Cape-Verde has a relatively high governance index with respect to the quality of its institutions including the rule of law, control of corruption, property rights etc., so we can argue that such contractual arrangements must be highly credible from the perspectives of both the private sector and lenders.

Note that the distribution or say allocation of utility savings from wind investments depends on Cape-Verde's public policy (institutional environment). These savings can be passed on to existing consumers as a lower electricity price. Although it sounds economically viable option, it might not be the socially desirable option. These economic savings have alternative uses that potentially might yield higher economic return from the overall welfare point of view. In Cape-Verde, 28.1% of all households are poor (25% of total urban population and 51% of total rural

[83] Payments include both energy (MWh) and capacity (MW) if a private sector investment is thermal plant.

population)[84] - but subsidies in electricity consumption in Cape-Verde reached only to the bottom 20% of all poor, so allocation of electricity subsidies is said to be regressive in Cape-Verde (Angel-Urdinola and Wodon, 2008)[85]. Hence, if Cape-Verde passes these savings to existing consumers by means of lower energy prices, it will increase consumer surplus of existing connections while making this subsidy distribution even more regressive. Given that these islands are small in size, we expect it to have relatively higher potential for achieving rural electrification in a more cost effective way because rural residents live closer to existing networks in such small islands. The use of these economic savings to finance capital investments in new connections for the poor-urban population and/or to subsidize off-grid rural electrification might be economically and socially more desirable than passing these savings to existing connections. Careful impact analysis in terms of use and distribution of these savings will necessarily show us how much wind integration with private sector involvement might solve energy poverty in Cape-Verde.

1.8 Limitations of Research and Future Work

In this research, we neglect the following important issues although they potentially can alter the net financial and economic benefits. We assume that wind integration is successful so all wind energy produced is supplied from the wind farms to national grid end-users. But, if all wind output could not feed into the system successfully, these wind quantities should be reflected as wind output net of transmission losses and constraints and deducted from wind power sales. Secondly, we ignore the additional investment costs in the transmission and distribution systems, but connecting wind farms into the grid indeed requires such investments. The quantification and

[84] Authors define poor households based on 2000-2001 household survey as follows: household is poor if the household annual per capita consumption falls below the official poverty line in Cape-Verde (amount equivalent to Cape-Verdean Escudo CVE 43,249.8 per capita a year).

[85] See for example, Komives, K., Foster, Vivien, Halpren, J. and Wodon, Q (2005), "Water, Electricity and Poor: Who Benefits from Utilities Subsidies?", World Bank Publications, The World Bank. Wodon, Quentin, and collaborators. 2008. "Electricity Tariffs and the Poor: Case Studies for Sub-Saharan Africa." AICD, World Bank, Washington, DC.

monetization of wind energy losses and additional investments should be considered in order to better estimate net gain and loss for interest groups. Thirdly, we exclude start-up and minimum loads costs in defining the supply curve that can potentially increase the cost of integrating wind power into the system (e.g. Zhang et al., 2015). Finally, we did not include avoided health benefits and net change in employment from wind farm project as they are not easily quantifiable and monetized especially in less developed countries.

Based on the empirical findings and policy recommendations from this research, we believe the following research questions will help regulators to design and implement better energy policies for their economic and social development. The large volume of energy losses due to low infrastructure quality is a major concern in Santiago Island of Cape Verde. As of 2009, energy losses from electricity generation were 26.1% in ELECTRA's power operations in Cape Verde (Garmendia and Benitez, 2010). This means that only 74% of generated electricity is actually distributed to existing customers – that is equivalent to 137 GWh out of 185 GWh total electricity generation in 2009. Economic costs of energy losses are enormous in Cape Verde. For example, losses in firms' sales revenue from power outages are 8% in comparison to 0.8% in middle-income countries (Garmendia and Benitez, 2010). This means that there are considerable cost savings possible from improving the performance in the existing generation and transmission and distribution system. Therefore, every dollar spent on improving the existing infrastructure such as reducing energy losses from low quality infrastructure might yield higher economic and environmental benefits in the form of cost and emission savings than cost and emission reduction savings with a wind expansion project but poor grid infrastructure.

Appendices

List of Symbols

t	planning years (t,…,T)
h	time demand blocks in year
l_{ht}	duration of time interval h (number of hours in each time interval)
z	index of all power plants
$e(z)$	index of existing power plants
$w(e)$	index of existing wind power plants
$c(z)$	index of candidate power plants
q_{wht}	total MW wind power generated from each wind turbine at hours h of time t
CF_{wht}	capacity factor of wind turbine at hours h of time t (%)
K_{wt}	wind turbine capacity MW at time t
$\bar{q}_{wht}$	MWh of wind energy from installed wind capacity at each load hours of time t
D^{g}_{ht}	MW demand for electric power gross of wind energy in time interval h in year t
D^{n}_{ht}	MW demand for electric power net of wind energy in time interval h in year t
q_{zht}	conventional electricity supplied by plant z "without" wind at hours h of time t
q'_{zht}	conventional electricity supplied by plant z "with" wind at hours h of time t
qf_{jet}	fuel consumption of existing power plants in year t (litre/MWh)
qf_{jct}	fuel consumption of candidate power plants in year t (litre/MWh)
Fpf_{jt}	price of j type fuel in year t ($/litre)
Fpr_{w}	cost of maintaining the reliable electricity supply in $ per MWh of wind energy
K_{et}	installed power of existing power plants in year t in MW
K_{ct}	capacity additions in year t from thermal units (MW)
n	economic life time of candidate power plant (years)
I_{c}	capital cost of candidate power plant in year t ($/MW)
F_{ct}	fixed operating and maintenance costs of candidate power plant in year t ($/MW)
F_{et}	fixed operating and maintenance costs of candidate power plant in year t ($/MW)
a_{e}	availability factor of existing conventional plant at interval h of the year t (%)
a_{c}	availability factor of existing conventional plant at interval h of the year t (%)
PV_{TFC}	present value (discounted) of total fixed costs
PV_{TVC}	present value (discounted) of total variable cost of energy supply
ρ	MWh to tCO_2 conversion for carbon credits
p_{ct}	carbon credits earned from fuel replacement in $/MWh
π_{c}	rate of excise tax on carbon credits paid by the IPP

τ_π	rate of income tax paid by the IPP
FEP	foreign exchange premium paid on international currency transactions in %
$EOCK$	economic opportunity cost of capital (discount rate)
r	real discount rate (%)
i	interest rate (%)
NPV	net present values

Economic Parameters of Candidate Technologies[86]

c	$num_c - MW_c$	I_c	F_c	n	f_{ct}	a_c
Peak	4 - 5,10,15,20	550,000	12,000	25	0.240	95%
Off-Peak	4 - 5,10,15,20	750,000	35,000	25	0.185	95%

[86] Note that we assume that candidate off-peak plants consume 20% less than the existing thermal running with fuel oil plant whilst peaking plants consume 30% more than candidate off-peak thermal plant running with heavy fuel oil. Results are sensitive to these capital costs, fixed costs and fuel costs assumptions, however.

CHAPTER 2: ECONOMIC IMPLICATIONS OF RENEWABLE ENERGY POLICIES IN THE CYPRIOT ELECTRICITY MARKET

2.1 Introduction

Given that sustainable development is '*development which meets the needs of the present without compromising the ability of future generations to meet their own needs.' (WCED, 1987);* reliable, affordable as well as environmentally friendly supplies of electricity are vital elements to sustain the country's goal of *well – being* (Dincer, 2000, Kaygusuz and Kaygusuz, 2002; Kaygusuz, 2007; Guneri, 2008). Therefore, sustainability clearly characterizes the desired but delicate balance between sustaining the current and future economic growth while preserving the quality of environment. Reliance on a supply of electricity from exhaustible natural resources clearly threatens the well-being of current and future societies due to their limited availability, fluctuating world prices and their adverse effect on environment from pollutant emissions. Therefore, investments on renewable energy sources (RES) offer a solution to the triple problem of energy resource and carbon constraints while enhancing the security of energy supply. Renewable energy sources in the form of wind power, solar power, bioenergy, ocean energy, geothermal energy, hydro energy, are indigenously available in most parts of the world and generate electricity at relatively low variable cost with almost no emissions. Total energy supply of countries, however, will still come from depletable fuel sources such as fuel oil, coal, natural gas (Global Energy Statistical Yearbook, 2013)[87].

[87] For detailed fuel-type data, see http://yearbook.enerdata.net/

Renewable power sources tend to reduce external energy dependency of non-oil producing countries on the level of importation, helping diversity of energy supply mix in order to mitigate the risk of price and quantity associated with the fossil fuels, and potentially reduce the risk of climate change (Domac *et al.*, 2005)[88]. These are the main motivations listed for a long-term political desire in both industrialized and developing economies to shift away from the conventional thermal supply and to seek ways of supplying electricity in alternative ways (Murray, 2009; Gelabert *et al.*, 2011)[89]. In addition, these factors have fostered ambitious targets and/or implementation of a wide range of policies to promote the use of renewable energy sources (IPCC 2011; Teckenburg *et al.*, 2011; Mikucki and Sleszynski, 2008; Murray, 2009; Reiche and Bechberger, 2004)[90].

Electricity expansion planning is a long run problem that is closely related to both the *scaling* and *timing* problem of new investments in an electricity generation plant to meet the increase in demand for electric power at its lowest cost, whilst system reliability is maintained (Turvey, 1963; Davitian, 1978; Covarrbias, 1979; Bloom, 1982; IAEA, 1984; Kothari and Kroese, 2009). The need for investment in new power plant(s) occurs when the existing capacity cannot supply the growing demand for electric power during peak hours simply by increasing their operational hours or can only increase by putting risk on the reliability of the system.

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[88] International Energy Outlook (2010) projections on both supply of and demand for the energy which for the period of 2007 to 2035 reveals that accumulation of CO_2 emissions will be continued as energy generation from dirty fuel sources such as heavy fuel oil and coal will be still dominant in the world power supply between the period of 2007-2035. See full report available at <www.eia.doe.gov/oiaf/ieo/pdf/0484(2010).pdf>

[89] Nuclear power is cheap and clean source of power generation, but the construction of nuclear power stations is unlikely to increase (Lior, 2010) and public opinion against nuclear stations increase further especially after the Fukushima Daiichi nuclear disaster inn Japan.

[90] Frondel *et al.,* (2010) strictly argue that government incentives to renewables do not encourage competition among producers and blocks the innovation process so increases the dependency on the existing technologies. They further argue that spending on R&D to improve efficiency might be a cost-effective measure in early stages of renewable integration than that of heavy subsidy programs given to renewable sources. On the contrary, Van Rooijen and Wees (2006) argue that uncertainty as well as discontinuity of national energy policies in Netherland is the main for small development in renewable energy sector.

In the past, the basic objective was simply to minimize the total sum of discounted total costs (fixed and variable costs) of the electric supply over the long-term horizon while satisfying a set of constraints[91]. The dimension of the electricity generation and expansion constraints in the modern optimization models are multiple due to increasing emissions from conventional electricity generation and increase in the use of renewable sources in electricity generation (Jia *et al.*, 2000; Afgan and Carvalho, 2001; Fichtner, 2010). The potential greenhouse gas mitigation measures are multiple and include carbon capture storage and sequestration, energy efficiency and conservation programs and fuel switching. Among these mitigation measures, fuel switching by means of increasing the share of renewable energy sources has come to dominate the electricity markets as investing in renewables is believed to be the most efficient and effective solutions to environmental problems. This in turn has resulted in enforcement of green regulations and financial incentives that govern the market access to renewable energy sources[92].

The electricity demand of Cyprus has been increasing rapidly, for example, the electricity consumption in Cyprus has doubled between 1990 and 2003 and the expectation is that electricity demand of Cyprus will triple in the coming 20-25 years (Zachariadis, 2010). The electricity generation in Cyprus relies almost on fuel oil inputs. Therefore, increase in demand for electricity will potentially (i) increase the fuel oil imports of the electric utility (Electricity Authority of Cyprus, EAC), (ii) make Cyprus more vulnerable to potential macroeconomic imbalances through increase in its energy trade deficit, and (iii) increase emissions from the power plants of the electric utility that the emissions per capita in Cyprus increased by almost

[91] Step by step method for solving single - objective optimization problem is explained by Mazer (2007), in Chapter 5: A simplified Look at Generation Capacity Addition". In this paper, a robust formulation for the multi-objective problems will be developed for an improved solution with simplification in order to avoid complicated engineering and technical details.

[92] Although we will not discuss the pros and cons of renewable incentive programs in this research chapter, renewable power incentives such as FITs scheme is based on energy output of particular renewable energy source (MWh) but on the amount of CO_2 emissions reduction by the renewable energy source. This is quite different than carbon pricing paid by "dirty" power sources, for example carbon pricing is not biased toward any technology and kwh of carbon payments depend on carbon intensity of the fuel to generate kwh of energy.

20% between 1990 and 2010 and (iv) will leave the island one of the most vulnerable in terms of security of energy supply due to the isolated characteristic of the Cypriot electricity network (European Commission, 2013; Pilavachi *et al.,* 2009). Then, it becomes apparent how important it is to introduce renewable energy sources (RES) to the Cyprus energy system to reduce costly dependency on fossil fuel imports for electricity generation, diversify the energy mix for security of power supply reasons, and reduce emissions from electricity generation.

The major aim of this chapter is to quantify the impacts of wind and solar power penetration on the electricity expansion and generation in Cyprus as well as to investigate the economic costs of renewable energy regulations on the electricity sector. To do this, we examine wind and solar renewable power sources on the basis that electricity generated from these sources is used alongside generation from conventional plants. We initially build a theoretical model where the objective is to minimize the weighted sum of economic cost and pollutant emissions from electricity generation with a mix of renewables given the set of constraints. We apply the model to assess the economic and environmental impacts of an integrating mix of wind and solar power on the Cypriot power supply. The model presented in this paper can be applied to any isolated power system and can help regulators to assess the economic costs of integrating renewables into grid.

2.2 Literature Review

2.2.1 Theoretical Literature

One of the widely applied standard methods in electricity generation planning is to compare the economic performance of the power plant technologies by the *levelised cost of electricity* (LCOE)[93]. It

[93] See Lazard (2009) estimates the levelized cost of energy comparison for conventional and renewable plants. LCOE estimates, however, for even for the same technology vary country from country, output depends on intensity of renewable source (wind speed, solar radiation level), and costs depends on site specification, distance from plant to national grid, cost of financing, etc. Note that energy from renewables such as from wind and solar depend on wind and solar intensities, so there is no universal LCOE for renewables, at least for wind and solar.

is calculated by dividing the present value of total life cycle costs of a power plant (€) by the present value of electricity produced over the system life by the same power plant (MWh) (Campbell et al., 2009). Therefore, the LCOE tells us the cost of producing a MWh of electricity by the power plant if costs are equally distributed over power production in a year. The use of LCOE is inappropriate with a mix of renewables due to reasons including (a) the load serving capabilities (peaking load vs baseload) of power plants are different, (b) power generation from many renewable sources such as wind and solar is intermittent and non-dispatchable[94], (c) estimates fail to capture the integration costs of renewables on the overall system that are not negligible, and (d) estimates are in favour of less capital intensive plants at high rate of return but wind and solar power are both highly capital intensive investments (Awerbuch, 2005; Marcantonini and Parsons, 2010)[95]. The LCOE estimates must include market value as well as monetised values of net environmental externalities and financing from renewables, so we need more sophisticated levelised cost estimates in order to capture the true benefits and costs of electricity generation from renewables (Borenstein, 2012). However, the LCOE estimates can be a useful tool to design the renewable support policy such as setting up the feed-in tariff for renewable electricity[96]. In addition, levelised cost can be regarded as a breakeven price for generators that leaves them with zero profit and can be used to compare the costs of different power technologies serving the same load (e.g. coal and combined cycle gas turbine for baseload, single cycle turbine and diesel generators for peak load demand).

[94] Intermittency is defined as variability in power output or uncontrolled changes in output. For instance, wind and solar power is variable with a changing wind speed and sunlight. Dispatchability is defined as ability of a given power source to increase and/or decrease output quickly on demand. For instance, wind and solar power sources must be used at the time wind and sun rise as power produced now cannot be used for the next minute. The intermittency and non-dispatchable nature of renewables are not the same across renewables and vary greatly between them.

[95] Also see Joskow (2011) and Borenstein (2011).

[96] The feed-in tariff premium payment consists of the purchase price and an additional payment to cover the difference between the purchase price and the guaranteed tariff – paid by consumers. The application of this price regime is different across countries and across renewable energy sources. For instance, the feed-in tariff is linked to the oil price and set by the Cyprus Energy Regulatory Authority (CERA).

Policy makers also apply a *screening curve* approach to determine economically optimum levels of capacity to meet the demand for electric power for a given year (Kelly and Weibung, 1993; Shaalan, 2003). With this method, electricity demand is represented by a cumulative distribution function of the load in a given year and the curve is called the load duration curve. With this method, cost curves of individual power plants are plotted against the load curve to determine the optimal generation mix to supply different load demand if power plants are dispatchable (Stoft, 2002). Therefore, the screening curve approach may not be suitable to determine optimal installed capacity with wind and solar power integration as they are both non-dispatchable generators[97].

When the screening curve approach is used with renewables, residual demand is derived by subtracting renewable power from the load demand, so wind and solar power sources are both treated as a negative load in optimization to investigate the impacts of the renewable integration on the power system. The screening curve approach simplifies the intermittency of electric power from renewable sources. Finally, wind and solar power are not decision variables in this approach as they are assumed to be "already committed" power plants. Despite all the above, the screening curve approach is a useful tool to analyse investment decisions both under traditional integrated utility and competitive markets (Green, 2005). We can adapt the screening curve approach in order to analyse the benefits and costs of renewable power integration as in (Kennedy, 2005; Lamont, 2008; George and Banerjee, 2011), impacts of renewables on electricity prices as well as on generating capacity as in (Green and Vasilakos, 2011).

Optimization models (simulation models) are used to analyse the impact of renewable power on electricity generation and planning decisions. These models are helpful to solve complex mathematical functions described within multiple objective functions subject to a large number

[97] Olsina et al. (2007) claim the same argument with different reasoning.

of constraints. The use of optimization models depends highly on details of information the researcher would like to obtain from the analysis. In the past year, the principal problem of the electric utilities has been to minimize the generation costs (objective function) subject to different levels of system and regulatory constraints (constraint functions) where both functions are linked to the length of time being considered. Therefore, the system planners use different optimization tools to solve the problems occurring at different time horizons (Mazer, 2007). In the literature, the time horizon is divided into three phases for a traditional integrated utility: short term, medium term and long term in which they are interdependent of each other. The electric utilities are faced with different constraints in each time horizon; therefore there are different solution mechanisms for each of the problems.

1. The short term or ***economic dispatch*** (ED) problem is related to the allocation of the existing generators to meet the real time electricity demand at the lowest cost possible (efficient resource allocation problem within seconds to hours).
2. The medium term or ***unit commitment*** (UC) problem is related to scheduling of the existing generators to minimize the cost in time (efficient scheduling problem within days to a week).
3. The long-term or ***capacity expansion*** (CAPEX) problem is related to capacity and to the number of power generators a system should own in the future to minimize the cost (over a number of years).

In this research, we simultaneously incorporate (1) economic dispatch model (optimal dispatching) and (3) long-term capacity expansion problem (optimal stacking) to determine optimal quantities of energy (MWh) and capacity (MW) so that we minimize sum of total electricity generation costs and expansion costs in energy system[98]. Solutions to the problems are straightforward if we are dealing

[98] We explained the model in great detail in section 2.4 of this chapter.

with a single objective function in electricity generation and expansion that is the minimization cost. We will not go deeper into the single optimization models, but Mazer (2007) and Anderson (1972) provide details for each. Solving the multi-objective problems are difficult tasks because of the complexity of each problem arising from the following:

a. ***Conflicting Objectives:*** Power plants emitting less are relatively expensive (combined cycle with natural gas) than others, and vice versa (coal plants). Hence, emission reduction maximization and economic costs minimization are two conflicting objectives.

b. ***Heterogeneous Power Sources:*** Unlike conventional power plants, most of these renewable power sources are both intermittent and non-dispatchable.

c. ***Shift from Monopoly to Competition:*** Invalidation of "*ceteris paribus*" assumption due to: greater uncertainty in market and market prices; utilities must consider consumer response to price change; utilities must take into account the actions of other suppliers; and electric utilities must have a better understanding of their cost structure (Hobbs, 1995).

The model we will apply in this paper is a multi-objective optimization problem that combines both economic costs and environmental emissions from electricity generation. Given these objectives, potential societal losses from electricity generation can be minimized when the model is applied in a consistent manner (Mazer, 2009). The most relevant models in the literature include: Hobbs (1995); Lineras and Romero (2000); Antunes *et al.* (2004); Meza *et al.* (2009); Tekiner *et al.* (2010); Kourempele *et al.* (2010); Muis *et al.* (2010)[99]. Alternatively, social welfare

[99] Each of these authors uses a different solution algorithm in their models. We will use solution method followed by Mavrotas (1999). For more details, see section four of this paper. At the same time, welfare maximization can be also used, and relevant literature include Bushnell (2010), Green and Vasilakos (2011b), De Jonghe (2011) and Hirth (2012).

maximization can be applied such as models depicted by Bushnell (2010), Green and Vasilakos (2011b), De Jonghe (2011) and Hirth (2012).

Hobbs (1995) provides theoretical approach to solve multiple criteria of long term resource planning that involves economic (costs), environment and social criteria simultaneously. He clearly states the advantages of using multiple criteria from two perspectives: (a) clarifying the trade-off between conflicting objectives for value judgement and (b) quantifying the priorities for different stakeholders involved in resource planning. Hobbs (1995) considers sources of uncertainties in his model such as market (demand) uncertainties as being high frequency short term uncertainties, while resource uncertainties together with the legal and economic uncertainties are low frequency long – term uncertainties. In addition, the adjustments for the same problem for the competitive market are also clarified by Hobbs (1995). The theoretical model for renewables is not discussed in his paper.

Linares and Romero (2000) integrate dispatching costs together with the environmental damages in a multi objective model setting. Not only pollutant emissions from electricity generation but also the productions of radioactive wastes are included in the environmental impacts. To get compromise solutions from the model, they estimate the weights to be assigned on each objective function[100]. They apply the model and this weighting method to the Spanish power to get Pareto-efficient solutions. In this model, authors did not acknowledge the economic impacts of renewables on electricity generation and planning.

Antunes *et al.* (2004) defines the problem as mixed integer linear programming with three objective functions including the expansion cost, a measure of environmental impact from

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[100] These weights actually depend on the regulator's choice and are assigned to each objective function. Because we do not now these weights, we use ε - constraint approach that involves minimizing a primary objective (cost) and expressing the second objectives in the form of inequality constraints (emissions). This approach allow us to create pay-off table with only Pareto optimal solutions. Algorithm details of the model is explained in in Mavratos (2009), Effective implementation of the e-constraint method in Multi-Objective Mathematical Programming problems, *Applied Mathematics and Computation*, 213:455–465

expansion and the monetized environmental impact of the energy output. In their model, peak clipping (peak shaving) is modelled in the planning process as being a demand side option. They apply a scalar function in order to obtain non-dominated optimal solutions that are given as non-negative weighted-sum of the multiple objective functions.

Muis *et al.* (2007) develop an optimization model for electricity generation planning with renewables with a carbon dioxide (CO_2) target and a regulator's constraint such as a renewable target. In their model, carbon dioxide (CO_2) emissions are written in the constraint function that implies the use of ε - *constraint* as solution approach. In this model, the authors did not acknowledge the economic impacts of wind power on electricity generation and planning, but solar was under consideration.

Meza *et al.* (2009) integrate many conflicting objectives in their model but reduce the problem into a single period. They provide a model with four objectives all being minimization problems: cost, environmental impact, imported fuel and fuel price risk subject to system and regulatory constraints. The key element of their model is that it is realistic and useful especially for large utilities with many interconnections and variety of demand nodes. However, none of the renewable sources of power supply is investigated in their theoretical model.

Tekiner *et al.* (2010) integrate reliability, expansion and dispatching decision in a multi objective model using simulation technique. The objective is to minimize the total expansion cost and emissions over multiple periods. The main distinction from other studies is that they incorporate multiple sources of pollutants in their model such as carbon dioxide (CO_2), nitrogen dioxide (NO_x) and sulphur dioxide (SO_2) emissions. In order to solve the problem, they apply a scalarizing function approach. The only renewable source of electricity supply considered in their model is wind, but dispatching results are not studied explicitly in the paper.

Kourempele *et al.* (2010) develop a multi – objective electricity expansion model for an isolated power system (Milos Island of Greece) considering demand constraints, and power generation and capacity constraints. The objective function includes both cost minimization and maximum reduction in emissions from electricity generation. In their model, both wind and solar power sources are included with technical boundaries in the model. However, regulatory constraints are not modelled, although they are highly influential on the outcomes.

In addition to the models described above, Nagl *et al.* (2012) develop a theoretical stochastic model in order to estimate the impacts of increasing renewable power sources on both investment and dispatch decisions for the future European single grid. The objective is to minimize total discounted economic costs subject to demand, reliability, generation and renewable electricity generation constraints. The stochastic nature of the model is modelled by assigning weights (scenario probability) to each of the scenario undertaken. The key contribution of their model is that they evaluate a mix of wind and solar power including feed-in structure. The uncertain nature of wind and solar is captured with scenario estimates and possible export and imports of electricity between countries are modelled.

Bushnell (2010) develops an equilibrium model of electricity investment in order to assess impacts of intermittent sources of power supply on generation mix, peak vs. off-peak thermal plants investments and power prices where the market is operating under competitive environment with capacity market. Two key contributions of his model are that wind power is included in the system due to regulatory policy constraint and the short term impacts of demand response to price changes on the generating mix are included.

Green and Vasilakos (2011b) develop a theoretical model aiming to capture the long-term equilibrium prices as well as generating capacity with and without wind integration for both competitive (social welfare maximization approach) and oligopoly market structures (supply function equilibrium approach). The model maximizes the social welfare under system generating and regulatory constraints with the wind power. The key contribution of their model is that impacts of short-term demand response in electricity prices on power generation capacity selection can be compared for the two market structures in question and relative impacts of wind integration on electricity consumers and producers (renewable and non-renewables) can be estimated for comparison purposes[101].

2.2 Applied Literature on the Economics of Renewables

Previous studies in the literature, dealing particularly with renewable power integration, include impacts on power supply mix, power supply reliability, power markets potential on power prices and its environmental impact. This section reviews the most relevant contributions.

Potential economic benefits generated from renewable energy sources are estimated using capacity factor (energy savings in MWh) and capacity credit (capacity savings in MW), respectively. In addition to these economic benefits, most renewables contribute to the environmental quality as they are emission-free technologies (Lund, 2004; Delarue *et al.,* 2009, Akella *et al.,* 2009). The social value (sum of economic and environmental benefits) generated from a particular renewable energy source are in the form of energy savings, fixed cost savings, capacity savings and emission savings net of grid-level system cost. The economic value of a renewable energy source heavily depend on the time when it is produced, its penetration in the system (Holttinen *et al,*. 2011; Touhy *et al.,* 2009), and characteristics of the supply mix such as fuel mix and system flexibility and correlation between renewable source and system load as well as forecast error (Lund and Munster, 2003; Hirst and Hild, 2004; Lund, 2005; Bode 2008; Denholm and Han, 2011, Lew et al., 2011).

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[101] For instance, Green and Vasilakos argue that the effect of a large amount of intermittent generation (wind power is to be a major source) in the UK power mix will increase the level of price volatility in the wholesale market and result in considerable variations in annual profits of the power generators. However, prices be will be more than doubled together with an increase in their volatility and revenues of the power generator will be greater together with greater in their variability if electricity market is a duopoly.

Furthermore, long-run potential economic and environmental savings depends on expected change in demand for energy (changes in the shape of load curve over-time), future changes in fuel prices (relative changes between prices of fuel, gas, and coal) that are reflected in slopes of the thermal supply curves and ultimately affects the size of merit-order effect of renewable generation (Sensfuß *et al.,* 2008; Sensfuß *et al.,* 2007), and long-term impacts of renewables on optimal thermal-renewable mix (De Miera *et al.,* 2008). Therefore, the actual costs paid and benefits generated from RES investments are different across countries with different demand and supply characteristics (Ferguson-Martin and Hill, 2011; Doherty *et al.,* 2005; Lund, 2005; Kennedy, 2005; Warsono *et al.,* 2007; Holttinen, 2008).

Capacity factor is the capability of the renewable plant to generate electric energy (in MWh) during a typical year. Renewables are low marginal cost plants with zero fuel cost, so they are the first dispatched generators in the system (Kabouris and Vournas, 2004; Singh and Erlich, 2006). In turn, renewable power sources when they are integrated into the power supply displace energy from conventional thermal plants by lowering the load demand the thermal system has to supply. Hence, adding these renewable sources generate savings in the form of a reduction in the variable operating costs (mainly fuel) and emissions from conventional electricity generation. The well accepted conjecture is that integration of wind and solar power (intermittent and non-dispatchable renewables) is economically feasible when the monetary value of savings in fixed and operating costs net of the overall system cost of integrating these renewable plants is positive.

Capacity credit is the amount of conventional generation capacity (in MW) that is replaced by the renewable generation while system reliability is maintained. Renewable power may create capacity value to the power system if the renewable output profile matches with times of high system load

(Grover, 2007), otherwise a high share of renewables with no coincidence of peak demand might increase optimal peak and mid-load capacity in the long-run (Lamont, 2008; Usaola *et al.* 2009; DeJonghe *et al.* 2011)[102] . Studies estimating the capacity credit from renewables for evaluating the economic value of electricity generation from renewable sources show that the capacity credit from renewable source decreases as penetration increases (Mills and Wiser, 2012; Lamont, 2006; Giebel, 2005; Holttinen, 2004; ESB National Grid, 2004; Van Wijk *et al.,* 1992). The possible solution for the electric utilities to earn greater capacity credit might be decentralizing wind farms across different nodes (Chowdhury, 1991; Dincer and Rosen, 2005)[103]. However, decentralizing cannot be an option for a small island as wind speed or sunlight profiles do not vary greatly across small islands plus the fact that land in these small islands is an extremely scarce commodity for renewable investments. The use of capacity credit as an indicator for the assessment of economic value from renewables is questioned as MW to MW replacement does not exist with renewables (Holttinen, 2008).

Ecological, health and productivity costs attached to the emission pollution generated from conventional electricity generation is one of the reasons for increasing the share of renewables in the energy mix including electricity generation, predicating government support and stringent environmental regulations (Bilen *et al.,* 2007; Boccard, 2010; Kaffine *et al.,* 2011 Hinrichs-Rahlwes, 2013). When these environmental externalities are included in the cost estimates, especially GHG emissions, the gap LCOE from renewables against thermal generators gets smaller (Varun *et al.,* 2010), for example inclusion of damage costs increase competitiveness of renewables against coal generators (Owen, 2006). The conjecture is that electricity generation from renewables will help us deal with problem of rapidly increasing global greenhouse gases and reduce local air pollution from electricity generation (Tsoutsos *et al.,* 2005; Lior, 2010; Friedman,

[102] See screening curve analysis, Usolar et.al (2009, p.5)
[103] For countries where decentralization can be an option we should also take into account the increase in the cost of transmission as well as transmission losses which reduces the economic benefits from renewables.

2011; Bergman and Hanley, 2012), so that they contribute to the sustainable development of human activities[104]. This is why conventional plants may pay a tax for the emissions they create and renewable plants receive a subsidy from their output partly due to strong public support[105]. The economics behind this intervention is to minimize the negative externalities associated with electricity production that allows electricity production from power plants to converge to its socially optimum level.

Kim (2007), for example, argues that valuing the externalities generated from electricity generation and including them in energy prices allows policy makers to achieve economically efficient allocation of power generation resources. However, non-market costs including visual and/or noise irritations for residents and visitors are also considered as being part of negative externalities (Bergmann *et al.,* 2006; Moran and Sherrington, 2007). When these negative externalities are included, the value of renewable power is partly reduced (Mirasgedis *et al.,* 2000; Toke *et al.,* 2008). However, the inclusion of all environmental, health and non-market costs can provide true feedback from public opinion and can also be integrated into the decision – making process[106].

[104] The effects of environmental quality on property prices are studied in the hedonic property value studies and air quality literature, formalised by Rosen (1974). For example, Davis (2011) adjust for differences across locations in observable power plant emissions, demographic and housing characteristics across regions in the US and show that housing values and rents drop between 3%–7% if property is located within 2 miles of a power plant, and reduction is significantly higher if the distance between property and power plant gets closer. Thus the location of property and its proximity to source of pollutant emission is a key driver of real estate values suggested from survey of research by Boyle and Kiel (2001). Chay and Greenstone (2005) employ an instrumental variable approach to demonstrate the impacts of concentration of particulate matter (PM) on housing values across the US and they show that elasticity of housing values with respect to concentrations of particulates ranges between -0.20 to -0.35. Hence, we can conclude that air quality matters for individuals and they actually price it high.

[105] These subsidies are not same across countries and renewable energy sources. Although solar renewable source is more abundant than wind in Cyprus, solar PV subsidies are larger than wind subsidies. Subsidies to promote renewable energy production ($/kWh) depend on particular renewable source and mainly variables such as cost components including capital costs, operating and maintenance costs ($), and output that is a function of renewable source abundance (wind speed, solar radiation level).

[106] For instance, UK experienced Campaign to Protect Rural England (CPRE) against wind farm in rural areas of UK, organized by landscape protection organizations in the country, for more details see Toke *et al.,* 2008.

Considering renewables purely as a fuel and carbon saver as in (Manwell *et al.,* 2002), 'it would be nothing more than 'overestimating' the benefits or 'underestimating' the costs associated with renewable power integration because of the 'intermittent' and 'non dispatchable' nature of renewable such as wind power' (Olsina *et al.,* 2007). Maintaining the power supply reliability requires the reserve requirement due to the unexpected change in demand for electricity or unexpected power outages (Allan, 1989; Doherty and O'Malley, 2003; Dena, 2005; Sinden, 2007). Studies dwelling only on power supply reliability with renewable power integration suggest that electric utilities must keep an additional operational reserve in order to maintain the power supply reliability due to the intermittent nature of renewables (Holttinen and Hirvoven, 2005; Doherty and O'Malley, 2005; DeCarolis and Keith, 2005; Karki and Billinton, 2006; Smith *et al.,* 2009, Boqiang and Chuanwen, 2009; Mills and Wiser, 2010). In addition, the electricity grid must contain flexible thermal capacity so that system can cope and to ensure supply reliability with intermit renewable electricity (Lund and Munster, 2003; Lund, 2005; Henkel et al., 2008; Jacobsen and Zvingilaite, 2010; Steggals *et al.,* 2011).

The precise argument is that electric utilities incur additional costs with an increasing renewable penetration in the system (Auer *et al.,* 2004; Smith *et al.,* 2004; Strbac *et al.,* 2007; Georkilakis, 2008; Holttinen *et al.,* 2009). Hence, the reliability cost ultimately increases the marginal cost per MWh of electricity production from renewables that reduce the benefits from integrating them and will be reflected in higher electricity prices (DeMeo *et al.,* 2005; Millan and Porter, 2005; Strbac *et al.,* 2007; MacCormack *et al.,* 2008). The renewable plant may contribute significantly in the reliability of the system if it replaces the peaking plant (Kirby *et al.,* 2003) because back-up costs tend to decrease with respect to capacity credit earning (Cavallo, 1995; Green and Vasilakos, 2011a). At the same time, we believe that a renewable power source with low marginal costs creates more competition in the power market so the variability of the renewable power may not be a problem in the short term since existing less efficient plants become the reserve capacity.

Empirical studies investigating the impact of renewables on electricity prices reveal that promoting renewables both enhances the competitiveness and lowers the electricity prices in the power market with the fossil supply curve sloping upward – due to the merit order effect of renewables (Amundsen and Mortensen, 2001; Jensen and Skytte, 2003; Bode, 2006; De Miera *et al.,* 2008; Butler and Neuhoff, 2008; Weigt, 2008; and Fischer 2006; 2009). The argument is that low marginal cost renewables force high marginal cost plants out of the system so consumers enjoy the lower electricity prices they pay reflected as higher consumer surplus. It also allows countries to diversify their fuel mix so that vulnerability of their economies to the price volatility of fossil fuels is reduced (Awerbuch and Sauter, 2006). The ex-post studies show that impact of the renewable power on electricity prices depends on when the particular renewable source produces its electricity during the day (Sensfuß *et al.,* 2007; 2008), the structure of the power market such as number of market participants and degree of market power (Green and Vasilakos, 2010b) and also depends on the marginal increase in electricity production from renewable power sources (Gelabert *et al.,* 2011; Twomey and Neuhoff, 2010). At the same time, penetration of renewables might decrease the price of electricity from a lower demand for fossil fuels and demand for carbon permits (Rathmann 2007). Thus the integration of renewables is successful, one way of seeing renewable electricity is that it hedges against fuel price fluctuations as it may actually stabilize the electricity costs in the market.

Renewable power producers often sell their electric power at minimum guaranteed feed-in-tariff rates, which facilitated renewable investments including wind and solar PV in the EU (Jenner *et* *al.,* 2013)[107]. This is because investors are not able to cover the high capital cost from market prices without a fixed premium they receive on their output, so incentives result in larger deployment of renewables (Fabree et al. 2005; Munksgaard and Morthorst 2008; Mulder 2008). Among renewable support schemes, the price – based instruments such as feed in tariff (FIT) policies are applied, on the whole, as they are believed to be economically efficient (EU Commission 2008; Butler and Neuhoff 2008; DeMiera et al. 2008; Del Rio 2010)[108]. The cost of renewable support is reflected in the retail power prices consumers actually pay, however. This issue increases the concern about the costs of integrating renewable sources and intense debate in the political and academic arena.

The market value of renewable electricity generation net of the subsidy paid to renewable generators derives its benefits or costs to the consumers. To put it simply, power costs for consumers decrease with renewable support so that consumers do not bear the full burden of the financial cost of renewable energy mark-up as in Germany (Bode, 2006; Sensfuß *et al.,* 2008); in France (Jensen and Skytte, 2003); in Spain (De Miera *et al.,* 2008), but consumers' bills increased from renewable subsidy programme in Scotland and in the UK (Bergman and Hanley, 2012). Although investments in renewables are still highly costly, they are experiencing substantial cost reductions over the last decade due to renewable technology push policies (Junginger *et al.,* 2005, Stern, 2007). Therefore, the need for adjusting the renewable support instruments with respect to cost reductions due to the development of renewable technologies, as in the feed-in tariffs currently used by 19 EU member states, is well acknowledged (Del Rio and Bleda, 2012; Bergman and Hanley, 2012; Teckenburg *et al.,* 2011).

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107 See Frondel *et al.* (2008) and Frondel *et al.* (2010). The first paper discusses spending, particularly on solar PV, in Germany, and the second paper argues that renewable policies are not cost-effective for climate change protection and employment creation in the German case.

108 The importance of harmonization of national renewable policies between the member states is also perceived by the EU (Munoz et al., 2007), but European Commission (2008) points out the fact that the current barriers renewable technologies face with and low competition in the European electricity market postpone the desire of long – term objective of the harmonization of the RES support programs across the EU member states.

The feedback effect that the reduction in power prices due to the renewable integration negatively affects the electricity generation from non-renewables and alter the future investments in non-renewables (Olsina *et al.,* 2007; Obersteiner *et al.,* 2008; Jacobsen and Zvingilait, 2010) Renewable penetration may also increase the volatility in hourly prices in the short term as power from renewables fluctuates during the day – but the impact of fluctuations in wind speed on power prices might be smaller than the impact of the fluctuations in fuel prices on power prices. Hence, this may or may not result in a greater uncertainty in the market and increase the costs of operations from conventional units. Not only price risk, but large amounts of intermittent and relatively unpredictable renewable power (at least wind) in the generation mix also increases the market risks for conventional generators as it increases the price volatility as well as creates greater uncertainty in the output they supply – that is residual load (Fabbri *et al.,* 2005; Steggals *et al.,* 2011). This in turn may discourage future investments in thermal generators that already face fuel price volatility in their operations (Traber and Kemfert, 2011; Steggals *et al.,* 2011)[109].

In fact, thermal power suppliers will tend to invest more in low-capital cost peaking plants with short payback periods (Denholm and Han, 2011; Euroelectric, 2011; Jensen and Skytte, 2002). Since renewables reduce the capacity factor of thermal plants, average costs tend to rise for thermal generators. Hence, the profitability of thermal generators depends highly on prices they receive during the hours when there is no or very little renewable power. Renewable electricity with low variable costs (almost zero) and uncertain output reduces the load that thermal generators supply and affects wholesale power prices through thermal displacement. Thermal

[109] Therefore, impacts of adding renewables on current as well as future thermal investments is also important to take into consideration for energy policies. MacCormack *et al.* (2010) evaluate the large–scale integration of wind penetration in a deregulated market and its impacts on market prices, overall reliability of supply and revenues and costs of dispatchable conventional suppliers. They also argue that eventually, the reliability issue will necessitate re–structuring the optimum mix of power plants in the very long-run.

power suppliers pay for the renewable support scheme by receiving less for their supply so reducing their profits.

The impact of carbon prices on wholesale prices is clear: it increases the cost of electricity depending on the generation mix with heterogeneous emissions. Thus, the additional cost of electricity from coal, oil and other forms of fossil fuel further make renewables economically viable and cost-competitive per kWh energy. RES sources reduce the demand that thermal plants have to supply, and so will reduce emission allowance prices from the reduction in demand for emission permits.

Finally, from the available literature, we can conclude that the price impacts of renewables depend mainly on the level of renewable power penetration in the system, in other words, there should be a large enough amount of renewable generation to alter the market prices (Hart and Jacobson, 2012; Weigt, 2009). Secondly, wind and solar sources of power are intermittent power sources, so the impact of adding renewables on power prices, depends greatly on which hours the renewable power source becomes available and therefore precisely its impact on price setting power plants (Hirth, 2012; Morthorst and Awerbuch, 2009; which Sensfuß *et al.,* 2008; Lamont, 2006). Thirdly, integration of renewable sources influences electricity prices differently across power market structures, and depends precisely on how the market is structured (Green and Vasilakos, 2010; Delarue and D'haeseleer, 2005). Fourthly, future changes in fuel prices (relative changes between prices of fuel, gas, and coal) and CO_2 prices that are reflected in slopes of the thermal supply curves and ultimately affects the size of merit-order effect of renewable generation (Sensfuß *et al.,* 2008; Sensfuß *et al.,* 2007). Finally, impacts depend on the system specific demand profile and supply characteristics of the plant mix (Bode, 2008; Anderson, 2007; Bode, 2007).

2.3. Electricity System in Cyprus[110]

2.3.1 Supply of electricity in Cyprus

Cyprus has a small and isolated electric supply system with a total nominal installed power capacity of 1,448.5 MW as of December 2011, of which installed wind power capacity is 102 MW (Transmission System Operator of Cyprus, 2010). With the exception of wind farms, all power generation units are owned and operated by the Electricity Authority of Cyprus (hereafter EAC). The EAC acts as the monopoly provider of the grid based non-renewable electricity. Therefore, the electricity market currently has no competitive wholesale and balancing markets in its operations. Existing conventional generators in the Cypriot grid are running solely with heavy fuel oil and gas oil. The conventional electricity generation mix includes gas turbines, steam turbines and combined cycle gas/ oil plants as of January 2012. These power plants are to be: gas turbine (peaking plant – least fuel efficient), steam turbine (intermediate load plant – second least fuel efficient) and combine cycle gas turbine (baseload – fuel efficient). There are three power stations In Cyprus, namely Moni, Dhekelia, and Vasilikos (see Figure 2.1). Total installed capacity in Cyprus is 1218 MW (see Table 2.2). The economic and technical data for the existing power plants are presented in the tables in the Appendix A and Appendix B.

In terms of air pollutant emissions from electric power generation in Cyprus; carbon dioxide (CO_2), nitrogen dioxide (NO_x) and sulphur dioxide (SO_2) emissions are considered such that the electricity sector represents 20%, 36%, and 62% of total NO_x, CO_2 and SO_2 emissions in Cyprus as of 2002, respectively (Tsilingiridis *et al.*, 2011). The reported coefficients are given as tonnes of CO_2, NO_x and SO_2 emissions produced per MWh of conventional electricity generation from each power plant. Therefore, emissions savings from renewable generation vary substantially and depend on the fuel source displaced by wind and solar power. Currently, the EAC has emission

[110] Analysis for the island completely excludes the northern part of the island.

permits for all of its power stations, where the emission permit costs are reflected in electricity prices paid by the consumers. In addition, the EAC is subject to the emission limitation commitment as ratified by the national government of Cyprus. As of 2011, the country's electricity generation comes almost all from imported oil sources. For the purpose of comparison, the emission levels for Malta and Cyprus are provided in Table 2.1 below where both countries generate electricity from fuel oil sources and both have an isolated power system.

Table 2.1 Environmental Indicators of Cyprus and Malta[111]

Selected Environment Indicators	Cyprus	Malta
Total Surface Area (km^2)*	9,250	320
Total Population (2007)*	1,063,095	406,724
Total GDP (2007)*	21,841,815,680	7,513,834,699
CO_2 emissions (millions of tonnes)$^+$	8.2	2.73
% change (1990 to 2007)$^+$	76.2	25.3
CO_2 emissions per capita (tonnes)$^+$	9.6	6.71
CO_2 emissions per km^2 (tonnes)$^+$	886.28	8639.24
CO_2 emissions per unit of GDP (kg/$1,000 of 2005 PPP $)-	410.2	274.3

Sources: * World Bank Indicators, Online Library, http://data.worldbank.org/indicator
+ Environmental Indicators: Greenhouse Gas Emissions in 2007, UN, (July 2010)[112]
- The Little Data Book on Climate Change, World Bank (2011)

Note that natural gas has recently been discovered in Cyprus; electricity generation from natural gas will assist in the diversification of electricity generation fuel along with renewable energy sources (Cyprus Energy Regulatory of Authority, CERA 2011). Natural gas supply is expected to arrive to Cyprus in 2015 and ambitious plans are being made to use it for electricity generation (Energy Efficiency Policies and Measures in Cyprus, Cyprus Institute of Energy, 2009). The combined cycle units currently running with diesel oil are expected to be converted to generate

[111]For the changes in emission intensity of public conventional thermal power electricity and heat production from 1990 to 2008 across EU member states, see the public information made available by European Environment Agency, http://www.eea.europa.eu/data-and-maps/indicators/emissions-co2-so2-nox-intensity-1/assessment-1
[112] See http://unstats.un.org/unsd/environment/air_co2_emissions.htm

electric power with natural gas. Based on this expectation, all candidate conventional systems in this study are assumed to be running with natural gas rather than fuel or gas oil. The financial and economic data for the candidate natural gas fired plants are from capital cost estimates for electricity generation, prepared by the US Energy Information Administration (2011).

In this chapter, technologies for electricity generation such as nuclear, coal, and oil-fired plants are not considered as competitive options. This is due to national target of utilising renewables (wind and solar) and investing on conventional plants running with the natural gas in energy mix of the island (Cyprus Energy Regulatory Agency, CERA, 2013; Henderson, 2013; Rodoulis, 2010). The main reasons for such rational decision is the discovery of less pollutant emiting natural gas resources in the east Mediterranean around the Cyprus and the decline in costs of renewable power supply options dramatically. These two will shift energy focus away from OPEC oil countries in Cyprus. As previously stated, electricity generation costs are already high and emissions from electricity generation is a concern of the government; and because of high CO_2 emission intensity and other negative environmental impacts of burning heavy fuel oil and coal together with high costs of importing them make them financially and environmentally unattractive for Cyprus Island. In fact, these two reasons increases the attractiveness of mix of natural gas and renewables for electricity generation in addition to security of power supply benefit from this mix[113].

It is crucial to estimate the fuel consumption of a power plant carefully as this is the greatest share in benefits from renewables in the form of fuel and emission savings. Fuel efficiency of power plants is compared with respect to thermal efficiency and fuel consumption in the generation of electricity. In this chapter, the tonne/MWh of fuel consumption for existing power

[113] Darbouche, H., El-Katiri, L. and Fattouh, B. (2012). 'East Mediterranean Gas: What Kind of Game Changer?', Working Paper NG 71, Oxford Institute for Energy Studies, December 2012.

plants is estimated using historical fuel consumption and production data. For candidate natural gas fired plants, we estimate gas consumption assuming the following efficiency levels.

Table 2.2 Fuel Consumption Estimates for Candidate Gas – Fired Plants

Plant Type	**Overall Thermal Efficiency (%)**	**Heat Rates (Kj/kWh)**	**Fuel Quantity (m3/MWh)**
Baseload Combined Cycle	58%	6207	144.35
Medium Load Gas Turbine	45%	8000	186.05
Peak Load Gas Turbine	34%	10588	246.24

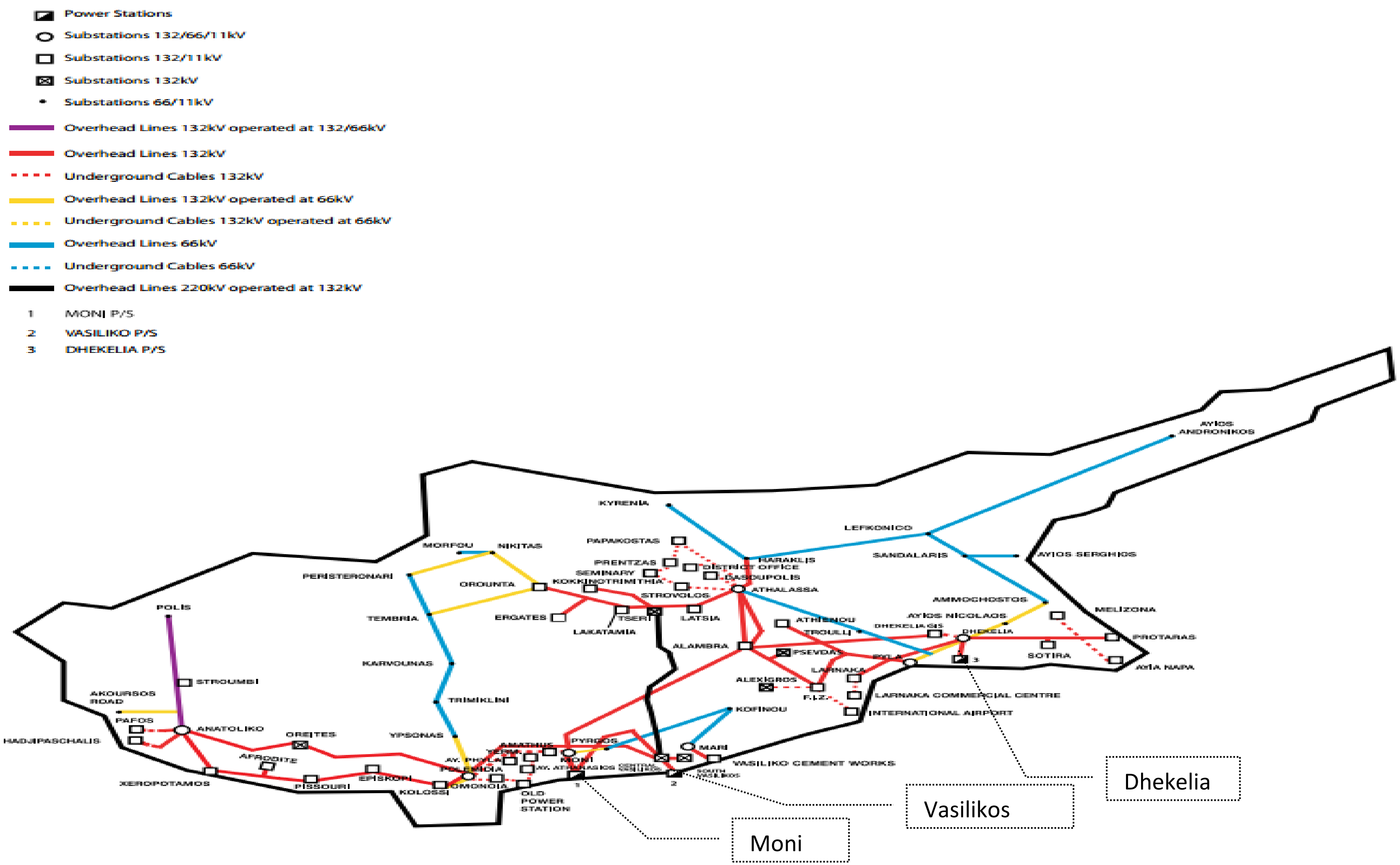
* Heating value of natural gas is assumed to be 43,000 Kj/m^3

2.3.2 Demand for electricity in Cyprus

Electricity retail prices including taxes and network charges in Cyprus are currently very high, so much so that they are the 4th highest in the EU at an average rate of 0.229 euros per kilowatt-hour as of 2014 - so at this rate consumers pay about 10% more than average EU citizens pay for their electricity consumption (Eurostat, *Energy Price Statistics*, 2014). As of 2014, the basic price in Cyprus that excludes taxes and network charges (i.e. electricity generation cost) are still the highest in the EU, however. (Eurostat, *Energy Price Statistics*, 2014)[114]. Demand for electricity in Cyprus has been increasing steadily at about 6% per year from 2000 to 2010, however. Therefore, this increase in demand for electricity will bring additional fuel consumption and capacity additions to supply this increase in energy demand[115].

[114] See: http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_and_natural_gas_price_statistics
[115] For more information: http://ec.europa.eu/energy/energy_policy/doc/factsheets/mix/mix_cy_en.pdf

Figure 2.1 Power Generating Stations, Substations, Transmission and Distribution Lines in Cyprus



Source: Electricity Authority of Cyprus, 2013 Annual Report, www.eac.com.cy/EN/EAC/FinancialInformation/Documents/AHK%202013%20ENGLISH.pdf

Table 2.3 Energy Mix of Cyprus by Station and Plant Type

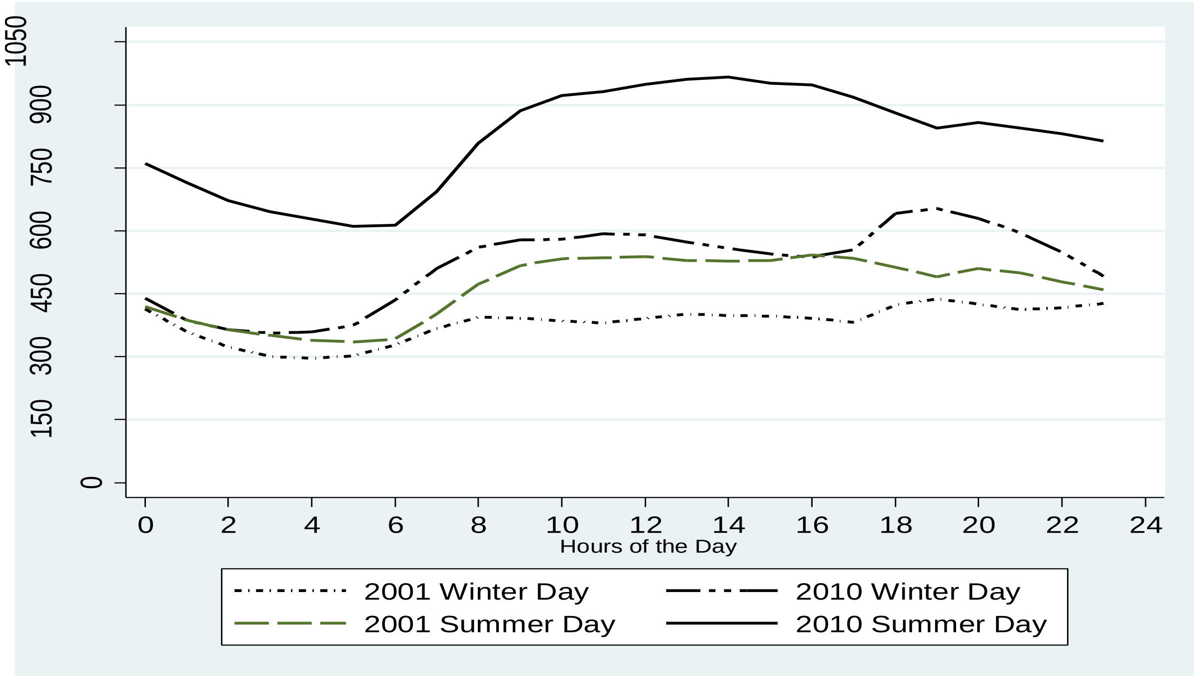
Power Generation Units / Years	2003	2004	2005	2006	2007	2009	2010
Dhekelia Steam Turbines - Capacity (MW)	360	360	360	360	360	360	360
Dhekelia Steam Turbines - Energy (MWh)	1,816,397	1,870,535	1,828,667	1,860,781	1,906,199	1,918,157	1,470,571
Dhekelia Steam Turbines - Load Factor (%)	57.6%	59.3%	58.0%	59.0%	60.4%	60.8%	46.6%
Dhekelia Internal CE - Capacity (MW)	0	0	0	0	0	50	100
Dhekelia Internal CE - Energy (MWh)	-	-	-	-	-	151,197	312,121
Dhekelia Internal CE - Load Factor (%)	-	-	-	-	-	34.5%	35.6%
Moni Steam Turbines - Capacity (MW)	180	180	180	180	180	180	180
Moni Steam Turbines - Energy (MWh)	376,135	437,579	497,348	446,393	405,227	388,498	249,913
Moni Steam Turbines - Load Factor (%)	23.9%	27.8%	31.5%	28.3%	25.7%	24.6%	15.8%
Moni Gas Turbines - Capacity (MW)	150	150	150	150	150	150	150
Moni Gas Turbines - Energy (MWh)	13,269	22,648	37,768	17,495	40,648	29,647	9,334
Moni Gas Turbines - Load Factor (%)	1.0%	1.7%	2.9%	1.3%	3.1%	2.3%	0.7%
Vasilakos Steam Turbines -Capacity (MW)	260	260	260	260	390	390	390
Vasilakos Steam Turbines - Energy (MWh)	1,615,001	1,617,879	1,735,560	2,159,537	2,426,217	2,231,516	2,283,763
Vasilakos Steam Turbines - Load Factor (%)	0.71	0.71	0.76	0.95	0.71	0.65	0.67
Vasilakos Gas Turbines -Capacity (MW)	38	38	38	38	38	38	38
Vasilakos Gas Turbines - Energy (MWh)	1,593	1,838	3,141	800	6,895	7,805	911
Vasilakos Gas Turbines - Load Factor (%)	0.48%	0.56%	0.96%	0.24%	2.10%	2.38%	0.28%

Source: Electricity Authority of Cyprus: https://www.eac.com.cy/EL/customerservice/Pages/default.aspx

Based on figure 2.2 below, demand for electricity follows both diurnal and seasonal changes in Cyprus. Consumers' electricity demand tends to increase more during peak load demand (summer days) than that during off-peak load (winter days) as shown in figure 2.2. That is to say, the quantity of electricity demanded by Cypriot consumers is higher when the air temperature increases in the island. Within these hours, the system approaches its available capacity during summer months of the year while only half of the generation capacity operates during the winter months of the year. This is due to the Mediterranean climate with hot and dry summers and mild winters.

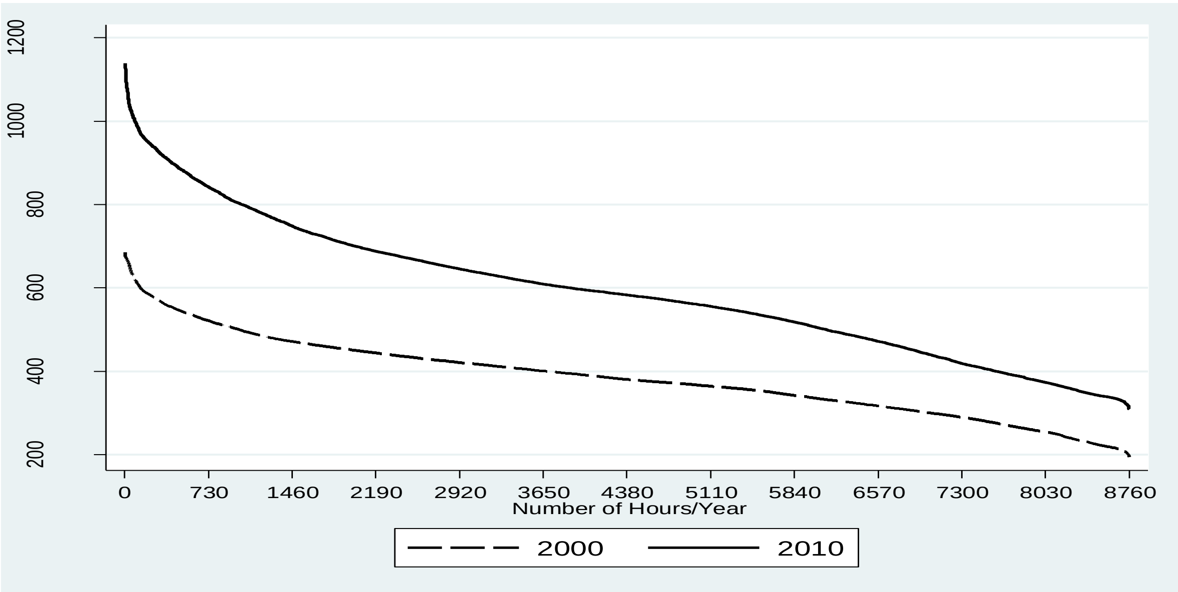
There is a massive influx of people into the island for short-term visits. The increase in temporary population during summer months of the year is translated into additional demand for electricity. Demand for peak capacity is also growing steadily in Cyprus as shown in figure 2.3 due to economic growth, temporary population growth, and air conditioner usage. The fixed pricing policy of the electric utility in Cyprus does not serve to mitigate these seasonal fluctuations in demand during the summer season. As with most electricity utilities in the world, the problem of capacity expansion and the under-utilization of the existing generation mix exist in Cyprus as well.

Figure 2.2 Typical Daily Load in Cyprus - Winter and Summer Days in 2000 and 2010



Source: Based on data available in web, supplied by Transmission System Operator, Republic of Cyprus/http://www.dsm.org.cy/nqcontent.cfm?a_id=1

Figure 2.3 Annual Load Duration Curves of Cyprus Island in 2000 and 2010



Source: Based on data available in web, supplied by Transmission System Operator, Republic of Cyprus/http://www.dsm.org.cy/nqcontent.cfm?a_id=1

2.3.3 Renewable Energy Sources in Cyprus

The factors pushing renewable energy higher up the agenda in Cyprus include the role of electricity in economic development, fuel costs and climate change. Indigenous primary energy sources for electricity generation on the island include wind, solar and biomass power (Rodoulis, 2010). Koroneos *et al.,* (2005) and Pilavachi *et al.,* (2009) study potential impacts of these on the Cypriot power sector. Both studies claim that introducing the indigenous energy sources will reduce the country's energy imports as well as contribute to the long term security of energy supply.

Meanwhile, the government of Cyprus sets various national targets to increase the overall use of renewables in order to fulfil its 2020 target set by the European Union, but the country still suffers from institutional and technical barriers for the development of renewable energy sources (Kassinis, 2009)[116]. Aside from the technical problems in wind power, both land planning problems and opposition from local communities are the main obstacles for wind power development in Cyprus (Gogakis, 2007)[117]. However, the Ministry of Commerce, Industry and Tourism (MCTI) of Cyprus argues strictly that wind power is "the most effective and economically efficient" source of renewable power to achieve national renewable targets in the country's electricity production (Gogakis, 2007; Rodoulis, 2010). Also, Cyprus Energy Regulatory Authority has already approved wind farm projects with significant capacities as of 2011 (CERA, 2011).

At present the grid connected solar PV is not competitive for sites with high irradiance and solar energy contributes a very small share of total electricity generation in Cyprus[118]. Depending on

[116]It is a climate change package of the European Commission (2008), suggesting 20% cut in emissions, 20% improvement in energy efficiency and 20% increase in renewables by 2020.
[117] Information is obtained from official portal of EU at: www.energy.eu/publications/a07.pdf
[118] The use of solar water heating system is widespread in Cyprus as 91% of dwellings have a solar system installed that makes SWHs biggest contributor to RES (Cyprus Energy Institute, 2012, p. 22). These small-scale SWH

future costs of conventional electricity generation, solar electricity generation might be competitive against conventional electricity generation. The technological development, discovery of new depletable energy sources such as natural gas around the island, and reduction of extraction costs of depleting the natural resource with high thermal efficiency (i.e. low economic costs and low emission levels) mean that it will take longer for solar PV to be competitive against conventional electricity generation. Because renewable energy sources currently enjoy subsidies, the user costs per unit of installed wind and/or PV capacity are lower than otherwise in Cyprus.

Wind is available throughout the day but usually produces more electric power during times of the day when demand for electricity and prices of electricity are lower. Wind power is economically feasible in high wind areas (wind speed exceeds 5m/s at 10 meter height) where earnings from wind power are sufficient to cover high capital costs. There are few locations suitable for wind farms as the wind power potential is limited across Cyprus (Pashardesand and Christofides, 1995; Jacovides *et al.,* 2002; Koroneos *et al.,* 2003; Pilavachi *et al.,* 2009). In this paper, we take into account wind resource profiles in the Paphos and Larnaca districts as future wind installations are assumed to be allocated in these districts of the country.

Currently, there are two wind farms in Cyprus; Orites wind farm (part of Paphos district) with nominal capacity of 82 MW and Ketonis wind farm (part of Larnaca district) with nominal capacity of 20 MW. As of January 2012, both these wind farms are connected to the Cypriot grid, and are operational and serving the Cypriot's electricity load. We utilized three-hourly wind speed data available for Paphos and Larnaca from January 2001 to December 2011. Available three–hourly wind speed data for the Paphos and Larnaca districts are provided for a height level of 9 meters and 2 meters, respectively. In this paper, wind power is estimated for wind speed at 90

investments are subsidised by the government in Cyprus - see:
http://www.mcit.gov.cy/mcit/mcit.nsf/All/BC386C0E0EFB879CC2256FC600311F46/$file/sxedio_EN_V30f+_draft.pdf?OpenElement)

meters height above the ground. Therefore, the *log-law rule* is applied in order to predict the wind speed at 90 meters height above the ground (Gualtieri and Secci, 2011)[119]. Countries with a high solar potential have advantages in solar power as does Cyprus having almost 300 sunny days in a year with a high solar irradiation level. Cyprus has solar energy abundance with an average global radiation level reaching about 5.4 kW/m^2 (Petrakis *et al.,* 1998). Unfortunately, solar electricity may not be in the generation mix in the near future because of low efficiency and high capital investment costs (Gogakis, 2007) that are a major deterrent to its penetration in an electricity market (Kahn, 1995; Beck and Martinot, 2004).

Solar photovoltaic electricity generation is not yet cost-competitive in most parts of the world and its applications represent only a small share of electricity capacity and electricity generation. Solar energy will be economically viable when electricity production from it is at least equal to savings from costs from conventional power generation. However, the use of solar heating has reached 554 kW$_{th}$ per 1,000 inhabitants as of 2009 in Cyprus that showed the country as being the world leader in solar heating on a per capita basis (Renewables Global Status Report, 2011). Unlike wind power, solar power is produced only during daylight hours and reaches its maximum in the middle of the day. In Cyprus, the solar irradiation received by a solar collector does not vary greatly (Kassinis, 2008; Pilavachi, 2009), a specific region for a candidate solar power site is not mentioned in this paper and the data for this analysis is obtained for the Larnaca district of the island.

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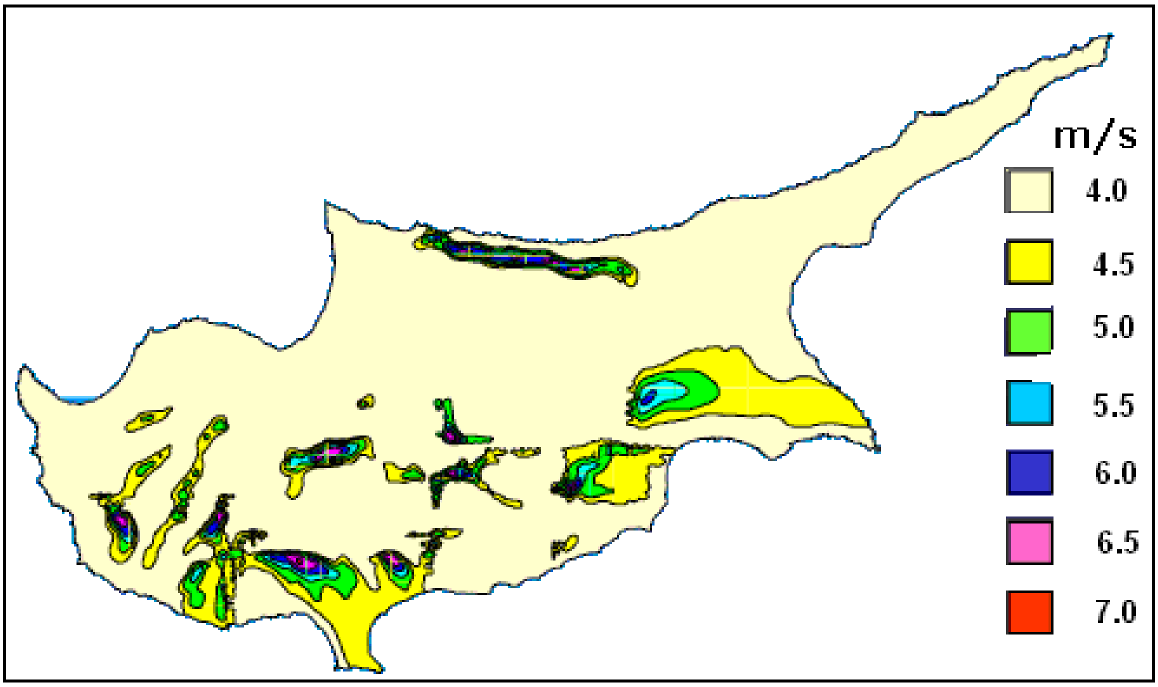
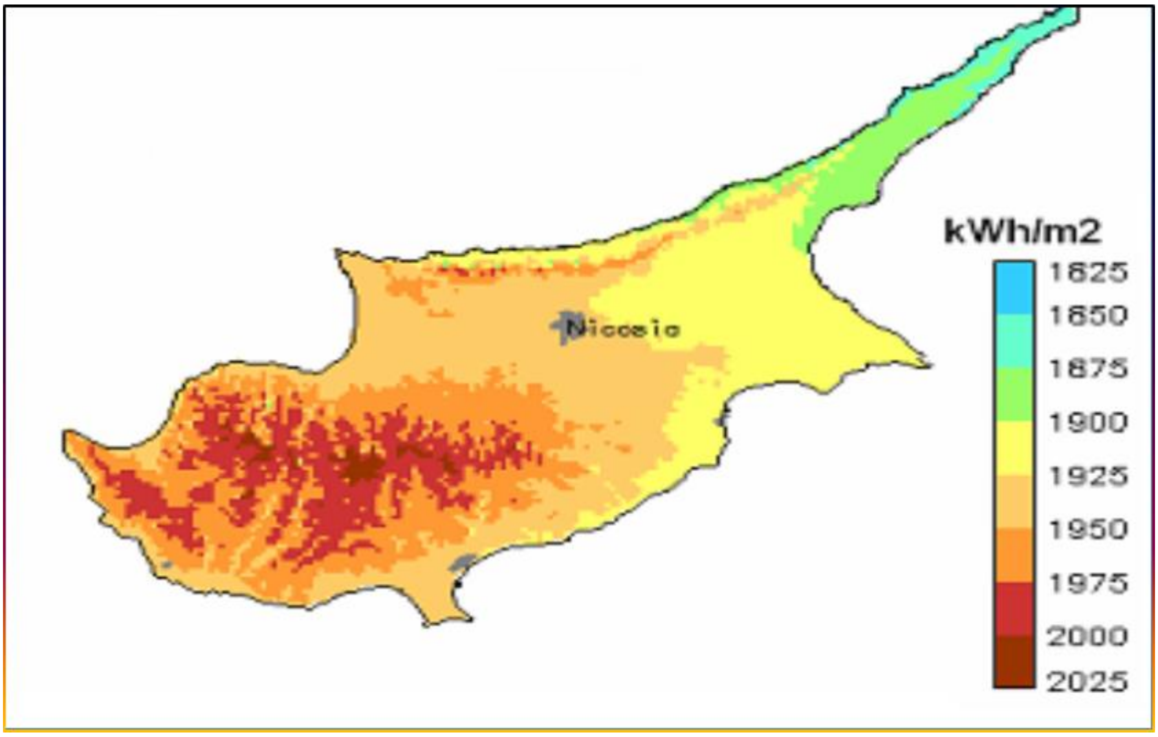
119 $\frac{u_x}{u_{90}} = \frac{\ln(x/z_0)}{\ln(90/z_0)}$, where z is roughly the length in meters. Roughness of length for village is less than the roughness of length in mountain areas. The roughness of length values for the two districts are tested with respect to the wind power curve from wind in order to arrive at meaningful load factors for wind power. In this paper, value of z is assumed to be 0.04 for Larnaca and 0.08 for Paphos.

Figure 2.4: Annual mean wind velocity in Cyprus



Source: Kassinis, 2009

Figure 2.5: Annual Solar Irradiation Level in Cyprus



Source: Kassinis, 2009

As previously stated both wind and solar generators are intermittent and non-dispatchable, it is also useful to estimate the *correlation coefficient* between the renewable electricity supplied to the grid and electricity demand by consumers.[120] Note that such statistical analysis is not sufficient to conclude whether or not the wind or solar integration yield the capacity generation adequacy. The generating capacity adequacy models must incorporate the reliability tests/standards and the uncertainties surrounding the evolution of supply and demand for capacity (Council of European Energy Regulators, 2014)[121].

Table 2.4 Correlation Coefficient between Wind, Solar and System Load

	Correlation Coefficient
Wind Profile (Paphos) and System Load	**0.02**
Wind Profile (Larnaca) and System Load	**0.12**
Solar Profile and System Load	**0.47**

Source: own calculations.

There is a very weak positive correlation between wind profile and load demand, so there is almost as much wind power during low demand hours as at the peaks. A very weak positive correlation between wind power and load demand has important economic implications such as (a) the capacity factor of wind power during the peak hours is not much greater than its annual average, (b) penetration of wind power in Cyprus will lower the operating load of the power plants running during off peak time - cheap to operate but expensive to build, (c) power system may need balancing reserves with wind integration that adds to the system back- up cost and (d) power plants running during low demand hours must be turned on and off quickly (flexible enough) so that they can cope with wind power variations while savings in costs can be maximized.

[120] Pearson product moment correlation coefficient shows the relationship (both strength and direction) between load demand and renewable power profile.
[121] See for example, Billinton, R., and Bai, G. (2004), "Generating capacity adequacy associated with wind energy," IEEE Transactions on Power Systems 19(3): 641–646.

From an environmental point of view, wind power supply displaces off-peak conventional power so it avoids emissions from low polluting plants in Cyprus. On the contrary, the coefficient estimates for a solar source seems more promising in economic and environmental points' of view for the island. Given that there exists an inverse relationship between capacity credit and power supply reliability; (a) solar with high capacity credit might contribute to the system reliability both in short-run and long-run and it might indirectly serve to achieve a degree of reserve capacity for the system, (b) penetration of solar power in Cyprus will reduce the operating load of the power plants running during peak time - when the marginal cost of supplying load is also high [122], (c) emission reductions from solar capacity will be significant because its availability at high demand hours when dirtier peak conventional operate in the system, and (d) solar power can act as a reserve for wind power in Cyprus when both wind and solar operate in the system.

2.4. Model

In this section of the paper, a model of a cost minimizing utility that is operating under specific demand, supply, reliability and regulatory constraints is presented. The model is deterministic so it does not capture the impacts of stochastic nature of renewables on the dispatching and scheduling of power plants. And, the dynamic operational constraints in unit commitment (UC) model are not presented as it requires extensive data on power plants including ramping units, start-up/ shut down times, minimum load requirements of power plants etc. Using the model, the nature of the benefits and costs of electricity generating from wind and solar sources into Cypriot (isolated power system) electric utility with different demand and supply conditions will be evaluated. Decision on capacity expansion planning requires consideration for both capital and

[122] In terms of clarification, off-peak plants with their lower marginal cost of production per MWh run continuously and when the demand for electricity increases during the peak hours, additional capital must be added to the off-peak generation capacity in order to meet the increased demand. Because of the low utilization levels of the peak generation plants, which operate only during peak hours will have higher marginal cost (sum of the capital costs plus operating expenses) of production per MWh. Hence, for the electricity system to be economically efficient, these peaking plants must be technologically less capital – intensive. This usually implies that the marginal running cost (primarily fuel cost) per MWh is high.

generation cost estimates (Turvey, 1963), so we employ both economic dispatch (ED) and capacity expansion (CE) problems simultaneously as we described each in section 2.2.1 of this chapter. For the sake of simplicity, the proposed model (a) is reduced into a single node in a way that all demand and supply is concentrated in a single node, (b) ignores Kirchhoff's law of transmission capacity, (c) neglects the transmission costs and how they differ with and without renewable power[123], (d) ignores renewables that are not grid-connected and (e) assumes that the operating system is flexible enough at all times to cope with the wind and solar variability.
The set of model constraints include demand and supply constraints, capacity limitations, system reliability constraints, renewable constraints, regulatory constraints and non-negativity constraints. Because of the high level of uncertainty associated in economic and technical parameters for power generation plants in the case of long-term decisions (Hobbs, 1995), these parameters are roughly approximated in this paper. These parameters play an important role in electricity generation and planning decisions because they measure the relative strength and weakness of a power plant against their counterparts (Meza, 2007). In order to reflect uncertainty of the parameters on the model outcomes, scenario analysis might be also employed to test the sensitivity of key input parameters used in the model.

Given the demand profile presented in figure 2.2 above, dispatching of power plants must follow the same pattern so that demand equals supply at all hours of the day and all seasons of the year. Different from thermal power supply, electricity generation from wind and solar sources differs

[123] Based on many EU area wind integration conducted by Holttinen *et al.,* (2009), wind energy transmission costs range from lowest 0$/kW to highest as $310/kW, in 2005 prices. Auer *et al.,* (2004) also investigates the impacts of different level of wind penetration and wind speed conditions on both additional system operation cost (capacity cost for system security and system balancing cost) and requirement on transmission and distribution network – grid extension cost - in EU (15) member states. They suggest that transmission and distribution upgrade with 20% wind share lie between € 2.5 and €3 per MWh of wind power, system balancing cost will lie between € 1.5 and €2 per MWh of wind power and finally the capacity reserve cost will lie between € 3 and €4 per MWh of wind power. Hence, the total will range between €7 and €9 for each MWh of wind produced if the wind power provides 20% of the total electricity consumption. Junginger (2003) covers both internal and external grid connection costs, and he argues that grid connection costs as a share of the total investment cost for off-shore wind farms are greater than for on-shore wind farms; internal and external grid connection cost range between 15% - 30% for off-shore wind farms, and 10%-15% for on-shore wind farms.

in different hours of the day due to daily weather changes (e.g. more wind during mid-nights and more sun during day time hours) as well differs across seasons (more wind during winter, more sun during summer months), as in Cyprus (Koroneos *et al.*, 2005). Since electricity generation from renewable sources also follows both diurnal and seasonal patterns, it is more realistic to analyse the impacts of wind and solar power by considering the changes in the load factor of a conventional power plant running at each time demand interval *h* (different for peak and off-peak hours) of year 't'.

In this chapter, demand for electricity is an exogenous variable; but the potential impacts of integrating short-term demand responses into long-term electricity expansion planning are considered in chapter 3. To properly illustrate wind and solar power availability the load in each hour time interval 'h' of the year should be considered. For this purpose, the two tables presented in appendices C and D summarize the number of hours when the load factors of wind and solar power coincide with the load demand (normalised relative to the average demand in the given year). Therefore, the optimization model is applied with a constraint of meeting the load demand at every sub-hour of the demand block. To do this, demand is divided into five load blocks including peak, high, intermediate, low, and baseload. Later on, each of these load demand blocks is sub-divided into five slices in order to combine the different load factor of renewable power sources and the load demand. Note that although there are numerous uncertainties in the operations as well as planning of power system such as wind speed and demand load which need to be identified and taken care of are not accounted in this research.

Total Economic Cost (in Euros - €): The total economic cost of expansion is composed of the sum of total fixed costs (investment and fixed operating and maintenance costs), total variable costs (variable operating and maintenance costs, variable fuel operating costs) and the variable cost of polluting from conventional electricity. The variable costs affect the power generation mix and fixed and variable costs together affect the power expansion mix. Therefore, total economic costs include both optimal stacking and optimal dispatching decisions within the model. In this section, a cost minimization model is applied that is equivalent to social welfare maximization with inelastic demand.

$$O_{11} = PV_{TFC} = \sum_{t}^{T}\sum_{c}^{C}(1+r)^{-t}\left[I_c\frac{(1+i)^n}{(1+i)^n-1}+F_c\right]\cdot K_{ct}+\sum_{t}^{T}\sum_{e}^{E}(1+r)^{-t}\cdot F_e\cdot K_{et} \tag{1}$$

where: PV_{TFC} is present value (discounted) value of total fixed costs, t is planning years (t,…,T) , i interest rate (%), r is discount rate , n is economic life time of proposed candidate power plant (years), c is index of candidate power plants, I_c is capital cost of candidate power plant (€/MW), e is index of exisiting power plants, K_{ct} and K_{et} are candidate capacity of candidate plants and existing plants, and F_c and F_e fixed operating and maintenance costs of candidate and existing power plant (€/MW), respectively.

Marginal running cost of a power generator composed of variable generation (fuel) cost and variable operating cost. These costs are known as economic dispatching costs from electricity generation. Variable operating costs and emissions from conventional power generator are functions of MWh electric power being produced. Moreover, the generation plants are heterogeneous so the operating costs and emissions from individual power plants for each MWh of electricity are not the same because of differences in their amount and type of fuel consumption.

In this chapter, it is assumed that as thermal plant ages; the amount of fuel it requires to produce a MWh of electricity will increase gradually. This factor, assumed to be 1%, is the same for all installed power plants. It is also argued that overall efficiency of the system increases once new plants become online (NPC Global Oil & Gas Study, 2007)[124]. Therefore, we implicitly assume that efficiency reduction due to physical depreciation dominates the efficiency gain due to new installations. The annual 1% increase in oil requirement for an additional kWh electricity generation of the existing and new power plants due to inefficiency starts immediately after the first year of the operation and included in the marginal cost parameter. Similarly, the variable O&M cost incurred by the plant is also subject to a 1% increase.

Together with the fuel and non-fuel operating costs, the variable costs of pollution created by the power plants are included in the total variable costs as it also affects the dispatching decisions for the power plants in the system (Green and Vasilakos, 2011; Saleiro *et al.*, 2007). What is more, these costs increase the relative attractiveness of the renewable power sources. These costs are financial costs and included in cost functions of power plants. The emission levels in quantitative units are also included as the total environmental degradation objective is measured in quantitative terms and required to assess the total environmental impacts from electricity generation. While deciding the minimum number of hours a plant which is relatively capital intensive with relatively lower marginal fuel cost, the utility runs the plant in question until when savings from lower fuel consuming plant offset higher capital cost of that plant. This is 'turning point' for the first generators on the load curve, starting from this turning point, utility runs the second relatively capital intensive with second lower fuel consuming plant, and so on. The variable cost of polluting power plants may increase in a country where emissions are priced in the power market - so comparison between fuel price and capital cost cannot be sufficient to determine right operational hours of plants. Although the carbon price fluctuates and has significantly fallen since the second half of 2008, we use a the new projection for the carbon

[124] Full working paper available at: http://www.npc.org/study_topic_papers/4-dtg-electricefficiency.pdf

price in 2020 of around €22/ tCO_2 – it is low in comparison to past projections as a result of recession (Commission of Climate Change, 2009, p.68).

$$O_{12} = PV_{TVC} = \sum_{t}^{T} (1+r)^{-t} \left\{ \begin{aligned} &\left[\sum_{h}^{H} \sum_{e}^{E} \left(f_{e,t} \cdot Fpf_{j,t} + VOM_{e,t} + CO_e \cdot Fpc_t \right) \cdot q_{e,ht} \cdot l_h \right] \\ &+ \left[\sum_{h}^{H} \sum_{c}^{C} \left(f_{c,t} \cdot Fpf_{j,t} + VOM_{c,t} + CO_c \cdot Fpc_t \right) \cdot q_{c,ht} \cdot l_h \right] \end{aligned} \right\} \quad (2)$$

where: t is planning years (t,…,T) , i interest rate (%), r is discount rate, h is time demand blocks in year , l_h duration of time interval h (number of hours in each time interval), e is set of existing power plants, c is set of candidate power plants, $f_{c,t}$ and $f_{e,t}$ is fuel consumption of candidate and existing power plants in year t (litre/kWh), respectively, $Fpf_{j,t}$ is price of j type fuel in year t (€/litre or €/10^3m^{3}N), $VOM_{e,t}$ and $VOM_{c,t}$ variable operating and maintenance costs of all power plant in year t (€/MWh), CO_e and CO_c is emission factor of all existing and candidate power plants (tonne/MWh), Fpc_t is CO_2 price year t (€/tonne CO_2), $q_{e,ht}$ and $q_{c,ht}$ is electricity produced from each existing and candidate plant in interval h of year t (MW), respectively.

It is possible to combine all the discounted fixed (O_{11}) variable fuel and operating and environmental damage costs (O_{12}) and express it in a single function as follows:

$$O_1 = O_{11} + O_{12} \quad (3)$$

We know that the generation displaced by and used to accommodate renewable output is not a proportional mix of the generation types in the system. Therefore, heterogeneity in emissions by fuel source in the system will have important implications for emissions savings from wind and/or solar integration. In order to estimate the emissions displaced by a new wind and/or solar PV installation, we need to identify the emission intensity of the marginal units displaced rather than system average emission rates. Total air pollutant emissions are defined as the sum of *CO_2,* emissions from conventional electricity generation. In this paper, emissions from power plants are assumed to be perfectly-mixing[125] and emission savings from wind and solar power are computed by replacing an average unit of conventional electricity generation and using average emission rates for each. Note that we did not integrate the abatement technology in our economic and environment modelling.

$$CO_2 \text{ emissions: } O_{21} = \sum_{t}^{T}\sum_{h}^{H}\sum_{e}^{E} CO_e \cdot \left(q_{e,ht} \cdot l_h\right) + \sum_{t}^{T}\sum_{h}^{H}\sum_{c}^{C} CO_c \cdot \left(q_{c,ht} \cdot l_h\right) \tag{4}$$

where: t is planning years (t,…,T), h is demand blocks in year t, l_h duration (hours) of each demand block h, t is time, e is set of existing power plants, c is set of candidate power plants, CO_e and CO_c are carbon emission factor of existing and candidate power plants (tonne/MWh), Fpc_t is CO_2 price year t (€/tonne CO_2), $q_{e,ht}$ is capacity supply from each existing plant in interval interval h of year t (MW) and $q_{c,ht}$ is the capacity supply from each candidate plant in interval h of year t (MW).

Model Constraints

Supply has to meet demand: Large amounts of electric power cannot be stored economically. Therefore, current and planned electricity generation has to meet demand for electricity at all times. The model presented in this paper also uses residual load with mix of renewables but without introducing the forced wind and solar capacity addition. Both wind and solar capacities are continuous decision variables in the model. Due to their reliance on weather, output from many of these renewable power sources is both intermittent and non-dispatchable. Integrating renewables into the power supply mix alters both the short-run optimum mix of power plants and long-term supply mix, but not in the same manner as adding a new conventional power plant

[125] Also see Callaway and Fowlie (2009) and Novan (2011).

as those plants are dispatchable (Lamont, 2008). With wind and/or solar power, these long term impacts depend strictly on load profile and the renewable load factors occurring at that particular point of the load profile (Lamont, 2008). In this paper, load factors for wind and solar power sources are taken into account in order to capture the intermittent nature of renewable power supply. In addition, scenario analysis without wind and solar power will allow us to quantify the backup capacity required by the system which allows us to capture the non-dispatchable nature of a renewable power supply (Morris *et al.,* 2010)[126].

$$\sum_{nre}^{NRE} q_{nre,ht} + \sum_{re}^{RE}\sum_{jh}^{JH}\left[LF^{m}_{we,jht} \cdot K^{m}_{we,t}\right] + \sum_{nrc}^{NRC} q_{nrc,ht} + \sum_{rwc}^{RWC}\sum_{jh}^{JH}\left[LF^{m}_{wc,ht} \cdot K^{m}_{wc,t}\right] + \sum_{rws}^{RWS}\sum_{jh}^{JH}\left[LF_{sc,jht} \cdot K_{sc,t}\right] = D_{ht} \qquad \forall_{ht} \qquad (5)$$

where: h is time demand blocks in year t, j is sub-hour in each demand block, nre is set of non-renewable generators in year t, $q_{nre,ht}$ is the MW capacity supplied from them in each demand block h in year t , nrc is set of non-renewable candidate technologies that are installed in year t and $q_{nre,ht}$ is the MW capacity supplied from them in each demand block h in year t, $LF^{m}_{we,jht}$ is load factor of existing wind power in region m at j sub hour of in each demand block h of the year t, $LF^{m}_{wc,jht}$ is load factor of candidate wind power in region m at j sub hour of time in each demand block h of the year t, $LF_{sc,jht}$ is load factor of candidate solar power at j sub hour of each demand block h of the year t (%), $K^{m}_{we,t}$ and $K^{m}_{wc,t}$ is the existing and candidate MW wind capacity in region m in year t, respectively. $K_{sc,t}$ is the MW candidate wind solar capacity that are

126 In order to assess the economic value of electric power produced from renewables; we will compare "with" and "without" wind and solar power mix scenario. By this way, we are able to determine dispatchable back-up conventional generating capacity to renewable power assuming that required back-up capacity is MW to MW of mix of renewables (Morris *et al.,* 2010 pg. 6). According to MW - MW back up capacity equalization, interconnection within wind turbines (as well as solar panels) is ignored, so required back up capacity is overstated with respect to increase in shares of renewables.

added into the system in year t (MW), and D_{ht} is MW gross demand for capacity in time interval h in year t.

System reliability: Operating reserves (φ) is required for maintaining the system reliability that is represented as fraction of peak demand. These reserves should be in the system as standby due to sudden fluctuations in demand for and/or supply of electricity.

$$\sum_{nre}^{NRE}\left(q_{nre,ht}+qs_{nre,ht}\right)+\sum_{nrc}^{NRC}\left(q_{nrc,ht}+qs_{nrc,ht}\right)\geq D_{ht}^{p}\cdot\left(1+\varphi_{t}\right) \qquad \forall_{ht} \tag{6}$$

where: nre is set of non-renewable generators in year t, $q_{nre,ht}$ is the capacity supplied from them in each demand block h in year t, qs_{nre} is reserves from existing conventional power plants in year t (MW), nrc is set of non-renewable candidate technologies that are installed in year t, $q_{nrc,ht}$ is the capacity supplied from candidate conventional plants at demand block h in year t (MW), $qs_{nrc.ht}$ is the capacity supplied from them in each demand block h in year t (MW), D_{ht}^{p} is peak demand for capacity in time interval h in year t, φ_t is reserve margin required by system planning at peak load in year t (%)

Electricity generated by conventional units: Amount of electric power generation from conventional power plants is limited by the availability factor (a) of each power plant.

$$q_{nre,ht}+qs_{nre,ht}\leq a_{nre,ht}\cdot K_{nre,t} \qquad \forall_{ht} \tag{7}$$

$$q_{nrc,ht}+qs_{nrc,ht}\leq a_{nrc,ht}\cdot K_{nrc,t} \qquad \forall_{ht} \tag{8}$$

where: nre is set of existing non-renewable generators and $q_{nre,ht}$ is the capacity supplied from them in each demand block h in year t, $a_{nre,ht}$ is availability factor of existing conventional power plants at time interval h of the year t (%) that is assumed to be the same throughout the year, $K_{nre,t}$ is installed exisiting conventional capacity of plants at time interval h of the year t (%) that is assumed to be the same throughout the year, nrc is set of non-renewable candidate technologies that are installed in year t and $q_{nre,ht}$ is the capacity supplied from installed candidate plants in each demand block l in year t, $a_{nrc,ht}$ is availability factor of existing conventional power plants at time interval h of the year t (%) that is assumed to be the same throughout the year and $K_{nre,t}$ is installed conventional capacity from candidate plants at time interval h of the year t (%).

Electricity generated from renewable power units: Unlike any conventional power plant, the amount of electric power that can be produced from renewable sources is determined by the load factor. In most cases, a renewable source of power supply has legal protection (grid access priority) to ensure it can sell its output.

$$q^{m}_{we,ht} \leq \sum_{jh}^{Jh} \left[LF^{m}_{we,jht} \cdot K^{m}_{we,t} \right] \qquad \forall_{we,ht} \qquad (9)$$

$$q^{m}_{wc,ht} \leq \sum_{jh}^{Jh} \left[LF^{m}_{wc,jht} \cdot K^{m}_{wc,t} \right] \qquad \forall_{wc,ht} \qquad (10)$$

$$q_{sc,ht} \leq \sum_{jh}^{Jh} \left[LF_{sc,jht} \cdot K_{sc,t} \right] \qquad \forall_{sc,ht} \qquad (11)$$

where: $q^{m}_{we,ht}$ and $q^{m}_{wc,ht}$ is the existing and candidate installed wind power in region m in interval h of the year t (%), respectively, $LF^{m}_{we,jht}$ is load factor of existing wind power in region m at j sub hour of in interval h of the year t (%), $LF^{m}_{wc,jht}$ is load factor of candidate wind power in region m at j sub hour of time in interval h of the year t (%), $q_{sc,ht}$ is the candidate solar power in interval h of the year t , $LF_{sc,jht}$ is load factor of candidate solar power at j sub hour of time in interval h of the year t (%), $K^{m}_{we,t}$ and $K^{m}_{wc,t}$ is the existing and candidate wind capacity in region m in year t, respectively. $K_{sc,t}$ is the candidate wind solar capacity in year t (MW).

A final note on the load data is that by imposing the equality constraint in the model for wind and solar power, the residual demand is implicitly derived within the model. When both wind and solar power is integrated into the electric utility's grid, the change in the load demand or the residual demand is estimated by the following equation:

$$D^{*}_{ht} = D^{g}_{ht} - \sum_{jh}^{JH}\left[LF^{m}_{we,jht} \cdot K^{m}_{we,t}\right] - \sum_{jh}^{JH}\left[LF^{m}_{wc,jht} \cdot K^{m}_{wc,t}\right] - \sum_{jh}^{JH}\left[LF_{sc,jht} \cdot K_{sc,t}\right] \quad \forall_{ht} \qquad (12)$$

where: D^{*}_{ht} is the residual amount of power that must be supplied from the non-renewables at each demand block, D^{g}_{ht} is demand gross of wind capacity at block 'h' in MW. $LF^{m}_{we,jht}$ is load factor of existing wind power in region m at j sub hour of in interval h of the year t (%), $LF^{m}_{wc,jht}$ is load factor of candidate wind power in region m at j sub hour of time in interval h of the year t (%), $LF_{sc,jht}$ is load factor of candidate solar power in region at j sub hour of time in interval h of the year t (%), $K^{m}_{we,t}$ and $K^{m}_{wc,t}$ is the existing and candidate wind capacity in region m in year t, respectively. $K_{sc,t}$ is the candidate wind solar capacity that are added into the system in year t (MW).

For various amounts of wind and solar power capacities (scenarios), the changes in the load factors at different demand blocks can be computed.

Renewable power targets in electricity generation: The amount of electricity generation from mix of renewable sources represented as a proportion of total demand for electricity is set as the national target. Being a full member of the European Union, the use of renewable sources will increase in the country's electricity generation programme in order to comply with environmental measures set by the EU. The national renewable targets (ω) vary across EU member state that reflects the different availability of renewable resources in each member state.

$$\frac{\sum_{jh}^{JH}\left[q_{we,ht}^{m} + q_{wc,ht}^{m} + q_{sc,ht}\right]}{\sum_{h}^{H} D_{ht}} \geq \omega_t \qquad \forall_{t\geq 1} \qquad (13)$$

where: $q_{we,ht}^{m}$ and $q_{wc,ht}^{m}$ is the existing and candidate installed wind power in region m in interval h of the year t, respectively, $q_{sc,ht}$ is the candidate solar power in interval h of the year t, ω_t is share of renewables in total demand for electricity in year t (%) and D_{ht} is demand for electric power in time interval h in year t (MW)

Total capacity in the existing system: Some capacity in the system is expected to be decommissioned in Cyprus (Poullikkas and Kellas, 2004). As a consequence, the available capacity from existing power plants at time "t" is obtained by subtracting the power plants that are planned to be decommissioned in the same year.

$$K_{et} \leq K_{e,t-1} - K_{d,t} \qquad \forall_t \qquad (14)$$

where: K_{et} and $K_{e,t-1}$ installed power of existing power plants in year t (MW) and t-1, respectively, and K_{dt} is decommissioned capacity from existing power plant in year t (MW).

Installed capacity of candidate units: This is necessary in order to avoid unrealistic solutions, and so new capacity addition must be obtained from a pre-assigned set of candidate capacities (Mazer, 2007, p.143). This does not apply for wind or solar power because a small scale wind and/or solar capacity addition is realistic and possible. For wind and solar power, the future maximum amounts of wind and solar power that can be installed into the system are defined within the constraints of the proposed model.

$$K_{nrc,t} = \sum num_{nrc} \cdot MW_{nrc} \qquad \forall_{nrc,t} \tag{15}$$

$$K_{wc,t} \leq MW_w \qquad \forall_{wc,t} \tag{16}$$

$$K_{sc,t} \leq MW_s \qquad \forall_{sc,t} \tag{17}$$

where: K_{nrct} thermal capacity additions in year t (MW), num_{nrc} is number of different capacities assigned to candidate conventional plants, MW_{nrc} is pre-assigned capacities for candidate thermal power plants (MW), $K_{wc,t}$ and $K_{sc,t}$ wind and solar capacity additions in year t (MW), respectively and MW_w and MW_s is pre-assigned total wind power and solar power potential (MW).

Non – negativity constraints

$$q_{e,ht} \geq 0 \qquad \forall_{e,ht} \tag{18}$$

$$q_{c,ht} \geq 0 \qquad \forall_{c,ht} \tag{19}$$

$$K_{c,t} \geq 0 \qquad \forall_{c,t} \qquad (20)$$

where $q_{c,ht}$ is conventional electricity produced from each candidate plant in interval h of year t (MW) and $q_{e,ht}$ is electricity produced from each existing plant in interval h of year t (MW) and $K_{c,t}$ is capacity of candidate conventional and renewable (wind and/or solar) power plant (MW).

A final consideration is the selection of an algorithm to solve the multi-objective problem. It is possible to reduce these two opposing objective functions into a composite (or single) objective function by a weighting approach or ε -constraint approach (Zitzler *et al.,* 1993). In the w*eighting* method, a weighted sum of objective functions are optimized by assigning weight to each function while in the ε *-constraint* method; one objective function is optimized while other objective function (s) is included in the constraint sets. Using the ε *-constraint* method*,* the trade-off between the objectives can be easily computed as well as *Pareto optimal – non-dominated* solutions for the model can be obtained (Mavrotas, 2006). Note that a weighting approach can be used only when the decision maker has prior knowledge on each of the criteria. If it is not known, the ε *-constraint method* would be appropriate as different allowable emission limits can be set to determine the least-cost solutions as well as possible trade-off between each optimization problem already defined above. Since the weights are unknown in our analysis, the use of the ε-*constraint* method would be appropriate.

2.5. Empirical Results

The cost minimization model presented here is the combined economic dispatch and capacity expansion problem of optimization with a mix of wind and solar power applications. The model is applied empirically for the Cypriot electricity grid from 2011 to 2020 and analyses are carried out at the price of fuel oil of 200 Euros/tonne (for existing plants), the price of natural gas of 250

Euros/m^3N (for candidate plants) and the total level of allowable emissions of 30,000 thousands of tons during the planning period (Department of Environment Ministry of Agriculture, Natural Resources and Environment, Cyprus, May 2011)[127]. The discount rate chosen in the empirical estimates for Cyprus is 10%. We also present sensitivity analysis relating to the choice of discount rate at varying rates[128].

If an electric utility wants to keep operations at the lowest cost with the given demand for electric power, the optimal investments of the power generation units is more in favour of peak thermal and wind power. As expected, there will be no installations of new solar power in the near future due to the high capital costs associated with solar power investments. In order to achieve the minimum cost over the planning period in Cyprus, the optimal timing and size of expansion investments will be as follows:

Table 2.5 Cumulative Optimal Time and Size for an Expansion by Plant Type (MW)

	2014	2015	2016	2017	2018	2019	2020
Baseload	-	-	74	129	300	300	300
Intermediate	-	-	-	-	-	13	300
Peak	-	-	-	-	-	46	46
Wind	-	5	11	40	47	54	200
Solar	-	-	-	-	-	-	-

Source: own estimates.

The net benefits of wind and/or solar power will be fuel savings from reduced use of thermal plants less the added costs of operating the thermal system to supply the remaining power

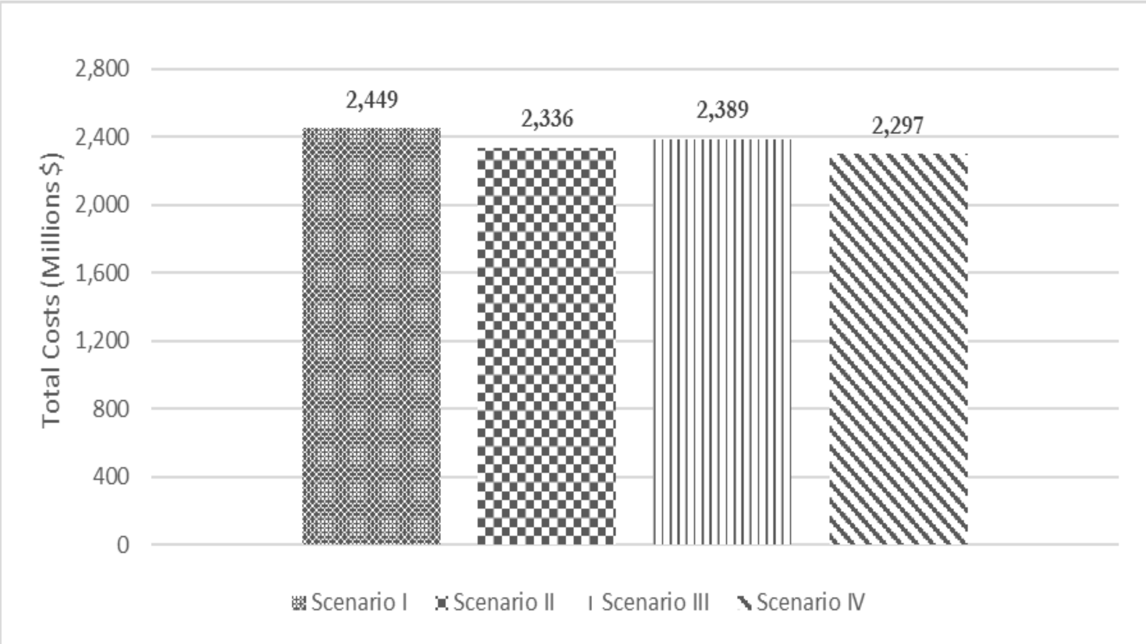
[127]See:http://www.moa.gov.cy/moa/environment/environment.nsf/724D802BD314A271C22579410036A4A3/$file/PROJ%202011.pdf Maroulis, (2014), "Assessment of climate change policies in the context of the European Semester Country Report: Cyprus", Available at: http://ec.europa.eu/clima/policies/g-gas/progress/docs/cy_2014_en.pdf and Climate Action of the EU at http://ec.europa.eu/clima/policies/ets/cap/auctioning/derogation_faq_en.htm

[128] The social discount rate employed in the appraising public projects suggest that the rate of discount is equal to the rate of pure utility discount (typically 1-3%) plus [the elasticity of marginal utility (typically 1-2) multiplied by the long run average consumption growth rate that could be anything for Cyprus especially given the recent gyrations. Therefore, we used 10% discount rate in our analysis.

required that is not met by the renewable source. Based on the numerical results indicated above, there will be added costs in the form of increased average fuel costs per unit of thermal generation because the optimal mix of plants with wind will require more peaking plants (single cycle gas turbine in our case) and fewer baseload plants (combined cycle in our case). However, the capital costs of these peaking thermal plants are less so there will be an offsetting benefit of lower capital costs than what would have been optimal without wind and/or solar power. Using fuel and natural gas price assumptions above, the changes in the total cost (variable generation and fixed costs) with and without (assuming to be reference case) wind power are presented below.

The existing power supply mix does not include that of solar power, so scheduling of the power plants to meet the demand for electricity at the lowest cost includes a mixture of thermal and wind power sources only. Given the total estimated cost of power supply in scenario B, the optimal allocation of generation mix from both existing and new power plants at each demand block is presented below. In order to show the impact of different wind penetrations on the power system and economic costs, we estimate the costs under scenarios with no wind and solar capacity (Scenario I), high wind as in Table 2.5 (Scenario II), low wind with half the level shown in Table 2.5 (Scenario III), and equal wind – high wind amd solar capacity penetration (Scenario IV). Then, it is revealed that wind power installations will reduce the total costs of the system as they penetrate the system. This is due to the fact that wind replaces the power from conventional plants and saves variable operating and variable fuel costs from these plants. In any of the scenarios, no solar capacity will yet be in the system.

Figure 2.6 Total Cost of Power Supply (NPV values at 10% discount rate, Heavy Fuel Oil Price at € 50/barrel, natural gas price at € 450 $/10^3 m^3 N$, carbon price at €22/ tCO_2), millions of €



Source: Own calculations.

However, correlation coefficient estimates between the renewable resource profile and system load tells us that it would be a better system from an engineering point of view to have both wind and solar power than wind alone. This is because the effect of introducing solar power into the mix may offset higher reserves or costs of wind power. This is a reasonable statement as solar power is more available in summer time when the demand for electricity reaches its peak level in Cyprus. In order to illustrate the scenario with a mix of wind and solar power, we include an additional constraint in our model so that we force solar power to be in the system[129]. This will allow us to show the impacts of wind and solar power penetration on the operating regime of the conventional system. The results reveal that there will be substantial reduction in the system cost if both wind and solar power penetrates the system than wind power alone. This is due to fact that solar power displaces higher variable cost plants than wind power.

[129] This constraint implies that solar power is committed for the future power mix and capital costs will be incurred by the system.

When both wind and solar power capacities operate in the system, both optimal power generation and expansion units will be different from that of the wind alone case as presented in Table 2.5. The difference arises due to the different adjustment factors of the solar power alongside with wind power. We expect that solar power will save capital costs from peaking plants, as less peaking thermal will be needed with solar power. Therefore, solar power will generate earnings from the capacity credit.

The factors such as high fuel (natural gas) costs and high transportation costs causing further increases in domestic fuel prices may increase the attractiveness of electricity generation from renewables. A new optimal level of thermal plant mix (optimal stacking) in electricity generation will also change depending on the relative changes between fuel oil and natural gas price. Therefore, comparative results with different fuel input assumptions are presented to show their potential impacts on optimal wind and/ solar power deployment.

Table 2.6 Impacts of Changing Fue and Natural Gas Prices on the Total Cost of Power Supply with Different Renewable Penetration, values in millions of €

	HFO: €50 / Barrel NG: €450/$10^3 m^3 N$	HFO: €55/Barrel NG: €475/$10^3 m^3 N$	Heavy Fuel Oil: €60/Barrel NG:€500/$10^3 m^3 N$	Heavy Fuel Oil: €65 /Barrel NG:€525/$10^3 m^3 N$	HFO: €70 / Barrel NG:€550/$10^3 m^3 N$
Scenario I	2,449	2,647	2,846	3,074	3,362
Scenario II	2,336	2,471	2,608	2,773	2,970
Scenario III	2,389	2,344	2,476	2,561	2,653
Scenario IV	2,297	2,315	2,407	2,478	2,542

Source: Own Estimates

The costs from an optimal mix of generating plants is calculated at a price of fuel oil from 50 €/barrel to 70/barrel, while the price of natural gas from € 450 $/10^3 m^3 N$ to € 550 $/10^3 m^3 N$ and the total level of allowable emissions remain the same at 30,000 thousand tonnes during the planning period in question. In order to show the impact of different wind penetrations on the power system and economic costs, we again estimate the costs under scenarios with no wind and solar capacity (Scenario I), high wind (Scenario II), low wind with half the level (Scenario III), and equal wind – high wind amd solar capacity penetration (Scenario IV). The resulting costs are shown table 2.6 above. Based on table 2.6 presented above, we find that when the prices of conventional plants running with heavy fuel oil and natural gas increases, the additional savings from integrating renewables will also increases. This is because wind and solar sources will reduce fuel payments for the energy displaced from them.

Moreover, estimation of the trade-off between costs and emissions, as shown in Figure 2.5, is important for policy makers as it allows policy makers to see the additional costs resulting from a lower level of emissions, and vice-versa. The lines in the Figure are derived by taking the level of emissions as part of the constraint set, since the value of the weight on each objective function may not be known. Based on the characteristics of the power system with its economic and emission parameters, we show that wind power is not an expensive source of electric energy for Cyprus with a significant amount of negative environmental externalities avoided for a small increase in costs. This type of analysis is for example useful when determining the effectiveness of the renewables targets in reducing the emissions. To put it differently, whether the use of renewables is effective or not depends on the trade-off between the high cost of electricity from renewables and the benefits they deliver in the form of abating local pollution and mitigating greenhouse gas emissions.

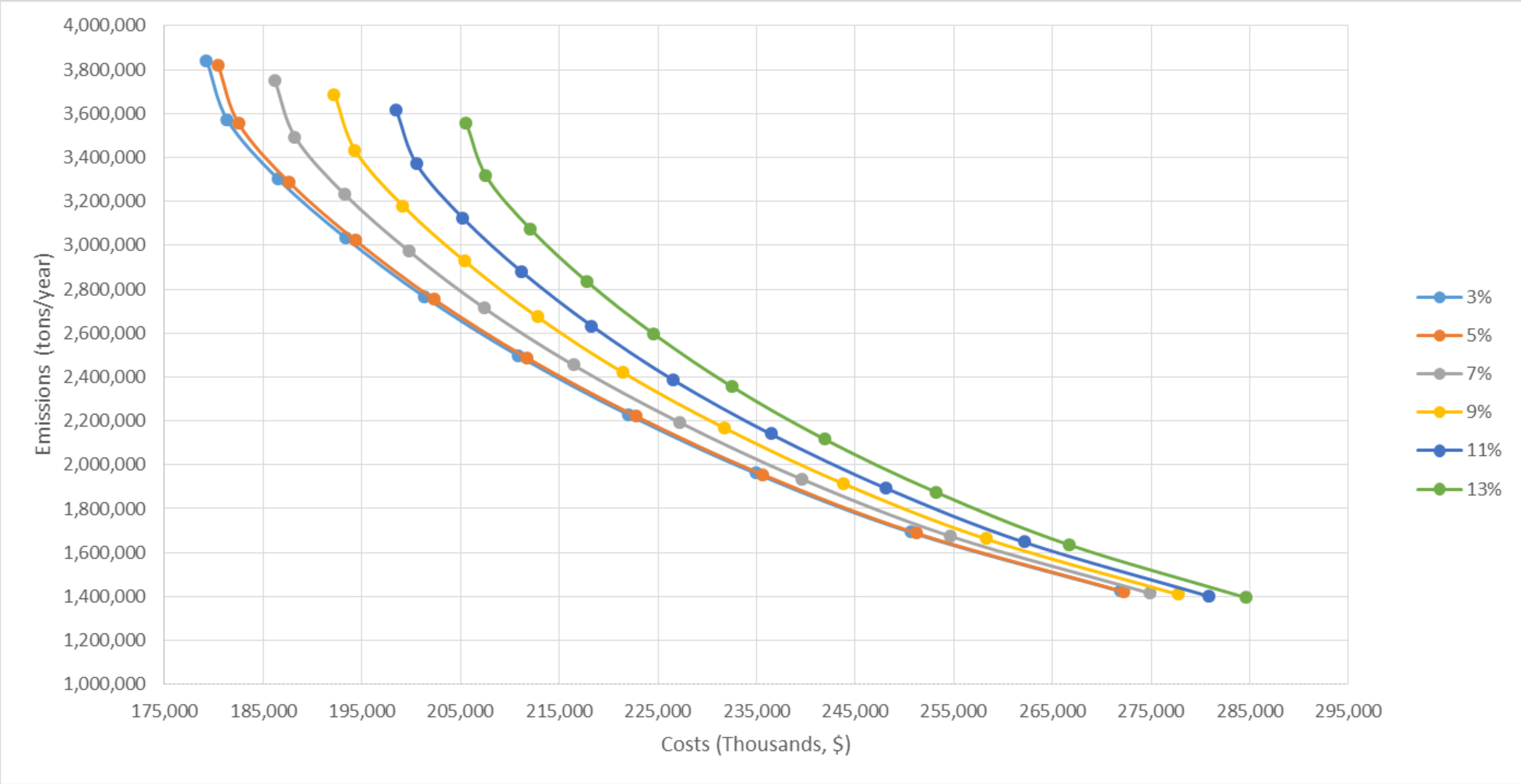
Conventional power generation is increasingly being penalized with emission costs and this ultimately increases the cost of electricity generation. Furthermore, an optimal level of renewable power penetration is expected to increase with the cost of emissions. All these impacts depend on the power plant mix such that more renewable penetration exists in a coal power oriented mix than in a mix dominated by oil or natural gas. This is due to fact that coal fired plants emit more carbon than oil fired or natural gas plants. Hence, the impact will be smaller for Cyprus considering its current and future power generation mix.

2.6. Conclusions and Policy Recommendations

The Electricity Authority of Cyprus currently imports all of the fuel oil needed to generate electricity and the percentage of imported fuel for power generation still remains very high. This heavy reliance on imported fuel oil for electricity generation, an increase in energy consumption per capita and the green regulations of the EU are the main motivating forces behind the push of investments in energy efficiency programs and renewables in Cyprus - as a member of EU.

Looking at the future of the electricity generation mix in Cyprus, accommodation of wind power on the national grid will become an increasingly important issue as wind is the largest new source of installed capacity in Cyprus. As in many countries, renewable sources of power supply have also grid access priority in Cyprus. Due to lower wind potential in the island, investors receive a fixed feed-in for twenty years and high subsidies from the special fund established for the purpose of supporting renewable energy sources in Cyprus. Because of higher upfront capital costs, the amount of subsidy for each MWh of electricity generated from solar power is higher than the level given to wind power investors.

Figure 2.6 Trade-off between Emissions and Costs at Varying Renewable Energy Targets



The most challenging issue is formulation and implementation of the right policy for promoting these renewables at the right time for the right use of potential renewables. In the future, the effect of introducing solar and wind power into thermal electricity generation will work better than wind power alone. Therefore, wind power investments should be postponed until the unit cost of electricity generation from solar power can also show savings. We expect the gap between the unit cost of solar electricity and the unit cost of fuel to converge in the near future due to technological improvement, economies of scale and strong renewable support policy[130]. Wind power installations will continue given that it reduces the total system costs partially due to regulatory constraints in the system such as renewable power share and emissions limits and also reduction in capital cost installations.

Not only does the fuel consumption of thermal plants, but future oil and natural gas prices also play a key role in renewable power deployment in any country. Thus, the expected benefits of wind and solar power generation for the electric utility as well as the economy of Cyprus depend on one's view of future oil and natural gas prices as well as the ratio of the price of crude oil compared to the price of natural gas. Natural gas is now competing with "cheap but dirty" coal and "expensive but clean" renewable investments and it seems this will continue in the future due to a reduction in the extraction costs of gas (Burtraw *et al.,* 2012).

We run the sensitivity for the various fuel oil and natural gas prices in Cyprus and we find that when the prices of conventional energy running with heavy fuel oil and natural gas increases, the marginal savings from integrating renewables increases. In fact, the increase in prices of conventional fuel sources should bring these investment in the system earlier. These conclusions are valid on the assumption that consumers are not price-responsive, however.

[130] See for example, Barbosa *et al.,* (2012).

Exporting natural gas has an economic opportunity cost for Cyprus as it can be used in the domestic market for electricity production. Although it looks as if the domestic use of "cheap and clean" natural gas resources is viable from an economy and environmental point of view, careful evaluation of options for domestic use of natural gas versus exporting the natural gas is inevitable. Of course, the policy maker cannot ignore the potential of renewable energy sources. Comparing the value of fuel and carbon savings foregone from shifting toward natural gas plants would help policy makers to decide what to do with the natural gas and investments in renewables.

Finally, we need to compare the value of fuel and carbon savings foregone from investing the same amount of capital in alternative power generation plant such as a "fuel efficient and clean" CCT[131,132] because every dollar spent on reliable and relatively low cost technology such as CCT[133] may yield higher economic and environmental benefits than spending capital on on-grid. In this way, we will answer the question of whether wind power is really cost-effective for the electric utility and economy of Cyprus and a greener option for the environment.

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131 Similar to what we suggest, Dale *et al.* (2004) analyze the impact of large-scale wind turbine installations in the UK in terms of the cost (price) that electricity consumers pay. They take into account generation investment costs, fuel cost and network cost including connection and infrastructure costs associated with wind investments. In their research, two scenarios are considered; (a) thermal generation (coal and gas turbines) dominates the power supply in 2020 and (b) together with conventional power, wind source of power supply (mix of on –shore and off-shore) represents 20% of total electricity production. They estimate that electricity consumers pay additional costs of just more than 0.3p/kWh in current prices, and pay less than 0.1p/kWh if wind has no displacement value. Based on their empirical result, they conclude that there is no reason for not supplying the country's electricity demand by wind.

132 With the research and development in the power generation industry, capital costs of conventional generators have been falling including the CCGT technology. In addition to this, capital costs of these generators are still much lower than wind and solar and also provide high reliability in power system as they are dispatchable (US Energy Administration, 2013). Last but not least, the fuel efficiency of CCGTs increased from 30-40% to 50%-60% in the last two decades and is even now improving over time (Asian Pacific Energy Research Centre, APERC, p.27 2010). Higher fuel efficiency in turn means lower fuel consumption and lower emissions per kWh of energy produced.

133 The advantages of CCGT in an island economy, Cyprus, are analysed by Poullikkas, A., (2004), "Parametric study for the penetration of combined cycle technologies into Cyprus power system), *Applied Thermal Engineering*, 24 (11–12): 1697–1707.

Appendix

List of Symbols – Glossary

t	planning years (t,…,T)
h	time demand blocks in year
l_h	duration of time interval h (number of hours in each time interval)
l_{jh}	duration of sub hour j in time interval h
z	index of all power plants
e	index of existing power plants
$nr(e)$	index of existing non-renewable power plants where
$w(e)$	index of existing wind power plants where
c	index of candidate power plants
$nr(c)$	index of candidate non-renewable power plants where
	cbl = candidate baseload capacity, cbl = candidate intermediate capacity, cpl = candidate peaking load capacity
$w(c)$	index of candidate wind power plants where
$s(c)$	index of candidate solar power plants where
D_{ht}	demand for electric power in time interval h in year t (MW)
D_{ht}^{*}	residual demand for electric power in time interval h in year t (MW)
D_{ht}^{p}	peak demand for capacity in time interval h in year t
φ_t	reserve margin required by system planning at peak load in year t (%)
qs_{nre}	reserves from existing conventional power plants in year t (MW)
qs_{nrc}	reserves from candidate conventional power plants in year t (MW)
K_{et}	installed power of existing power plants in year t (MW)
K_{dt}	decommissioned capacity from existing power plant in year t (MW)
num_{nrc}	number of different capacities assigned to candidate conventional plants
MW_{nrc}	pre-assigned capacities for candidate conventional power plants (MW)
MW_w	pre-assigned wind power potential in region (MW)
MW_s	pre-assigned solar power potential in region (MW)

K_{ct} capacity of candidate power plant(MW)

n economic life time of candidate power plant (years)

I_c capital cost of candidate power plant in year t (€/MW)

F_{ct} fixed operating and maintenance costs of candidate power plant in year t (€/MW)

$K_{cnr,t}$ thermal capacity additions in year t (MW)

F_{et} fixed operating and maintenance costs of candidate power plant in year t (€/MW)

VOM_{ct} variable operating and maintenance costs of candidate power plant in year t (€/MWh)

VOM_{et} variable operating and maintenance costs of existing power plant in year t (€/MWh)

f_{ct} fuel consumption of candidate power plants in year t (m^3N/MWh)

f_{et} fuel consumption of existing power plants in year t (tonne/MWh or m^3N/MWh)

$q_{c,ht}$ conventional electricity produced from each candidate plant in interval h of year t (MW)

$q_{e,ht}$ electricity produced from each existing plant in interval h of year t (MW)

Fpf_{ft} price of f type fuel in year t (€/tonne or €/$10^3 m^3N$)

$a_{nre,ht}$ availability factor of existing conventional power plants at time interval h of the year t (%)

$a_{nrc,ht}$ availability factor of existing conventional power plants at time interval h of the year t (%)

$LF^{m}_{we,jht}$ load factor of existing wind power in region m at j sub hour of time in interval h of the year t (%)

$LF^{m}_{wc,jht}$ load factor of candidate wind power in region m at j sub hour of time in interval h of the year t (%)

$LF_{sc,jht}$ load factor of candidate solar power at j sub hour of time in interval h of the year t (%)

ω_t share of renewables in total demand for electricity in year t (%)

CO_c CO_2 emission factor of all power plants (tonne/MWh)

CO_e CO_2 emission factor of all power plants (tonne/MWh)

Fpc_t CO_2 price year t (€/tonne CO_2)

r real discount rate in year t (%) and

i interest rate (%)

Appendices

Appendix A: Economic Parameters of the Existing Power Plants in Cyprus, as year of January 2012[134][135]

Unit	Technology	Fuel Type	Capacity (MW)	Fixed O&M (€/kW Month)	Variable O&M (€/MWh)	Fuel Consumption[136] (MWh)
Moni Power Station						
ST1 – ST 6	Steam Turbines	Heavy Fuel Oil	180	4.00	4.20	0.348 tonne
GT1 – GT 4	Gas Turbine	Gasoil	150	1.25	6.00	0.360 tonne
Dhekelia Power Station						
ST1 – ST 2	Steam Turbine	Heavy Fuel Oil	120	2.41	1.33	0.277 tonne
ST3 – ST 4	Steam Turbine	Heavy Fuel Oil	120	2.41	1.33	0.277 tonne
ST5 – ST 6	Steam Turbine	Heavy Fuel Oil	120	2.41	1.33	0.277 tonne
ICE 1-2	Combustion E	Heavy Fuel Oil	100	1.57	3.20	0.205 tonne
Vasilakos Power Station						
ST1- ST 2	Steam Turbine	Heavy Fuel Oil	260	0.83	1.50	0.221 tonne
ST3	Steam Turbines	Heavy Fuel Oil	130			0.221 tonne
GT1	Gas Turbine	Gasoil	38	1.25	6.00	0.372 tonne
CCT1A	Combine Cycle	Gasoil	220	1.57	3.20	0.177 tonne
CCT2A	Combine Cycle	Gasoil	220	1.57	3.20	0.177 tonne
CCT1AA	Combine Cycle	Natural Gas	220	1.25	2.50	161 m^3N
CCT2BB	Combine Cycle	Natural Gas	220	1.25	2.50	161 m^3N
Wind Farm						
POWP1	Wind Power	Wind	82	5.90	0.00	0.00
LAAWP1	Wind Power	Wind	31.5	5.90	0.00	0.00

[134] With the exception of fuel consumption variables, the data presented here is obtained from Poullikkas and Kellas (2004, p. 527), Table 2: Economic Characteristics of Existing Generation Units.
[135] Baseload plants are composed of Vasilakos combine cycle, intermediate load plants are composed of Vasilakos steam turbines and Dhekelia steam turbines, and peak load plants composed of Vasilakos gas turbine, Moni gas and steam turbines.
[136] Average values from 2003 to 2009, except year of 2008. Fuel consumption parameters are estimated by dividing the total electricity generation to fuel consumption for the same year. For Vasilakos combined cycle plants, fuel consumption for Vasilakos combine cycle is assumed to be 80% of the most efficient plant in the system that is Vasilakos steam turbine.

Appendix B: Technical and Environmental Parameters of the Existing Power Plants in Cyprus, as year of January 2012[137]

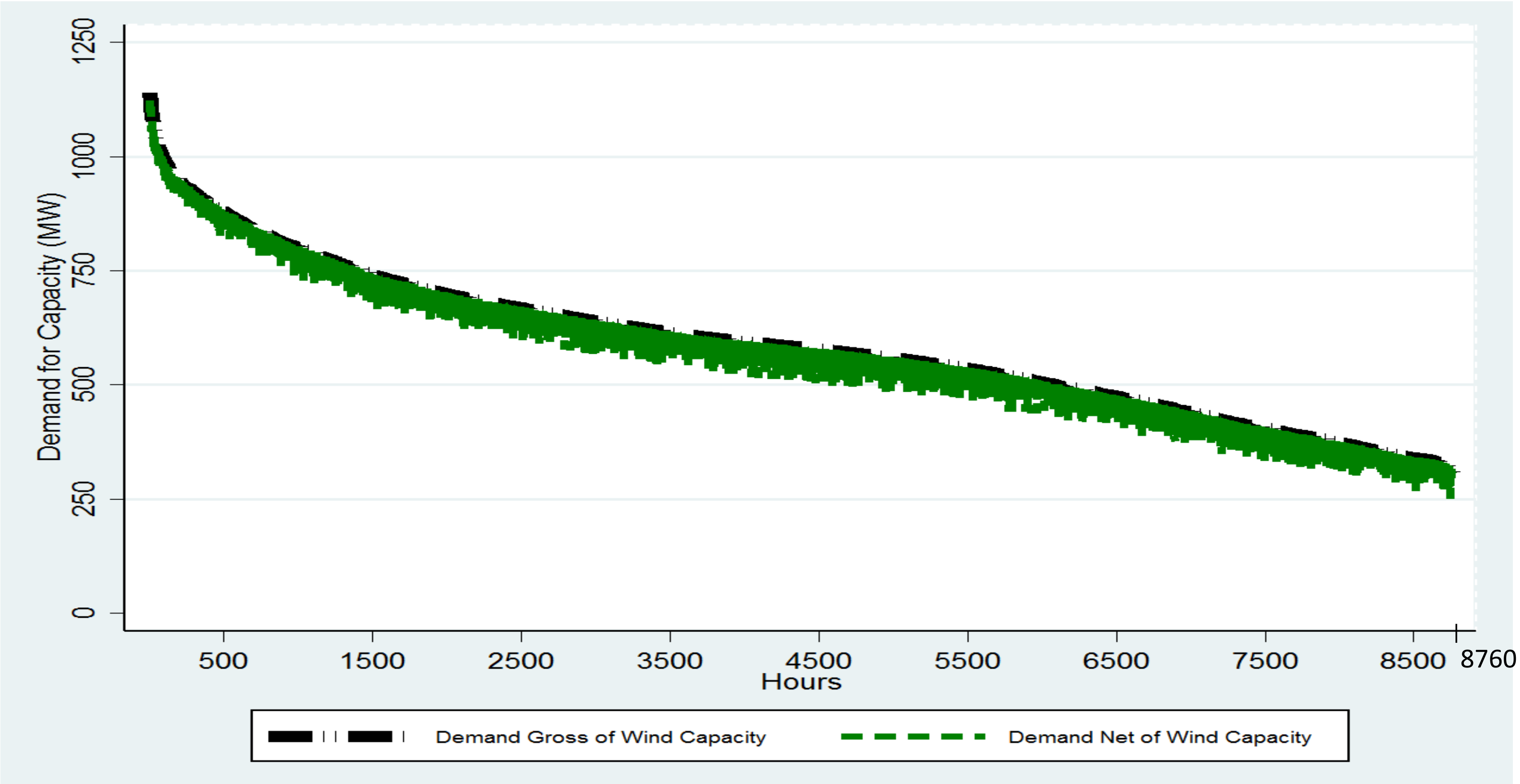
Unit	Commissioning	Decommissioning	Efficiency (%)	CO_2 Emission (Tonne/MWh)[138]
Moni Power Station				
ST1 – ST6	1966-1976	December 2015	25	1.069
GT1- GT 4	1992-1995	December 201X	34	1.165
Dhekelia Power Station				
ST1 – ST 2	1982	December 201X	31	0.855
ST3 – ST 4	1986	December 201X	31	0.855
ST5 – ST 6	1992-1993	December 202X	31	0.855
ICE 1-2	2009-2010	December 203X	41	0.635
Vasilikos Power Station				
ST1- ST 2	2000	December 203X	39	0.724
ST3	2007	December 203X	39	0.724
GT1	1999	December 202X	21	1.106
CCT1A	2009	December 2015	52	0.543
CCT2B	2010	December 2015	52	0.543
CCT1AA	2015	December 204X	52	0.181
CCT2BB	2015	December 204X	52	0.181
Wind Farm				
POWP1	2011	December 2031	---	---
LAAWP1	2012	December 2032	---	---

137 The relevant data presented here is obtained from Poullikkas and Kellas (2004, p. 526), Table 1: Technical Characteristics of Existing Generation Units.

138 Emissions from Vasilakos combined cycle are assumed to be 0.543 per tonne MWh of electricity produced, on the basis that the station is 10% more efficient than others.

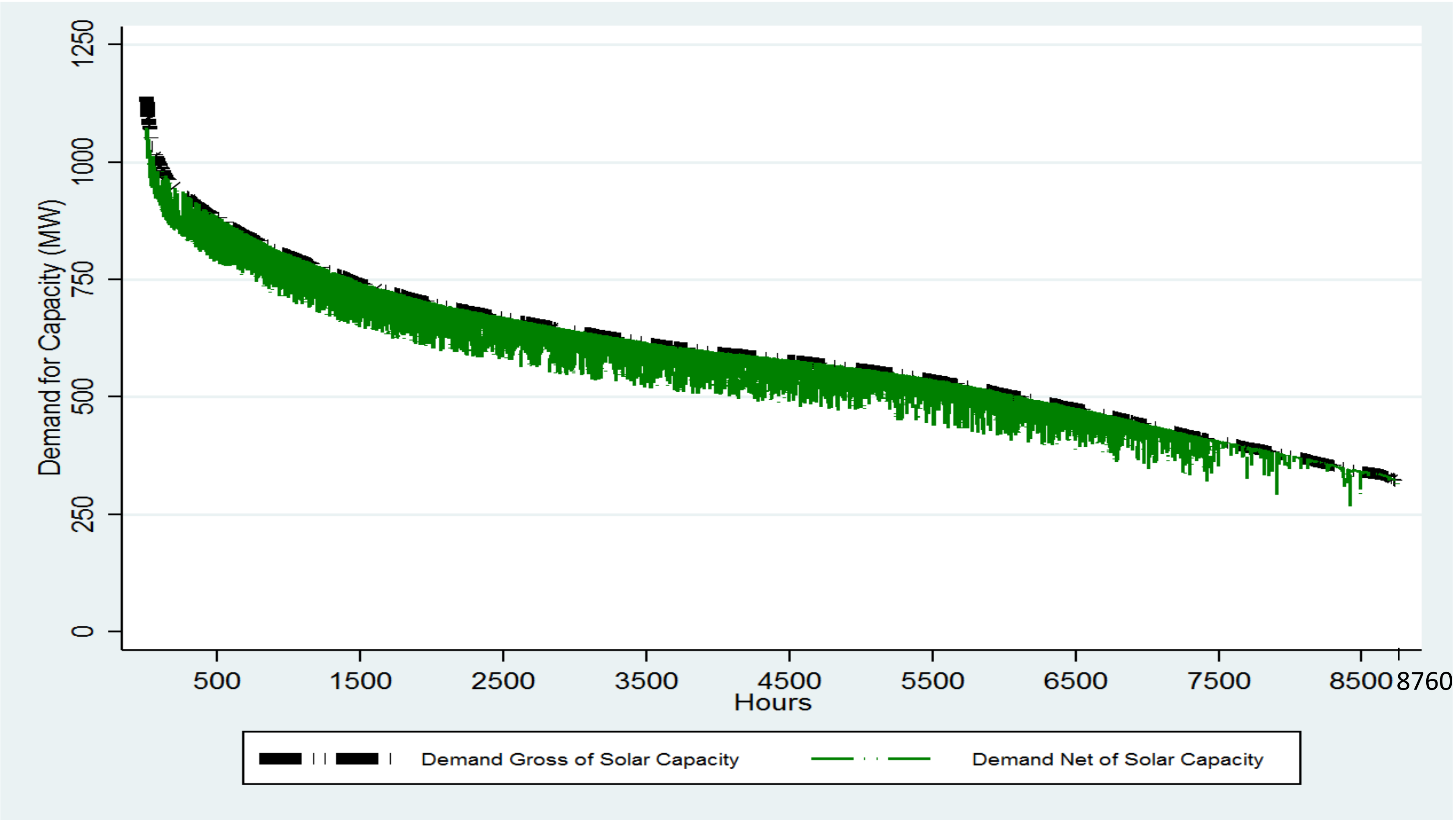
Appendix C: Demand and Renewable Power Coincidence in Cyprus in 2010

Figure 2.7: Annual Load Duration Curve in 2010 – with and without 100 MW Wind Capacity[139]



[139] Green area represents total wind electricity generated from 100 MW installed wind capacity.

Figure 2.8: Annual Load Duration Curve in 2010 – with and without 100 MW Solar Capacity [140]



[140] Green area represents total solar source of electricity generated from 100 MW installed solar PV capacity.

Appendix D: Total Hours Coincident between Paphos Wind Power and Electricity Demand

		Load Demand Normalized to Mean (%)					
		50-75	**76-100**	**101-125**	**126-150**	**>150**	**# of Hours**
	0-20	1197	1530	1521	594	123	**4965**
Wind LF	**21-40**	393	471	459	213	156	**1692**
(%)	**41-60**	216	609	594	246	177	**1842**
	61-80	48	129	54	18	0	**249**
	81-100	3	6	3	0	0	**12**
# of	**Hours**	**1857**	**2745**	**2631**	**1071**	**456**	**8760**

Source: own calculations.

Appendix E: Total Hours Coincident between Larnaca Wind Power and Electricity Demand

		Load Demand Normalized to Mean (%)					
		50-75	**76-100**	**101-125**	**126-150**	**>150**	**# of Hours**
	0-20	1197	1530	1521	594	123	**4965**
Wind LF	**21-40**	393	471	459	213	156	**1692**
(%)	**41-60**	216	609	594	246	177	**1842**
	61-80	48	129	54	18	0	**249**
	81-100	3	6	3	0	0	**12**
# of	**Hours**	**1857**	**2745**	**2631**	**1071**	**456**	**8760**

Source: own calculations.

Appendix F: Total Hours Coincident between Solar Power and Electricity Demand

		Load Demand Normalized to Mean (%)					
		50-75	**76-100**	**101-125**	**126-150**	**>150**	**# of Hours**
	0	9	117	178	151	199	**654**
Solar LF	**up to 21**	17	176	216	132	113	**654**
(%)	**21-40**	33	345	301	121	67	**867**
	41-60	68	446	337	92	38	**981**
	61-80	234	609	464	176	22	**1505**
	81-100	1445	1173	1072	383	26	**4099**
# of	**Hours**	**1806**	**2866**	**2568**	**1055**	**465**	**8760**

Source: Own calculations.

Appendix E: Multi Objective Multi Period Optimization Algorithm

The multi-objective optimization problem during the planning period may include minimization of total economic cost of power generation, minimization of emissions, minimization of external dependency in the form oil imports, etc. In the economic cost minimization problem, the objective is simply to minimize the sum of discounted total costs (fixed and variable costs) of the electricity supply over the long term horizon while a set of constraints are satisfied. In recent years, the environmental dimension of the electricity expansion is added into the planning problem with an increasing attention paid to emissions results from conventional electricity generation. The basic objective is then minimization of electricity generation costs from both economic and environmental point of view while a set of constraints are satisfied (Fichtner 2010). Hence, the problem is a *multi-objective (multi-criteria) optimization* problem such that the objective is to minimize the weighted sum of economic cost and pollutant emissions from electricity generation with mix of renewables given the set of constraints[141]. The problem defined in this paper is a key factor for achieving sustainable development (Afghan and Carvalho 2001; Dincer and Rosen, 2005).

The electricity expansion and generation problem is already defined as a multi-objective problem aiming to minimize two conflicting objective functions simultaneously. In most cases, there is no single unique solution with respect to multiple objective functions but there exists a set of Pareto optimum (Edgeworth-Pareto) solutions that satisfy the model constraints (Zitzler et al. 1993). To

[141] Step by step method for solving single - objective optimization problem is explained in Chapter 5: A simplified Look at Generation Capacity Addition", Mazer (2007, pg. 135-136). In this paper, robust formulation for the multi-objective problems will be developed for an improved solution with simplification in order to avoid complicated engineering and technical details. Also, the problem stated above is defined as key factor for achieving sustainable development (Dincer and Rosen, 2005).

illustrate the problem, let f_1 to be the function for the least cost and f_2 to be the function for the least emissions from electricity generation.

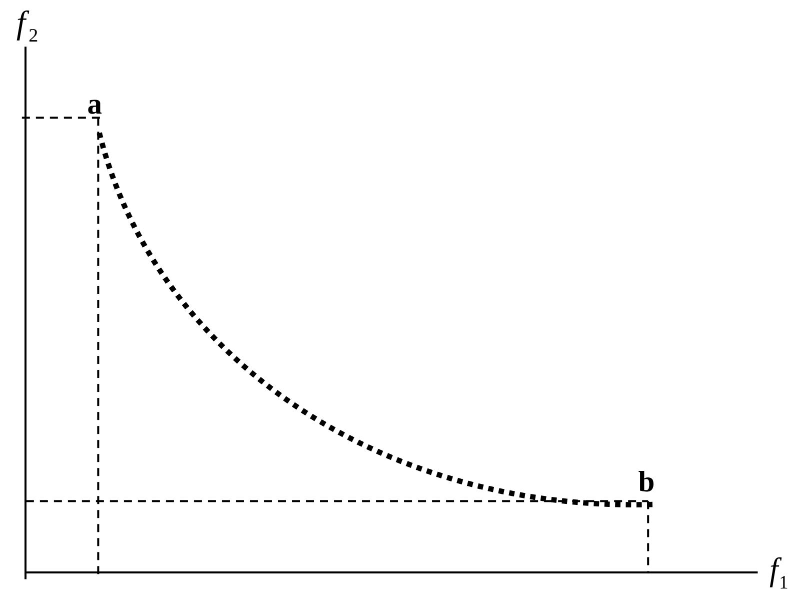
$$\min \quad (f_1(x), f_2(x), \ldots, f_n(x))$$
$$\text{st.} \quad x \in S$$

where $f_1(x), f_2(x), \ldots, f_n(x)$ stands for set of objective functions, x stands for vector of decisions variables and S stands for feasible region that includes set of solutions that satisfy all constraints The aim is to determine the set of x^* values from vector of x which satisfy model constraints and yield optimum values of all the objective functions. In words,

> *"... x^* is Pareto optimal if there exists no feasible vector of decision variables $x \in S$ which would decrease some criterion without causing a simultaneous increase in at least one other criterion..."* (Zitzler et al. 1993, pg. 23)

The vector of these solutions in the *Pareto optimal* set is called *non-dominated* solutions which are plotted in the *Pareto frontier*. To illustrate the problem graphically, let once again f_1 be the function for the least cost and f_2 to be the function for the least emissions from electricity generation

Figure 2.9: The Pareto frontier of multi-objective electricity generation problem

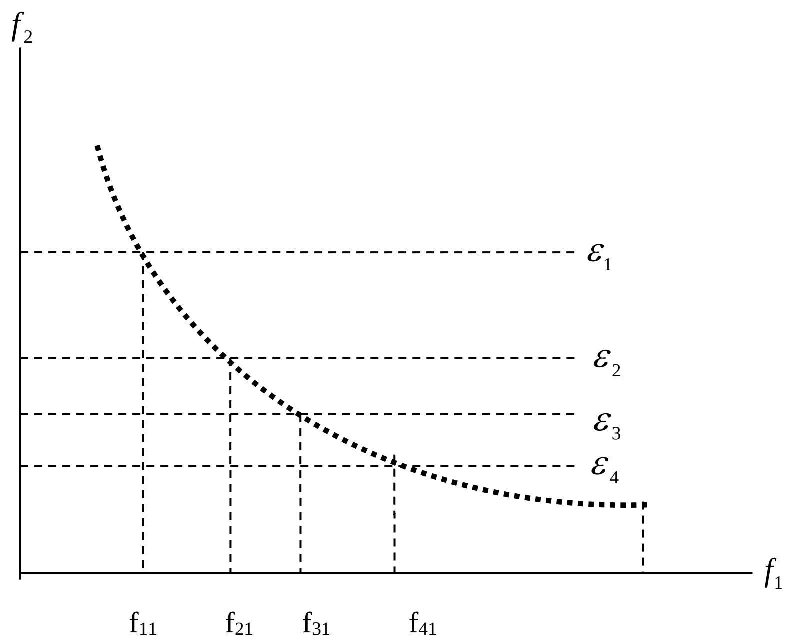


Widely applied solution methods for solving the multi-objective problem are the weighting approach, *ε*-constraint approach and the scalarizing function approach etc. (Zitzler et al. 1993). In the w*eighting* method the weighted sum of objective functions are optimized by assigning weight to each function while in the *ε-constraint* method; one objective function is optimized while other objective function (s) is included in the constraint sets. Using the ε-*constraint* method, the trade-off between the objectives can be easily computed and the *Pareto optimal - nondominated* solutions for the model can be obtained (Mavrotas, 2006; 2009). Therefore, the use of the ε-*constraint* method would be appropriate in our analysis as weights are unknown. Suppose, emissions are written in the constraint function and cost minimization is written as the objective function. Algebraically,

$$\begin{array}{ll} \text{min} & f_1(x) \\ \text{st} & x \in S \end{array}$$

where, $f_1(x)$ stands for set of objective function, x stands for vector of decisions variables, S stands for feasible region that includes set of solutions that satisfy all constraints in which $f_2(x)$ - emissions - is also included in the constraint set.

Figure 2.10: The Pareto frontier of multi-objective electricity generation problem with ε - Constraint



CHAPTER 3: REAL-TIME PRICING OF ELECTRICITY IN THE CYPRIOT ELECTRICITY MARKET

3.1 Introduction

The ambition to achieve maximum productive efficiency in the electric power industry and to lower power costs (i.e. electricity prices) by increasing competition between suppliers resulted in a movement towards liberalizing energy markets in many parts of the world (Batstone, 2010; Sioshansi, 2006; Blumstein *et al.,* 2002; Kleit and Terrell, 2001; Martin and Vansteenkiste, 2001; Joskow, 1997; Hogan 1993). In the EU, the Directive 96/92/EC and Directive 2003/54/EC of the European Parliament aim to liberalise (i.e. deregulate) its generation and supply of electricity whilst maintaining the naturally monopolistic structure in both the transmission and distribution system in the electricity industry[142]. The objectives of these directives are to separate the generation and supply of electricity, to introduce competition in the industry and to regulate the transmission and distribution systems.

Meanwhile, many countries have made so-called Copenhagen pledges to reduce greenhouse gas emissions within the next decade and participating states are revising their energy policies based on this. EU policies for meeting the renewable and emission reduction targets mainly come from

[142] Newbery (2002) also investigates the problems of restructuring the electricity industry in the EU which arise due to the legislative and regulatory constraints of the union. He argues that the prices in liberalized electricity markets may increase if the power market is lacking enough transmission capacity and sufficient generation capacity, and not contestable enough. Therefore, the policy makers of the EU should carefully work on appropriate design of both legislative and regulatory aspects of the power market before the liberalization; otherwise the negative economic consequences of weak legal infrastructure arrangements in its power market can be tremendous. Green (2006) and Green *et al.,* (2006) provide the liberalization activities and indicators for EU electricity markets, respectively. Green (2007) investigates the introduction of competition into the EU as whole and argues that it is not an easy task due to low capacity cross border interconnections and differences in liberalization across member states. Trevino (2008) also supports the arguments made by Green (2007).

substituting renewable fuel sources for fossil fuels (e.g. increasing the share of renewables in electricity generation) and improving energy efficiency in both industrial and domestic loads (e.g. energy efficient appliances). With respect to renewable electricity targets (i.e. RES-E), various renewable energy roadmaps such as Directives 2001/77/EC, 2003/30/EC and 2009/28/EC of the European Parliament promote the use of renewables and support for their access (e.g. fixed FITs and ETS emission trading scheme) in the electricity market (Cansino *et al.,* 2010)[143].

The electricity sector in many EU countries is therefore experiencing simultaneous transition in competitive opening of their electricity markets with an increase in the share of renewable power in electricity generation. The transition toward competition and decarbonisation alter the way that today's electricity market operates. To be more precise, many countries including EU member states are experiencing profound regulatory and operational changes in their electricity market. The simultaneous movement leads market principles to be used in design and implementation of energy policy measures to facilitate the liberalization of electricity markets (Jensen and Skytte, 2002).

Although wholesale markets have been open to competition during the deregulation of many electric utilities in Europe, many end-use customers still pay *fixed regulated retail prices*[144] for their consumption that are almost time-invariant within a season. But, retail prices do not vary over time even in competitive retail market environments due to regulatory barriers as well as traditional metering technologies[145], something that fails to send real-time price information to

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[143] For more detailed information on the choice of support policy within the EU member states, see European Commission, Energy Policies, Renewable Energy, Electricity
http://ec.europa.eu/energy/renewables/electricity_en.htm
and European Commission, Renewable Energy Policy Database and Support, Legal Sources by Country
http://www.res-legal.eu/search-by-country/

[144] Fixed pricing is also referred as time-invariant pricing.

[145] Even when legal constraints are removed and regulators allow consumers to pay their bills at time-varying prices, the use of traditional metering devices and lack of technical infrastructure remains a serious obstacle. The use traditional metering devices meters allow consumers to observe their accumulated consumption over the billing period, mostly monthly. Hence, their monthly bill shows their accumulated consumption and flat tariff rate they have to pay for the

end-users in Europe (Bompard *et al.,* 2007; IEA, 2003) (ECME Consortium, 2009) or in those states in the US that have open retail markets (Costello, 2004). The application of fixed pricing of electricity today is justified for various reasons including reliability, availability (keeping the lights on) and affordability of electric power. Therefore, electricity planning problems even today merely focus on meeting peak demand and preserving a reserve margin to maintain the desired level of reliability in power supply that has assumed price inelastic demand – so electric utilities inevitably incur high total costs of meeting the growing demand for electricity in a reliable way (Cutter *et al.,* 2012; Kim and Shcerbakova, 2011)[146]. Nevertheless, this assumption comes from application of the fixed rate of electricity inherited from the vertically integrated public utility that existed before restructuring of the sector.

The main problem with the restructuring and decarbonisation policies in electricity markets is that they often rely on supply side market forces alone to meet the growing demand for energy and reducing the emissions from electricity generation (Wellinghoff *et al.,* 2007; Hunt, 2002). The policies are implemented under the assumption that consumers are not willing or are unable to respond to changing electricity prices. But the empirical literature based on pilot programs from voluntary participation reveals that consumers are price responsive to varying degrees[147]. This

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consumption. Therefore, these meters do not allow real or near real-time prices to reach retail customers, so that they might react to changing prices and consume different quantities of electricity and pay different prices for their consumption over a given time.

[146] System reliability in the short-term refers to a perfect balance of power supply and demand in real time. System reliability over the long-term refers to adequate investments in both generation and transmission lines. Before competition, public utilities were responsible regarding preserving the reliability of the system. Due to the recent regulatory and operational changes in the electricity industry, there are two important supply-side issues in competitive markets to which regulators must pay particular attention. Firstly, private investors decide what kind of power plant, when and where to construct the power plant(s) so that they earn the highest return from their investments. Secondly, maintaining the generation adequacy with growing loads requires investors to build new power plants. Therefore, in addition to electricity pricing, government regulators must ensure that investors in power generation have favorable market environments operating in competitive electricity markets, as clearly stated by Sioshansi (2001).

[147] See for example, Allcott, 2011; Faruqui and Sergici, 2010; Filippini, 2010; Lijesen, 2007; Wolak, 2006; Goldman *et al.,* 2005; Borenstein, 2002; Patrick and Wolak, 2001; Braithwait and O'Sheasy, 2001; Taylor and Schwarz, 2000; Filippini, 1995). Participation from voluntary programs might mislead policy makers; some people might not be price-responsive at all, so these responses may or may not be generalized for the entire population (Joskow and Wolfram, 2011). At the same time, the design of pilot programs and selection of target populations are very influential on the estimations of these elasticities. We need to state here that not only is it the industrial users who are sensitive to price changes in the electricity market. For example, Patrick and Wolak (2001) show that large as well as medium size end-use consumers in the England and Wales power market are highly responsive to half-hourly electricity pricing. Another example includes TOU experiment in California which show that in

implies the potential participation of the demand side in the wholesale market is still limited to the large electricity consumers only such as industrial users (Barbose *et al.,* 2004)[148].From the economic efficiency point of view, the absence of time-varying prices in retail markets is the main shortcoming of the functioning of the electricity market to achieve efficiency. This is why academics and policy makers now pay a lot of attention to dynamic pricing of electricity in the electricity markets: dynamic pricing of electricity allows retailers to sell electricity at a price which converges to its marginal cost of production.

In this paper, we will analyse the impacts of time-varying electricity pricing (i.e. dynamic pricing) on the Cypriot electricity market. To our knowledge, such screening of impacts from implementing dynamic pricing of electricity is yet to be explored for Cyprus. This topic is worth investigating for Cyprus, because installation of smart meters into homes will take place in the future. Based on Directive 2009/72/EC, EU member states will have to install smart meters for at least 80% of their domestic consumers by 2020[149] . In this paper, we will address the implications of real-time pricing on demand, power prices, renewable power generation (i.e. wind and solar) and on the emissions from electricity generation. By answering these questions, we believe this paper may be used as a future policy guide for the implementation of such programs while a country is moving toward green technology in its electricity supply and aims to reduce emission from electricity generation.

3.2 Price Setting Mechanism in Electricity Markets

The three key functions of the price mechanism in the market are the signalling function, transmission of preferences and the rationing functions which are all described in the 'invisible

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addition to industrial users, residential as well as small and medium size commercial customers also respond and certainly reduce their electricity usage during peak hours (Faruqui and George, 2005), now but also in the past (Caves and Christensen, 1980).

148 Unresolved issues and uncertainties associated with the application of marginal cost pricing such as technical, political and society level barriers are outlined in section 3.5 of this study.

149 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF

hand' price mechanism introduced by Adam Smith. The price of a service, for example an electricity service, should inform the seller when to produce and should inform consumers when to purchase. Wholesale electricity prices are largely determined by fuel prices and carbon prices, and changes in the mix of the regional generation portfolio[150]. Given that the marginal costs of thermal generators are dominated by fuel costs, so volatility in fuel prices is transmitted to the price of electricity. The variation in peak and off-peak electricity prices comes partially from volatility of fuel prices, but mainly from demand and capacity balance. In a similar fashion, emission prices may respond to changes in fuel prices that may lead to more fluctuations in electricity prices in power market (Green and Vasilakos, 2011).

Electricity is a special form of non-storable commodity that differentiates it from other storable commodities and so pricing electricity correctly throughout the day is not an easy task. Firstly, electricity cannot be stored in large quantities, so the supply of power has to meet demand for power at every second in order to avoid both shortages and/or surpluses of electricity. Therefore, electricity systems face instantaneous fluctuations in their demand and supply. Secondly, power plants differ in terms of the cost they incur for an additional MWh of electricity generation (marginal costs) because each technology requires a different type and amount of fuel to generate a unit of electricity, and has differing non-fuel operating costs[151]. That is to say, peak electricity and off-peak electricity are different commodities with varying marginal costs to suppliers and marginal value to end-use consumers. Therefore, the fluctuating demand for electricity is supplied from a heterogeneous mix of power plants, giving variations of marginal costs of power supply throughout the day. Thus, the value (i.e. price) of electricity at peak times is ideally different than off-peak times, partly to do with the demand for electricity and partly

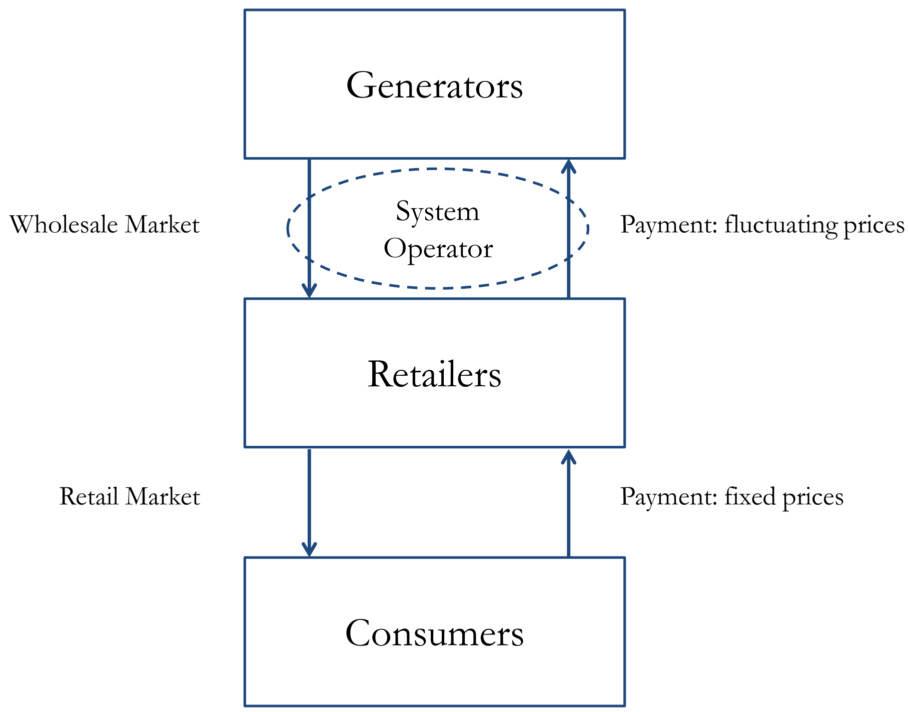
[150] Therefore the marginal cost of generating electricity depends on the amount of fuel consumption per MWh, and CO emissions per MWh from consuming fuel.
[151] We expect electricity prices to be cheap in France and Canada due to a high proportion of nuclear and hydro plants, similarly in Germany due to high proportion of locally mined coal in its power generation. For price comparison in selected EU countries, see Murray (2009, p.53). These prices do not include fixed additives.

with the supply of electricity (cost of additional supply and non-storability). The short-run operation of the power market gives a signal to the power industry that has an impact on future investments in generation capacity (to both the type of generation capacity and the timing of investments) in the long-term.

In most electricity markets, consumers purchase their electricity in competitive retail markets and retail companies supply electricity to their customers from their purchases in a competitive wholesale market, as shown in Figure 3.1. The wholesale market model is both a partial and first step towards deregulation (introduction of competition) in the electricity supply industry. In this market, long-term contracts and spot contracts allow trade between retailers and generators in an auction (Trevino, 2008). Different from the traditional approach, deregulation of wholesale power markets allows system operators to decide on dispatch decisions by simply matching power supply bids (based on short-run marginal costs of generators) with forecast demand where market prices are set according to the highest bid accepted by the system operator.

In most electricity markets, the wholesale prices vary constantly and actually reflect fluctuations in supply/demand interaction in time (say within days and seasons) and location (say network node). The system operator brings retailers (load serving entities) and generators together and allows trading of electricity based on these time-varying electricity prices. The supply curve of the wholesale market is derived from per unit marginal costs of production by each generator where the intersection point of demand for and market supply of electricity determines the equilibrium price. As we move toward peak demand hours, we expect incremental costs of power supply to increase due to system capacity constraints. The price of electricity might be even higher than marginal costs in these hours (Borenstein, 2000), so that incentives are to invest in additional capacity in these hours[152].

Figure 3.1: Trading Mechanisms in Electricity Market



In power markets, the supply curve (merit-order curve) ranks the power from each generator based on their cost curves - from the lowest marginal cost/MWh generator to the highest marginal cost/MWh generator to meet the demand for electricity in any particular hour[153]. In other words, it shows utilities' time-varying marginal costs to meet the changing demand for electricity. End-use consumers, however, do not pay wholesale prices, but they pay retail prices. Retail prices include the wholesale price plus all adders such as fixed transmission and distribution charges, grid charges and consumption taxes (Grohnheit et al., 2011; Bode, 2008). Without any doubt, retail prices always decrease in response to a decrease in wholesale prices – if

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[152] Note that this is not the exercise of market power which we will discuss later. This can be seen as premium to let generators cover their fixed costs.

[153] Because of the fluctuations in electricity demand over time (reflected by the annual load duration curve), the potential cost savings from any kind of renewable generation technology is measured by comparing the cost of particular renewable generation with the cost of thermal generation.

these adders remain the same. Nevertheless, end-use consumers' willingness to respond to changing wholesale prices depends on the proportion of wholesale prices in the retail price they pay (Grohnheit *et al.,* 2011)[154].

In competitive markets, the system marginal cost determines the bid price of individual power plants operating in the competitive market. Therefore, the system marginal cost is a parameter that decides and sets optimal dispatching decisions in power supply. The wholesale electricity prices represent time-varying electricity generation costs but consumers pay the highest bid offered in trading. This is called a marginal bid or price that all generator owners receive from their sales. The lower the variable cost of generating electricity, the less it can afford to bid, so the higher the likelihood that the generator is included in the dispatch schedule[155,156]

Renewable energy sources have dispatch priority in the system. They reduce the load (demand) that thermal generators have to supply and the prices they receive for the energy they supply in the market[157]. In other words, thermal generators only supply the residual load after deducting the quantities of renewable generators. We show this by reducing the demand for thermal power in

[154] As of 2011, the share of wholesale costs in retail electricity prices in Cyprus is 88%, which is the highest of all EU countries.

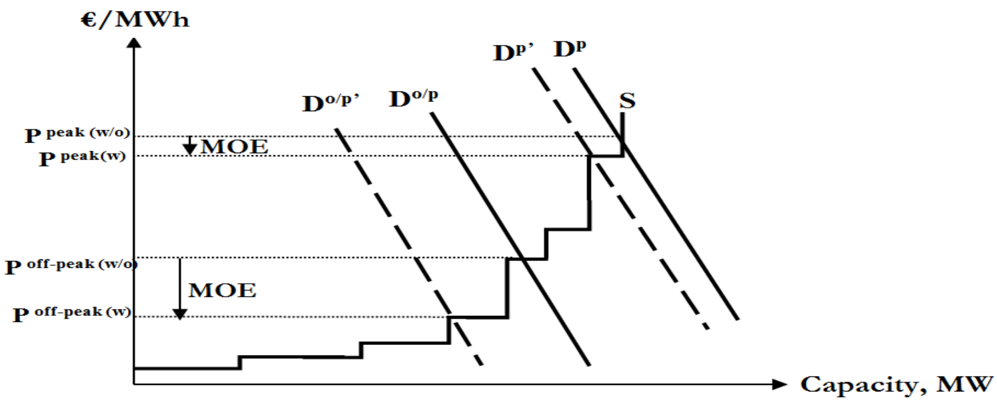
[155] In some cases, system operator may choose a higher marginal cost plant with a relatively lower start up than a lower marginal cost plant with higher start-up costs. It is also worthwhile to state that in comparison to spot markets, a day-ahead market promotes the demand response (Hunt, 2002). Not only does it promote the demand response, but it also lowers electricity prices by reducing the start-up costs of generators and prevents generators from exercising market power by blocking prices in advance. That is to say, the day-ahead market allows the system operator great flexibility in terms of time for dispatching the decision of generators.

[156] Alternative to the marginal bid pricing of electricity, consumers may also pay their electricity based on pay-as-you-bid. In this case, consumers pay for an individual generators bid so they end up with lower electricity bills from their purchaser. However, pay-as-you-bid may not work in practice as generators have to guess about market clearing prices and may offer more than their true marginal cost. As a result, this would distort the dispatching decisions in the electricity market. This argument for pay-as-you-bid is invalid if all traders in the market have access to good and sufficient information, so both trading options would give the same market price.

[157] Due to differences in timing and predictability, wind has different impacts on the system than that of solar; therefore impacts of RES energy sources are not the same across different RES integrated into the system. Increasing renewables in the electricity market increases the uncertainty in power markets arising from the intermittent nature of renewables (Twomey and Neuhoff, 2010). One way of reducing the uncertainty associated with renewables is better forecasting on the renewable power output which in turn greatly reduces both the costs of renewable integration and additional market risks due to uncertainty (Lew *et al.,* 2011). In this research, we assume perfect predictability of wind and solar.

figure 3.2; use of either demand shift or supply shift practically provides the same recommendations. For instance, integration of these renewable power sources shifts the supply curve to the right which in turn results in lower power prices in the electricity market, the so called *merit order effect* (Bode, 2006; DeMiera *et al.,* 2008; Butler and Neuhoff, 2008; Weigt, 2009; Fischer, 2009; Neubarth *et al.,* 2006).

Figure 3.2 Impacts of Wind on Thermal Demand and Market Prices



3.3 Microeconomic Analysis of Efficient Pricing of Electricity

The price of electricity must yield the correct amount of generation capacity with its efficient utilization, and must cover the full social costs of the resources used in its supply (Steiner, 1957)[158]. The efficient price policy in electricity is an old phenomenon and initially started with the pioneering discussion of the peak-load problem[159]. The peak-load problem arises in commodities that are not storable during the low demand period to make it available when demand is high (e.g. electricity, airline, hotel, transport services). Hence, it is necessary to install

[158]Jenkins and Evans (1978) earlier point out utilities must use the social discount rate rather than the private cost of resources in order to avoid inefficiency loss from production of electricity for consumption. The financial discount rate is different to the social discount rate if markets are distorted. So resource costs and savings must be evaluated at this social discount rate, because it captures these distortions in an economy.

[159] For a survey of the literature on peak-load pricing of electricity, see Crew, Fernando, and Kleindorfer (1995) and for a recent bibliography of dynamic pricing of electricity as well as TOU pricing, also see Enright and Faruqui (2012).

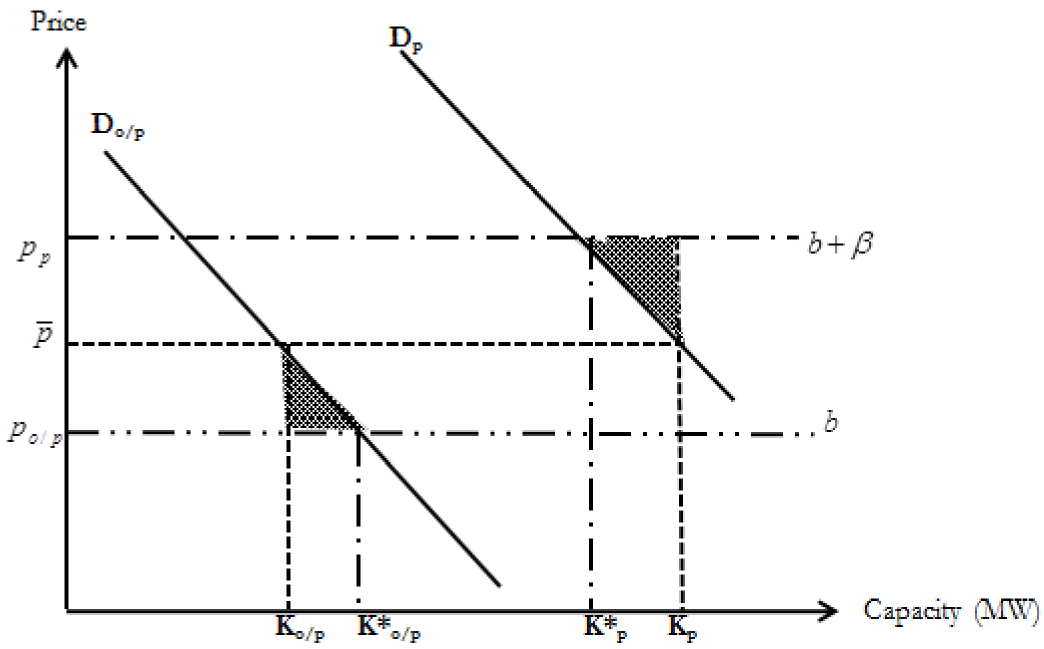
additional peaking capacity to meet the peak demand during peak demand periods. The problem with this peak capacity is that it is underutilized, so price-setting must able to cover these peak costs investments from technology itself plus from its underutilization. The old theoretical literature tries to solve the problem of the efficient allocation of these costs. The idea of moving away from time-invariant electricity prices to peak-load pricing is then tied to variations in the marginal cost of generating electricity and the capacity cost from additional investment.

The literature's canonical argument in peak-load pricing of electricity is that off-peak consumers must pay marginal running costs and peak consumers must pay for both marginal running costs plus marginal capacity costs for their electricity consumption as additional peak capacity is costly (Wenders, 1976; Turvey 1968; Boiteux, 1964; Steiner, 1957). As demand for electricity moves toward peak capacity, incremental costs of power supply increase from additional capacity with higher operating costs. By charging different prices for peak and off-peak consumers, utilities are able to cover higher cost of peak electricity generation.[160] The discussion on efficient pricing of electricity in current electricity policy debate is also about price differentiation over time – setting the price of electricity equal to the instantaneous cost of producing it - and it is referred to as the time-varying price of electricity (i.e. real-time pricing).

[160]With an inclusion of power outage costs into electricity prices, off-peak consumers might also pay more than the marginal cost of electricity (Crew and Kleinderfor, 1976). To illustrate, if off-peak consumers take into account reliability of supply and perceive it at high level (e.g. low number of outages), they might also willing to pay for electricity charges plus quality of supply premium to avoid such outages. In this regard, the regulated bodies (e.g. electric utilities) must take into consideration consumer preferences for service quality in power supply before the implementation of reliability measures. The outcome is economically feasible because revenues of the electric utility from sales and the consumer surplus from consumption will both increase. This willingness to pay varies across consumer types (residential, commercial, and industrial), and their individual willingness to pay depends on many factors including duration of outages, time of day of occurrence, advance notification of outage, income of consumers, average electricity bill paid, availability of back-up systems (e.g. generator ownership). Practitioners apply valuation methods to estimate consumers' WTP to mitigate such power outages. To estimate these WTP estimates, choice experiment methods with different hypothetical scenarios are widely used in the literature.

In Figure 3.3, the marginal cost of supplying electricity in peak hours exceeds the retail price in peak hours $(b+\beta > \overline{p})$, whilst off-peak retail price of electricity exceeds true marginal cost of supplying electricity in off-peak hours $(b < \overline{p})$. If retail electricity prices do not reflect the hour-by-hour variations in the underlying cost of electricity, end-use customers consume too much electric capacity (means energy at the same time) at peak times $K_p > K_p^*$, but they demand too little during off-peak hours $K_{o/p} < K_{o/p}^*$. So, end-use consumers with a fixed tariff just consume what they want and pay for it; there is no incentive for consumers to shift their consumption away from high cost of supply hours to low cost of supply hours with plenty of unused capacity available. The outcome of this distorted consumption choice from flat retail tariffs inevitably leads low utilization of generating capacity in short-run and distorted investment in generation and transmission capacity in long-run (Joskow and Wolfram, 2012; Tiptipakorn and Wei-Jen, 2007; Flippen, 2003; Turvey, 2003; Ilic *et al.,* 2002; Dewees, 2001; Chapman and Tramutola, 1990).

Figure 3.3 Representation of Steiner's (1957) Peak Load Pricing with two-period demand



The outcome of such fixed pricing is more electricity consumption than the optimal quantity at peak times (over consumption), but less than the optimum at off-peak times (under consumption). The shaded triangles in the figure above represent the welfare loss at a societal level from fixed pricing of electricity. This short-term inefficiency in allocation of supply resources will have long-term adverse impacts through inefficient and high costly investments in generation and transmission capacity. The increasing demand for capacity at peak times will not cause blackouts in the system, but rather the expansion of capacity in generation in order to reliably meet this growing demand and maintain the reserve margin in the system. With a high growth in demand for peak capacity, the requirement for additional generation capacity might take place even over a shorter time (Albadi and El-Saadany, 2008; Borenstein, 2005). Thus, an increase in demand for capacity will bring new investment and ultimately the need to upgrade transmission capacity in order to avoid congestion in transmission lines (i.e. reliability reasons). Therefore, incorrect pricing of electricity harms overall grid use efficiency and incurs cost to the economy in the form of higher infrastructure investments.

Another serious problem with flat (average) electricity pricing is that end-user customers who consume more electricity during off-peak (low marginal cost hours) inevitably subsidize peak consumers (high marginal cost hours)[161]. From the equity perspective, this cross subsidisation of electricity from fixed pricing is even more severe if substantial off-peak consumption comes from low-income customers. Why should low income households pay for electricity costs of rich households? Why should low-income customers pay for air-conditioning usage by rich customers during hot summer days of the year?

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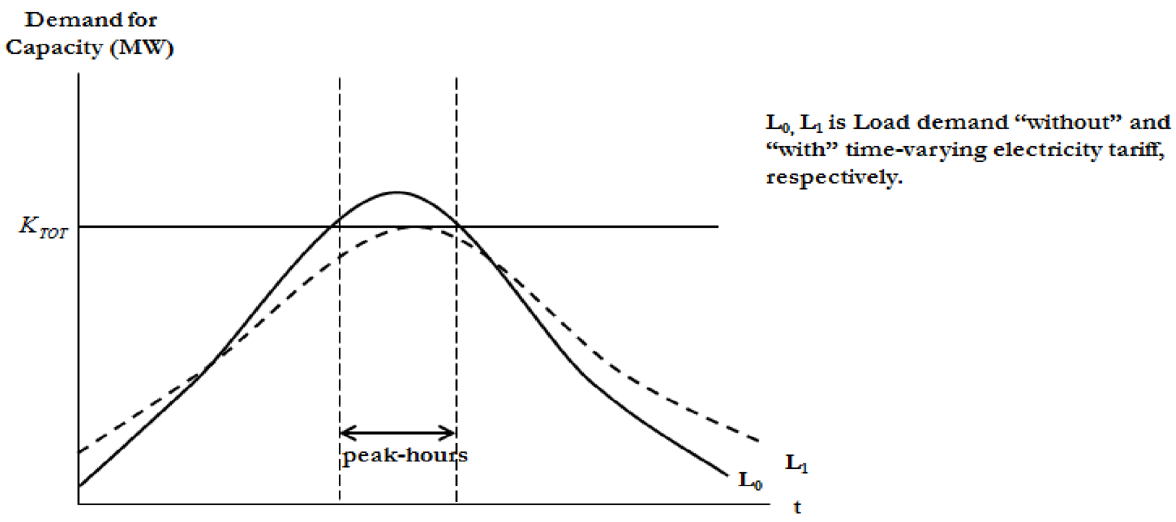
[161] Actual distribution of hourly wholesale energy and retail prices in California during the summer of 2000 shows that more peaky consumers pay less, but mainly off-peak consumers pay more than they should (O'Sheasy, 2003:49).

The lack of demand response in the market clearly has adverse implications in system operations. The precise argument is that demand participation in electricity market design would be promising and in fact play a significant role in achieving an efficient use of scarce resources in this sector (Joskow and Wolfram, 2012; Allcott, 2011; Orans *et al.,* 2010; Chao, 2010; Alvarez-Bel *et al.,* 2009; Zarnikau, 2008; Spees and Lave, 2007; Harrington, 2004; Braithwait *et al.,* 2002; Borenstein *et al.,* 2002a; Borenstein *et al.,* 2002b; Hunt, 2002; Faruqui and George, 2002). The electricity industry will continue to be vulnerable and less efficient until such demand responses are pursued. Hence, letting consumers both determine and react to electricity prices will foster reliability in the system, increase efficiency in the use of resources and increase security of the power supply rather than increasing the unused generation capacity in the system.

Figure 3.4 The Effect of Average Pricing vs Marginal Cost Pricing on Demand (Supply) for Capacity



The primary purpose of moving away from fixed (average pricing) pricing of electricity is to eliminate the disconnection between wholesale market and retail prices, so that the deadweight losses in electricity services due to the flat rate disappears. Therefore, the market itself alongside smart meter technology must allow consumers to have access to wholesale market information and to observe time-varying retail prices, so they can change their electricity consumption in response to these prices (Braithwait *et al.,* 2002; Borenstein, 2002; FERC, 2002; Caves *et al.,* 2000).

The immediate effect of time-varying pricing would be such that consumers shift their consumption away from the times of peak demand (peak clipping), and toward times of lower demand (valley filling / load shifting), as shown in Figure 3.4. Alternatively, they shift their consumption to a time period when supply is plentiful so electricity prices are usually low and also by foregoing some electricity consumption during at high price hours when supply reliability is jeopardized. In the short-run, time-varying prices will tend to reduce use of low capital cost /high marginal cost peak generation whilst increasing the load factor of high capital cost/low marginal cost. By better utilization of power supply resources, electricity prices would reflect the true marginal cost of production – the price of electricity must move with the peak[162]. Hence, the primary motivation to implement time-varying electricity prices is to move electricity prices closer to their actual marginal cost of electricity and in addition to reduce peak electricity consumption and shift some of the consumption to off-peak hours. In other words, peak reduction alone is not the primary goal of implementing RTP pricing.

3.4 Dynamic Pricing of Electricity in Practice

3.4.1 Overview

Time-varying electricity pricing is not an impact-neutral policy across demanders and suppliers of energy. That is to say, the distribution of costs paid and benefits received from introducing dynamic pricing by consumers vary across market participants (Borenstein, 2007; Taylor *et al.,* 2005). A change to time-varying electricity pricing will create both winners and losers Demand response programs will initially alter the shape of load demand which will in turn ultimately

[162] The price of electricity equals marginal costs of the last unit generated as long as plenty of spare capacity is available at that hour. This price equals the marginal cost of the last unit generated plus the rationing element when demand for electricity exceeds the capacity at that hour. We will discuss this later in detail, following the exposition by Green (2000).

change the dispatching of power plants and thus the supply mix running in the system with different costs and emission levels. It is noteworthy to state that a shift in the load demand depends on the willingness and ability of end-use customers to react to price changes. This is reflected in the own and cross-price elasticities that vary across demand side participation programmes and participation by each customer class (residential, commercial and industrial).

One direct major implication of time-varying pricing of electricity (through smart meter technology) is that consumers have direct control over their power expenditure. Consumers can manage their bills by modifying their demand for electricity by time and quantity. To put it differently, consumers will shift their household activities to off-peak periods such as dishwashing, cloth washing, ironing, and water pumping, etc.[163]. So, one major advantage for consumers is that they might take advantage of lower prices. Consumers might save on their electricity bills, if they are price-responsive and able to modify their load profile in response to changing hourly electricity prices (Herter, 2007)[164]. Consumers with RTP might move their consumption towards times when supply is plentiful, such as off-peak hours. These reductions in demand for electricity, especially during peak demand time will also reduce the electricity bills of consumers from lower electricity prices (Marwan and Kamel, 2011; Sezgen *et al.,* 2007; Kirschen, 2003; Caves *et al.,* 2000). Clearly, these bill savings are mostly realized by consumers who are more off-peak oriented.

Note that lower electricity prices may also induce consumption, so overall consumption of electricity may increase total energy bills for these customers. Given this, we cannot strictly argue

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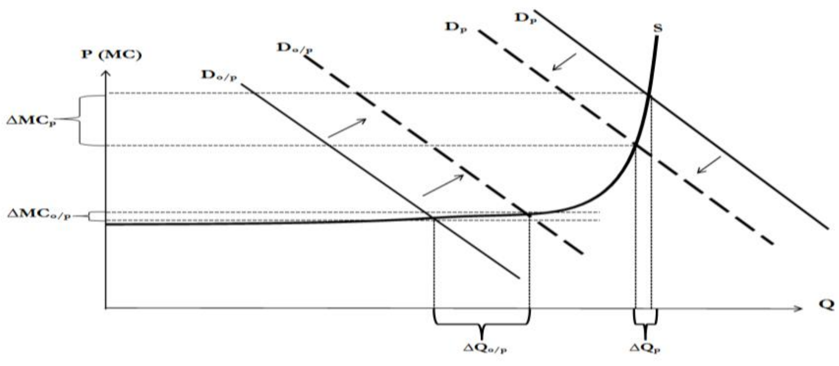
[163] See Kolabasa (2010) who directly investigates the impacts of RTP on these types of household activities in Germany and changes in the system balancing costs with wind integration. He shows that these will reduce the system balancing costs and allow utilities to integrate the variable wind sources at lower costs.

[164] Celebi and Fuller (2012; 2007) employ a time lag response model in their empirical analysis for the Ontario electricity market that allows consumers to adjust their consumption from the current to the next invoice period based on changes in the prices of electricity.

that all consumers will save from energy bills just because they will reduce their total electricity consumption in peak hours. Consumers might have good planning of their consumption if the real-time prices are sent to consumers long in advance (Taylor and Schwarz, 2000; Steen *et al.,* 2012), but this might increase the demand during peak hours (Steen et al., 2012). Note that the shift in consumption is voluntary and any loss of comfort is by choice. This shift might also reduce the risk of power outages, or the number of temporary electricity interruptions they may experience in high peak seasons. In addition to savings made by the utility, the positive effect on consumers would be a reduction in customer annoyance and higher levels of utility through having a reliable power supply.

We see that consumers tend to reduce their demand for electricity at peak hours while increasing their demand during off-peak hours. This will then decrease the prices during peak hours of the day, but increase the prices during the off-peak hours of the day. We can see that RTP will reduce both price and electricity consumption during peak hours while RTP will increase both price and quantity during off-peak hours - but the realised off-peak price would normally still be less than the average price of electricity.

Figure 3.5 Effects of Demand Response on Wholesale Energy Prices



Referring to Figure 3.5, an increase in the off-peak consumption of electricity might decrease the cost of electricity to consumers in these hours of the year because the long-run marginal cost of electricity is less than the average price of electricity in these hours. So, consumers who do not join in the programme will also benefit from such a programme as demand response in the market reduces the average electricity prices for all grid consumers (Albadi and El-Saadany, 2008; Sezgen *et al.,* 2007). Although this may be true, we believe that the impacts of time-varying prices on electricity bills depend on different consumption patterns on different consumers. Also, the lack of consumers' attention to changing hourly prices might result in increased bills for these customers. Compared to average pricing, dynamic pricing benefits some customers while harming others which brings the issue of equity concerns among consumers into view (e.g. Borenstein, 2004).

In deregulated wholesale electricity markets, especially in peak hours, the price of electricity reflects differences in marginal costs and time-varying differences in firms' abilities to push prices above actual marginal costs by exercising some level of market power[165]. So, the increase in power generation costs are reflected in wholesale prices, but the increase in wholesale prices might be larger than the incremental cost increase if generators exercise some level of market power[166]. Examples of generators exercising market especially during peak hours include, for

[165] By definition, the market power exercise of generators arises when they are able to increase power prices above the competitive price (marginal cost) level – through physical withholding (reducing supply), financing withholding (bidding higher prices) and increasing market concentration (collusions). This also applies to future contracts, for example, if generators tend to reduce their output in a current trading period (t), then the spot prices tend to rise for the next trading interval (t+1) .Under these two circumstances, the system serves at a lower demand but with higher prices. There are policy precautions to prevent market power including structural (for example removing barriers to entry) and regulatory measures (for example price caps and long-term contracts).

[166] Firms might exercise market power in an oligopolistic market. However, in case of deregulated market structure, market power might still exist as long as bid price exceeds marginal cost of electricity generation. Simply put, generators supply bids higher than their marginal costs and strength of anticompetitive behaviors of generators correlated with this gap. There are indices used to measure the market power such as Lerner Index (LI), Elasticity-adjusted Lerner Index (EALI) being a form of price-cost margins, or forms of concentration ratios such as Herfindahl–Hirschman Index (HHI), Comprehensive Concentration Ratio (CCR), and Residual Supply Index (RSI). These types of estimates are very useful when we deal with oligopolistic markets. If data on marginal cost of electricity generation, the price-elasticity of demand for electricity and finally market shares are available, the LI or EALI can be used. Since we usually cannot obtain this kind information accurately (firms may not present their true

example the UK (Green and Newbery, 1992), and the US (Lafferty *et al.,* 2001; Borenstein *et al.,* 2000). Although this is not desirable, suppliers may still exercise market power due to the monitoring and mitigating difficulties encountered by the regulators and competition authorities (Twomey and Neuhoff, 2010), and also due to inexistence of demand elasticity from flat retail prices, for example in the UK (Mansur, 2001), in Germany (Weigt and von Hirschhausen, 2008) and in the US (Borenstein *et.al.,* 2002).

The market power abuse can be reduced by two ways, through the supply side by reducing market concentration or through the demand side by allowing customers to respond to the changing price of electricity. If consumers are unable observe time-varying prices, they cannot limit the price rises so firms have incentives to exercise some market power, particularly during periods when capacity constraint is binding (Borenstein and Holland, 2005)[167]. Dynamic pricing of electricity, however, might dampen wholesale price volatility, reduce the likelihood of market power as if consumers refuse to purchase electricity at high prices, and finally reduce average energy prices to all consumers (Joskow and Wolfram, 2011; Albadi and El-Saadany, 2008; Violette *et al.,* 2007; Borenstein and Holland, 2005; Hunt, 2002; Caves *et al.,* 2000; Moezzi *et al.,* 2004; O'Sheasy, 2003; Braithwait *et al.,* 2002; Faruqui and George; 2002). Application of real-time-pricing ensures competitive wholesale market outcomes in the short-run, for example in the form of lower equilibrium prices (Centolella, 2010; Holland and Mansur, 2008; Zarnikau, 2008; Braithwait *et al.,* 2006; Borenstein and Holland, 2005; Kirschen, 2003; Rosenzweig *et al.,* 2003; Borenstein *et al.,* 2002; Joskow and Kahn, 2002; Brennan, 2002; Borenstein and Bushnell, 1999) and this might also promote a more efficient generation mix in the system in the long-run

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costs), researchers mostly apply HHI to measure market power or RSI. A comprehensive study on market power is available in Newbery, Green, Neuhoff and Twomey (2004). Also, see related studies for shortcomings of pool markets in electricity trading, such as Green (2000).

[167] Although this is true, regulators or competition authorities may allow generators to exercise market power at certain degrees so that they achieve revenue adequacy in their short-run operations (especially high fixed costs plants), and keep investing in generation capacity to maintain the overall system reliability in long-run (Twomey and Neuhoff, 2005).

(Centolella, 2010; Borenstein, 2004; Borenstein, 2005). These authors clearly argue that demand response can restrain prices to their economically efficient levels by promoting the efficient operations of the restructured power markets. A substantial reduction of price can occur when even a small fraction of the load responds to varying electricity prices as displayed in figure 3 above.

The use of dynamic pricing of electricity will also alter the emissions from electricity generation by simply changing the load distribution in the short-run and by changing the power plant mix in the long-run (Gilbraith and Powers, 2012; Friedman, 2011; Allcott, 2011; Holland and Mansur, 2008; 2006; Kiesling, 2002; Hirst and Kirby, 2001). As with the marginal cost of production, power plants also differ in terms of their emission of pollutants per unit of electricity generation. For instance, coal plants are cheaper but more polluting than the thermal plants running with heavy fuel oil[168,169,170]. Old power plants are more polluting plants with very low operating efficiency, which are used only during high demand hours. A reduction in demand for electricity in peak hours could actually reduce the use of these old stations which are expensive to run and dirtier for the environment, and also reduce the requirement for operating reserves in those hours. The short-run effects of marginal cost pricing on the environment is ambiguous, however. The changes in the load factors in peak and off-peak hours will change the capacity mix in the system, so we expect changes in emissions in relative terms, but not in absolute terms. In other words, it may not always be the case that demand response is a useful tool to reduce emissions by reducing the peak power generation that has the potential for poor air quality, as in Australia

[168] For such comparisons, see for example Alcazar-Ortega *et al.,* (2012), Tekiner *et al.,* (2010), Murray (2009, p.78) and Meza *et al.,* (2007).
[169] At the same time, we expect benefits of demand response to drop – at least the price of electricity is likely increase - when a carbon tax is imposed. This is because a carbon tax tends to reduce cost differential between coal burned and oil burned generators, so it impacts the optimal stacking of the generation mix accordingly.
[170] Therefore, we can also raise the question of "whether it is possible that the reduction in the price of electricity causes positive welfare effects that are worse than the willingness to accept these emissions?" People want to pay lower prices at the expense of higher emissions? Or reduction in prices with RTP dominates their willingness to pay to avoid such emissions with flat tariff?

(Wright, 2012). At the same time, emissions might also decrease as RTP may discourage the use of large emitting peak plants, but it will induce the use of cleaner off-peak plants explained by load shifting. Consequently, this again means that environmental consequences of such programmes are unclear[171] and it is hard to generalise about the environmental impacts of demand response.

The impacts on both dispatching and emission levels depends strictly on electricity generation technologies in the system and to what extent do consumers alter their electricity consumption in response to peak vs. off-peak price changes, so environmental implications are not the same for all countries (Wright, 2012; Holland and Mansur, 2008; IEA, 2003). Hence, we have to estimate increases in greenhouse gas emissions from load shifting net of decrease in gas and other pollutant emissions from peak demand reduction. Holland and Mansur (2008) also state that emissions from electricity generation tend to decrease or increase depending on load demand change that affects the mix of thermal system that has to supply this change. For clarification, Holland and Mansur (2006) find that RTP tends to reduce CO_2 emissions whilst tending to increase both SO_2 and NO_x emissions. The reason for this is that the RTP adoption increases the use of coal-fired generation which in turn increases all emissions from "dirty" coal plants. The net change in emissions vary, however. For example, the reduction in emissions from gas-fired generators in the system offset the increased CO_2 emissions from coal-fired generators resulting a net reduction in CO_2 emissions. The SO_2 and NO_x emissions will increase with the RTP adoption, however. The reason is that SO_2 and NO_x emissions per kWh from coal-fired electricity generation is very large compared to gas-fired plants, so the reduction in these emissions from gas-fired generators cannot offset the increased SO_2 and NO_x emissions from coal-fired

171 Similar arguments are available in Wright (2012).

generators[172]. Athough this is true, some authors argue that real-time-pricing yields environmental benefits from re-allocation of conventional plants (Friedman, 2011; Kiesling, 2001; Hirst and Kirby, 2001). Therefore, environmental benefits from implementation of real-time pricing are system specific.

In order to conclude regarding the long-term environmental benefits of the application of the RTP programme, we should critically evaluate the impacts of the RTP programme on future thermal generation mix as well as its impacts on the deployment of renewable technologies. We suspect that the concerns over possible negative environmental impacts of demand response programs might be a serious barrier in the implementation of such programs in some countries. Long-run environmental benefits from demand response, the reduction in both generation and transmission lines also impacts the local environment by preserving land resources for future generations[173]. Therefore, we can conclude that environmental implications such as air pollutant and local emissions from electricity generation from implementing dynamic pricing are ambiguous and increasingly unclear in the long-run.

Transmission and distribution lines might be overloaded during high demand hours, so the possible reduction of electricity demand in those hours might relief for both generation congestion and transmission constraints (IEA, 2003). The reduction in peak demand is highly likely to reduce the potential power outages and power losses from the grid that might occur during high demand hours (Goel *et al.,* 2006, IEA, 2003). Reduction in peak demand and flattening the load curve will help electric utilities to improve overall system performance by means of improved system reliability in a cost-effective way (Centolella, 2010; Earle *et al.,* 2009).

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[172] Various emission with their intensities from different fossil-fuels in the US is presented by the US Department of Energy, see http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf. These emissions vary across power generating units as well as kWh emissions from generators depends on emission intensity of fuel and fuel efficiency of power plants (e.g. how much fuel generator needs to produce 1 kWh of energy).

[173] This non-use value of demand response programs could motivate people to support and join the programme. In addition, they might consume less electricity if they aware of the negative impacts of energy consumption.

Therefore, it will enhance grid-use efficiency by means of greater utilization from existing capacity and improved reliability. When benefits from a more reliable power supply are added, the benefits of demand response programs increase substantially.

System reliability over the long-run needs adequate investments in both generation and transmission lines[174]. Demand for generation capacity and transmission capacity must move together. Peak demand reduction and load shifting towards off-peak periods in the short-run might also avoid or postpone peak capacity investments (running just few hours in a year) in the long-run (Ericson, 2011; Holland and Mansur, 2008; 2006, US Department of Energy, 2006; Borenstein and Holland, 2005), reduce the investments in capacity reserves over time (Andersen *et al.,* 2009; Braithwait *et al.,* 2006), and reduce the cost of expanding transmission and distribution infrastructure (FERC, 2006). Therefore, a real time pricing policy will improve the overall welfare in a country by increasing the efficiency of generation investments in electricity supply (Ericson, 2011; Borenstein, 2005). For instance, Borenstein (2005) calculates long-term benefits from applying hourly electricity pricing and clearly shows that hourly electricity pricing reduces the need for peak capacity in the system in response to an increase in prices during peak hours. Savolainen and Svento (2012, 2013) also prove that even a small response from customers (very inelastic demand) and modest participation in RTP programme tends to reduce equilibrium capacity in the Nordic power market. Therefore, the conclusion is dynamic pricing of electricity might foster system reliability both in short-run and long-run by reducing the demand for capacity at high price hours when the system approaches its full capacity.

[174] In the electricity industry, the system reliability in the short-run refers to a perfect balance of power supply and demand in real time. Before deregulation, public utilities were responsible regarding preserving the short and long-run reliability in its system. In the past years, for example, or consumers were given monetary incentives and if incentives were satisfactory for them, they were willing to lower their electricity consumption during peak times, and shift their consumption to off-peak times (Su and Kirschen, 2009; Hill, 1991). There were other forms of public utility interventions including load shedding and scheduled outages. The primary objective of these traditional methods was to increase the power supply reliability and postponing investments in generation –rather than having efficiency in generation.

The consensus in the literature is that demand side programmes such as RTP facilitate renewable investments and reduces electricity consumption which yields benefits to customers through lower bills and to the environment by fewer emissions[175]. For example, a time-varying price of electricity may allow us to reallocate demand to the times of increased renewable power generation so that the system supports a higher penetration of renewables, for example in the UK (Roscoe and Ault, 2010; Torriti *et al.,* 2009), in Germany (Klobasa, 2010). Given this information, we can argue that incorporating demand responses yields more benefit from renewable electricity that is available during off-peak hours than the static pricing we currently use, as in RTP analysed by Borenstein (2005). Additionally, if renewables such as wind and solar displace fossil fuel fired generation with high emissions of pollutants, then dynamic pricing might yield higher system-wide social welfare from intermittent power sources and contribute to the environment by integrating renewable electricity generation.

When intermittent wind and solar sources are added into systems, the additional reserve requirement represents an extra cost for maintaining reliability and reducing the emission saving benefits from renewable energy sources. The demand response programs might be a panacea for the challenge of integrating large renewable power sources into the grid at lower costs (Milligan and Kirby, 2010), and facilitate intermittent renewables at lower integration costs by reallocating demand to times of increased renewable power generation - thereby inducing better correlation between the renewables electricity output and load demand (Pina *et al.,* 2012; Mohammadi *et al.,* 2011; Grohnheit *et al.,* 2011; Klobasa, 2010; Moura and de Almeida, 2010; Jacobsen and Zvingilaite, 2010; Sioshansi,2010; Sioshansi and Short, 2008; Zibelman and Krapels, 2008;

[175] For example, see customer benefits and carbon dioxide emissions savings from household demand response from 2010 to 2030, empirically estimated for the UK economy by the Brattle Group. The report separates demand response into sub categories such as electricity demand reduction, electricity demand response, gas demand reduction and fuel switching. They estimate that total consumer savings would range from 4310-12350 millions of Pounds and carbon dioxide emission savings would range from 28.3 to 97.5 MT CO_2.

Borenstein, 2008; Spees and Lave, 2007; Denholm and Margolis, 2007)[176], which in turn helps a country in meeting its renewable targets and emission reduction targets at lower system integration costs (Finn, 2011; Grohnheit *et al.,* 2011; Friedman, 2011; Borenstein, 2008; 2012).

Furthermore, demand response reduces back-up costs that possibly eliminate or reduce the problem of reliability associated with renewables, contribute system performance and also contribute to the generation flexibility requirement due to the intermittency characteristics of renewables (Borenstein, 2012; E3G, 2011; De Jonghe, 2011; Hamidi *et al.,* 2008; Strbac, 2008). The reduction in back-up costs might come from standby and balancing reserve capacities saved from existing peaking capacities. Both studies by Sioshansi and Short (2008), and Sioshansi (2010) also show that introducing demand response, for example real-time-pricing, reduces the re-dispatching costs and eliminate loss of load events in the system that might arise from the integration of renewables. Therefore, their precise argument is that demand response programs tend to reduce system costs as well as increase the surplus from renewable sources. Given the fact that electricity generation is subject to rigid short-term capacity constraints, the programme may also contribute to greater reliability by reducing power consumption at peak hours of the day when demand approaches the supply capacity. Based on these studies, we can conclude that operational problems due to intermittent nature of renewables are inevitable, but demand side flexibility from dynamic pricing can be regarded as a hedge against the uncertainty arising from renewable electricity supply.

The distributional impacts of such programmes are complicated (Taylor *et al.,* 2005) and bring the issue of equity into the picture. Whether demand response should be mandatory or optional also raises the issue of fairness and equity. For instance, Borenstein (2012) clearly states that most

[176] For clarification, all studies work on impacts of demand response on wind source of electricity generation with the exception of Denholm and Margolis (2007) and Borenstein (2008). Both studies investigate the impacts of RTP on solar sources.

poor consumers in 'Pacific Gas & Electric and Southern California Edison utilities' benefit from critical peak pricing (CPP) with the exception of low-income consumers when low-income consumers have more peaky demand profile on average than those low consumption consumers with less peaky demand profile. Another problem is that these programs are voluntary programs due to political constraints, but low peak demand and high off-peak demand consumers might join the programme in order to accrue benefits from lower prices – but without paying the individual cost of joining the programme[177]. Thus, the utility either has to bear the entire costs from getting lower electricity revenues at zero costs from these individuals, or utility will pass these revenue losses to its remaining customers in the form of higher fixed tariffs (Train and Mehrez, 1994). But, it is worthwhile to state here that mandatory TOU or RTP programmes may face much resistance from potential losers if they realize that the flat rate is preferable from their perspective. Table 3.1 summarises the key impacts of RTP.

3.4.2 Forms of Demand Response in Electricity Markets

There are two forms of demand response programs in the electricity market, namely price-based demand response and incentive-based demand programs. Incentive-based demand programs such as *interruptible and voluntary load reduction programs* work in a way that consumers reach out to wholesale markets and receive financial returns in exchange for reduction in their consumption during certain hours of the day. Therefore, these programs are applicable during peak hours when the wholesale prices are high and system capacity is highly constrained. The consumers receive money directly from generators equivalent to the difference between the wholesale and retail price of electricity. In the longer term, demand response also includes the implementation of energy efficient programs (i.e. energy efficient home appliances) sponsored by utilities or governments (Greening, 2010). In this research, we will not analyse the incentive-based demand programs or energy efficiency programs.

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[177] The old experiment by Aigner and Ghali (1989) provides the relevant approach directed at time-of-use TOU experiments for residential sector, and also validates this idea.

Table 3.1 Literature Summary of Short-Run and Long-Run Impacts of RTP

	Short-Run	Long-Run
Consumers	• improve price stability by smoothing the demand for energy, so consumer benefit from the demand side programmes. • risk their electricity bill with varying electricity prices opposed to fixed flat retail prices- depending on time-lag in notifying and implementing the RTP prices. • peak time users pay higher prices compared to the fixed price they used to pay, so decrease their consumer surplus from consumption. • off-peak electricity users will pay lower electricity prices, so increase their consumer surplus.	• consumers may tend to purchase more efficient home appliances to lower their electricity bills. • lowers electricity bills from more efficient home appliances and may encourage them to re-adjust their consumption to more peak so there exists ambiguity for consumers in terms of total expenditures on electricity. (possibility of rebound effect) • Fixed retail prices tend to decrease with an increase in RTP participation. • Both participating and non-participating customers will gain higher consumer surplus with an increase in RTP participation

System Infrastructure and Thermal Power Suppliers	• use of peak plants (high MC plants) tends to decrease and generators receive lower prices, so their profits are highly likely drop. • use of off-peak (low MC plants) and intermediate load plants (relatively low MC plants) increase and generators receive higher prices, so profits will increase. • consumers eliminate the possibility of market power exercise by generators – seems a promising option to eliminate possible market abuse by generators.	• more efficient in generation supply mix - better utilization of existing capacity, and greater level of system reliability at lower cost (i.e. less reserve with RTP than without RTP programme) • reduce need for peak capacity, and slow down the investments in new generation capacity especially peak capacity investments and transmission capacity investments (strictly depends on own and cross price demand elasticities, so level of response and actual participation from customers) • total equilibrium capacity might increase or decrease in the L-R with an increase in customer participation in the RTP programme depending on change in demand for capacity, but has no effect on either generators' or retailers' profits.

Renewable Power Suppliers	• higher load factor of off-peak renewable power with higher coincidence with the system load, so minimize the waste of renewable power during off-peak hours. • contribute to system reliability so help the system to overcome the intermittency problem of renewables (at least for wind and solar sources of electricity generation that are both intermittent and non-dispatchable). • off-peak hours of renewables power suppliers will be better-off by receiving higher prices whilst peak hours of renewable power suppliers will be worse-off by selling their output at lower prices.	• encourage renewable power investments with more of off-peak hour availability. • discourage renewable power investments with peak hour availability. • improves system reliability due to smoothing effect on the system load, and achieves greater level of renewable integration in a cost-effective way – rather than increasing just reserves in order to cope with intermittency of renewables.
Environment	• hard to quantify, and impacts strictly depend on effects of demand response on dispatching of 'current' peak vs. off peak generation mix with different levels of emissions. • demand response will likely improve air quality if it reduces the use of peak (polluting diesel and fuel oil) plants and increases the use of more clean off-peak and intermediate load hours (e.g. CCGT).	• expected to fall due to an increase in thermal efficiency of thermal plants, higher efficiency in generation mix in L-R and better utilization of renewable power penetration. • Some emissions from electricity generation might increase; some emissions from electricity generation might decrease.

3.4.3 Price-Based Demand Response Programs (PB-DRPs)

Price-Based Demand response programme (hereafter PB-DRP) is any method that allows end-use customers to observe and respond to the time-varying electricity wholesale prices, so both demand and supply side participants involve in wholesale price-setting of electricity. This way of trading electricity yields the optimum level of benefits for participants in the market (Kirschen and Strbac, 2004). PB-DRPs have potential to offer substantial economic benefits (i.e. cost savings) in the form of improved economic efficiency in wholesale electricity markets. PB-DRP in electricity aims to alter both the time and level of consumption by the end-use customers over time in response to these prices.

These programs pursue three main goals (Braithwait and Eakin, 2002) namely (i) *peak clipping*: reduction in demand for electricity at peak time hours, (ii): *load shifting*: redistribution of electricity demand based on varying electricity prices and (iii) *valley filling*: increase of demand toward low cost of supply hours. That is to say, the objective is to keep the differences between peak and off-peak load as small as possible – it is also evident from an economic point of view that a "flatter" electricity load would be preferred for both short-run operations and long-run investments in the sector (Woo and Greening, 2010) . One clear distinction between PB-DRP and RTP or TOU, is that these programs might decrease or increase the overall electricity consumption, and do not only alone reduce the peak demand (peak clipping), but also substitute the consumption of electricity between periods (load shifting).

There are three demand response options where consumers might potentially modify their consumption decisions (i.e. individual load profiles) in response to price changes - or adjust their electricity consumption according to their willingness to pay for the delivered electricity by receiving price signals. These kinds of demand response programs require the installation of smart meters into their homes which allow them to monitor time-varying prices of electricity[178]. The price-based varying tariff options are namely *time-of-use prices* (TOU), *critical peak pricing* (CPP) and *real time pricing* (RTP). We present the basic characteristics of price based demand side participation in the figure below.

Each of these options captures the variations in electricity costs to a different degree (increasing reward), but at the same time with a different level of risk and variation in price (Faruqui *et al.,* 2010; Sioshansi and Short, 2009. There are two extreme forms of pricing schemes available in the market for electricity which are flat tariff and dynamically changing real-time pricing (RTP) over time. Both time-of-use (TOU) and critical peak pricing (CPP) are static and fall between these two extremes. Real-time pricing (RTP) programme is the purest form of PB-DRP. In RTP, consumers know the wholesale electricity price on a day-ahead or hour-ahead basis. Therefore, RTP is a short-term demand response mechanism that allows consumers to respond time-varying marginal costs in electricity generation. Examples of some successful implementation of such real-time pricing of electricity include for Georgia Power and Niagara Mohawk utilities programme for large industrial customers (Hunt, 2002), to residential customers by Ameron-Illions and Commonwealth Edison utilities in the US , and Ontario utility in Canada (Faruqui and Lessen, 2012).

TOU pricing differs from RTP in the sense that rates are known ex-ante and they are fixed regardless of the out-turn system load. TOU prices are determined in advance (pre-set) and usually reflect daily and seasonal variations in electricity costs. More precisely, TOU rates are

[178] In the United States, Pacific Gas & Electric (PG&E) Utility has been implementing time-of-use rates for residential customers since 1982 and estimates in early 1990s show that 80% of participating customers saved about $ 240 annually (IEA, 2003). As of December 2009, Pacific Gas and Electric customers in Kern Country has experienced about 1,100 complaints from customers out of 4 million customers about installed smart meters. Customers officially complained and write that smart meters did not record their consumption accurately, but it was due to over consumption of electricity during hot months of July said the utility.

designed to reflect expected changes in long-run conditions, and these rates do not reflect either volatility or inherent uncertainty in electricity supply (i.e. cost of power supply). Because of this, one major advantage of TOU compared to RTP is that it is less costly to implement for the utility and consumers can adjust their consumption more easily with dynamically changing RTP. Because prices and periods are set in advance, TOU might not achieve peak load reduction and revenue erosion for the utility when demand realization for electricity is higher than anticipated (e.g. true costs are higher than TOU rates).

CPP pricing differs from both TOU and RTP in the sense that the utility informs customers about critical period hours ahead or days ahead. CPP is in the form of a cost premium that is applied at certain times when demand for power reaches the maximum capacity available in the system such as summer and winter peaking hours[179]. One major advantage of this pricing is that the utility might achieve a substantial reduction in peak demand when that has the greatest value to the system and gives an incentive to people to cut their electricity during critical peak times, shift electricity consumption from peak to off-peak hours when critical peak events occur (Wolak, 2010; Herter, 2007). One major disadvantage of CPP for the utility is that it applies only for limited hours (e.g. super peak hours) so the utility must pick the right hours, and a major disadvantage for consumers is that they are able to save only during very high price hours of the year if they respond to the utility's call. Therefore, there is an uncertainty for both the utility and consumers with respect to the occurrence of these hours such that both parties do not know these critical peak price hours. It is very crucial for the utility to pick up these critical hours and

[179] There is also peak time rebate that is similar to CPP. In theory, both CPP and PTR have the same goal; reducing the load when it is very costly to serve peak hours. In practice, consumers with PTR get credits from load reduction during peak hours, but are not punished if load demand during these hours increases. Examples of pilot programs for PTR include the City of Anaheim Public Utility, for residential customers from June 2005 to October 2005. Therefore, there is a safeguard for the PTR participating consumers. It is estimated that CPP pricing in France since 1996 resulted in a substantial reduction in energy demand – such that doubling of peak prices results in load reductions of up to 20%, clearly stated by the IEA (2003).In France, CPP includes three types of days: least expensive days (blue), moderately expensive days (white) and most expensive days(red) and off-peak prices vary from 4.64 euro cents/kWh to 17.62 euro cents/kWh during off-peak hours of these days whilst peak prices vary from 5.77 euro cents/kWh to 49.29 euro cents/ kWh in these days (Giraud, 2004).

this is challenging for the utility.

In demand response programs, there exists a trade-off between risk to consumer and reward to consumer. Among the price-responsive options available, RTP is the most dynamic tariff programme. It captures the variations in electricity costs (plus a small adder or mark-up) based on actual demand and supply balance, and transmission costs. Hence, from an economic perspective, RTP must yield the highest economic benefits only if consumers are able respond to these prices[180]. The highest bill instability to consumers is also from RTP. By risk and uncertainty, we mean that the time when these prices are in effect is unknown. In TOU pricing, consumers pay different prices at different times of the day such that on-peak prices are higher and off-peak prices are lower than the original flat rate. Therefore, TOU pricing reflects the average marginal cost of power supplying each block of hours. So, TOU falls somewhere between RTP and flat rate such that it incurs lower bill instability for consumers and lower revenue instability for the utility as well. Therefore, TOU is less dynamic so that it neither produces full allocative efficiency in the short run nor efficiency of capacity investments in the long run. Finally, we expect CPP to be between TOU and RTP. CPP is a very special form of dynamic pricing, because the utility can chose limited hours to apply CPP. These limited hours are defined as critical hours on event days. The price of electricity is much higher in these certain hours, but prices are lower in off-peak hours than the original flat rate. Thus, the utility has to choose the right hours when demand reaches its super peaks otherwise the utility cannot capture the potential gains from CPP.

Although RTP (dynamic pricing) is more efficient and captures greater variations in marginal cost of electricity, TOU (static pricing) has been more widely used and accepted in countries as it is easier and less costly to implement than RTP (Faruqui and Sergici, 2010; Abrate, 2003)[181]. TOU

[180] See for example, Li and Flynn (2006).
[181] Implementation of advance meeting technology is not difficult in Cyprus; see Advanced Metering Infrastructure in CSE countries – current implementation status, plans, and perspectives, Ernst and Young, June 2012.

rates for residential customers in Pacific Gas & Electric (PG&E) utility and CPP pricing in Electricité de France (EDF) utility are known worldwide as successful demand response programs (IEA, 2003; Aubin, 1995). Borenstein *et al.,* (2001) also argue that CPP pricing is more suitable for small and medium scale residential and commercial consumers as a result of which we get the benefits of RTP with lower cost (implementing CPP is less costly) with a high response (CPP typically applies to 50-200 hours of the year) from these customers. Celebi and Fuller (2007) also suggest that TOU pricing would be more appropriate than RTP for consumers and TOU prices will solve the inefficiency problems from single pricing.

The empirical literature reveals that customers are able and willing to respond to price signals, but the degree of responsiveness varies widely across users. It is no easy task to measure these elasticities accurately for each of these demand response programs (TOU and RTP), because demand response programs must undertake to examine both overall price responsiveness of consumers (program participants) as well as their responsiveness to shift their demand for electricity to off-peak hours. Thus, responsiveness behaviour itself is complex and the elasticities might depend on many factors such as target population with different level of age, house ownership (e.g. with and without insulation, detached vs. semidetached, with and without pool), income, lifestyle (e.g. rural vs. urban), occupation, education level of voluntary participants, sensitivity to environmental problems, and more broadly the way prices are communicated to program participants (how often prices change), rate design, duration of voluntary programs (e.g. seasons included in the experiment), information before they actually voluntarily join the program (e.g. Thorsnes *et al.,* 2012; Taylor, 2005; Reiss and White, 2005; King *et al.,* 2003; Kohler and Mitchell,1984)[182].

[182] These statements are valid for both TOU and RTP experiments, for example Taylor (2005) for both RTP and TOU experiments, and Thorsnes *et al.,* (2012) for TOU experiment.

Consumers' response to price changes is different for each of these programmes because consumers receive price signals at different frequencies (intervals) for each of these programmes. Hence, we expect elasticities to be different for each type of demand participation programme and across users (Patrick and Wolak, 2001). Among these demand response programmes, there is much more certainty about rates and their times of occurrence in case of TOU programmes in comparison to RTP. Hence, the implementation of a TOU programme is easier for system operators, and it is simple for consumers to understand and respond to such a pricing programme.

3.4.4 Challenges and Obstacles for Incorporating Demand Response Programs

Social and political reasons are the main obstacles to moving away from average pricing of electricity, something which we will discuss in later sections. We first however need to clarify these regulatory, technical, economic, political and other barriers and then find ways to overcome them in order to boost demand response in electricity markets. The issue is then the best way of transferring hourly electricity prices to consumers in order to capture the variations in the wholesale price through available demand side participation programmes. The lack of a direct connection between wholesale and retail markets can be seen as a regulatory barrier that needs to be resolved.

The first problem relates to technology and infrastructure that allows consumers to modify their consumption with respect to changing wholesale prices. Meters and control systems allow communication between consumers and electricity retailers and coordinate retail and wholesale markets so that consumers can receive signals of dynamic wholesale price movements. These systems are required for all types of dynamic pricing rates and imply costs for demand response programs. But lack of advanced metering infrastructure is still a serious barrier facing price-responsive demand programs (Chao, 2011; Strbac, 2008).

Table 3.2 RTP Elasticity Estimates Based on Voluntary Programmes

Author(s)	**Model and Data**	**Main Findings**
Harriges *et al.,* (1993)	Nested CES Niagara Mohawk Power, data from 9 participating large industrial customers with peak usage greater than 2,820 kW, and 6 control group facing TOU pricing with peak usage exceeding 2,940 kW. Metering Interval: day ahead hourly prices, hourly data is from April to November 199X.	The response to RTP experiment is not uniform among participating firms and seasons (months) Intraday elasticity of substitution estimates vary between 0.085 to 0.136 Inter-day elasticity of substitution estimates vary between 0.073 to 0.560 Approximate pool average intra-day and inter-day elasticities of substitution are 0.093 and 0.163, respectively, so elasticity of substitution across days is almost twice as larger than the substitution of elasticity within days.
Patrick and Wolak (2001)	Symmetric Generalized McFadden Cost Function[183]. UK Midland Electricity Market, data from 520 medium and large scale commercial and industrial customers with load demand exceeding 100 kW, and at the same time peak demand being greater than 1,000 kW. Metering Interval: day ahead half-hourly prices, from 1991 to 1995	Heterogeneity across industrial customers such that elasticity estimates reported vary across industries. Water supply industry is highly responsive with own price-elasticity ranging from -0.01 to -0.27, but hourly elasticity is estimates for other sectors range from 0 to -0.05.
Schwarz *et al.,* (2002)	Nested CES Duke Power, data from 110 large scale customers from 20 different sector Metering is day-ahead, from June to September months, 1994-1999 to 1999	Higher response from industries with onsite generation facilities, and those industries affected from power interruptions. Reduction in load during high price hours that is independent from elasticity estimates as prices during hot summer peak period vary 5 to 10 times.

[183] Different from CES, in this particular methodology, electricity demands throughout the day can be treated as substitutes and complements across different hours of the day.

Braithwaith and O'Sheasy (2002)	Georgia Power, USA, data from 1600 medium and large scale commercial and industrial customer with load demand greater than 200 kW.	Own-price elasticity estimates vary across customers, as well as changing hourly price levels. Elasticities are ranging from -0.01 to -0.28.
Boisvert *et al.,* (2004)	Generalized Leontief (GL) Model Central and Southwest Services, data from 54 large scale commercial and industrial customer with load demand greater than 1000 kw. Metering Interval: Two-part RTP tariffs, one customer segment with day-ahead option and another customer segment with hour ahead pricing options, years of study between 1998 and 2001	Elasticity of substitution range across customer segments and classification of the peak period. The elasticity of substitution from day-ahead RTP customers ranging from 0.10 to 0.18 with an average substitution of 0.14 The elasticity of substitution from hour-ahead RTP customers ranging from 0.20 to 0.27 with an average substitution of 0.235
Taylor *et al.,* (2005)	Symmetric Generalized McFadden functional form Duke Power, data from 51 large scale commercial and industrial customers, with load demand greater than 1,000 kW. Metering Interval: Two-part RTP, with day-ahead hourly price notification, June, July, August, and September summer months data during 2001.	Elasticity estimates vary over day and across customers. Higher response to price change occurs during high price peak hours and peak energy substitution is not for next or one earlier hour (i.e. 8pm-12am peak energy is substituted for potential 2pm-6pm peak hours). Higher response from industries with onsite generation or furnace oil such that own-elasticity increase from -0.029 to -0.269 with onsite generation facilities. Elasticity increase with each additional year of RTP experience.
Boisvert *et al.,* (2007)	Generalized Leontief (GL) Model Central and Southwest Services, data from 119 large scale commercial and industrial customers with load greater than 1,000 kW. Customers are divided into two segments, one group is notified in day-ahead pricing, and another group of customers are notified hour-ahead pricing, hourly price and load date is from 2000 to 2004.	Load weighted average elasticity of substitution is modest at 0.11. About 75% of the aggregate prices is concentrated in the 18% of customers with the highest elasticity of substitution estimates. Manufacturing customers are the most price responsive customers, followed by government/education, and finally commercial/retail customers.

Note that the cost of implementing the price response program varies, for example a billing engine is must for all programs, but pricing engine software is required for only RTP, not for TOU or CPP (Pratt, 2011, p.10). Although some argue that the capital costs of installing advanced metering equipment into homes are high (Torriti *et al.,* 2009), costs are falling due to technological progress (Hirst, 2002).

Despite the fact that metering costs are falling over-time, it is argued that small consumer gains may not repay the gross costs of such installations and equipment (Alcott, 2011; Costello, 2004; Borenstein, 2001; Aigner, 1984), but it would be desirable to make them mandatory for large users of electricity (Borenstein, 2001). Some authors also find that the overall welfare implications are large enough to compensate for these costs (Borenstein *et al.,* 2002a; Borenstein, 2007). Another problem arises with ownership of such meters: who must bear the cost of installing these devices to allow communication between retailers and customers (O'Sheasy, 2002)? Consumers are free to choose their suppliers (retailers), and can change their supplier at short notice. This might discourage retailers to install these devices

In the past years, we were unable to charge prices hour by hour due to technology constraints, but this problem seems now to be disappearing. But it is not only metering cost, but also costs of program design, marketing the program, implementing the programme, educating the people, billing and customer services, technical assistance to customers are also part of the program costs. These are large infrastructure investments. Yet, these costs are still an obstacle for the implementation of demand response programs and reasons for their slow penetration[184]. But with falling costs, and as result of an increasing number of households and commercial customers equipped with smart metering (as well as intelligent appliances), they will be given an opportunity to face time-based electricity prices.

[184] Based on utilities' experience, these problems are clearly stated. For details, see Barbose *et al.,* (2004).

Installation of smart meters, and letting end-use customers react retail prices is not enough to guarantee that we will have high response from customers. Retailers purchase from wholesale markets, but end-use customers purchase their electricity at retailers' prices. In practical terms, retailers charge for electricity, including an insurance premium as well as fixed expenses such as grid payments and taxes. Two main problems arise in this fixed retail pricing. First, these fixed costs are charged regardless of their consumption level – they do not depend on the consumption level. Therefore, the larger these adders, the less incentive is given to end-use customers to change their electricity consumption (Grohnheit *et al.,* 2011, Andersen *et al.,* 2009)[185,186]. Although this is a reasonable and valid argument, retailers need to charge these fixed fees in order to cover their costs. The second potential problem is the insurance premium retailers charge in order to secure their revenues from price risks. A potential problem is who will share the risks arising from time-varying price of electricity – what is the distribution of these risks between customers and retailers (O'Sheasy, 2003; Boisvert *et al.,* 2002)?

The cost-benefit analysis of such programmes are different across users, for example, costs exceed benefits for small consumers (Borenstein, 2001) while benefits exceed costs for large industrial customers (Borenstein, 2001; Herriges *et al.,* 1993)[187]. Whether hourly metering is cost effective or not depends on the proportion of metering costs over the total electricity bill (calculated from retail prices, not wholesale price) which consumers pay. Therefore, consumers prefer their billing based on an average price until metering costs come down. Note that the metering is likely to be cost effective for large industrial users because metering costs are small compared to their electricity bills. Based on this continuing disagreement about the cost-

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[185] The fraction of these additives in our country of study, Cyprus, is the smallest among all other EU countries.

[186] For details, see for example the RESPOND Project (2006-2009) by Andersen *et al.,* (2009).

[187] The benefits and costs of this programmes for a particular sector depends on their willingness and ability to respond the prices. In this regard, large businesses seem react changes. Estimates from Australia also show that elasticities of large industries are much higher than those of residential customers (NEMMCO, 2006). Therefore, attracting large users might be a first step toward this programme, as authors listed above also suggest.

effectiveness of demand response programs, we can verify that there is no standard checklist for benefits and costs that must be included in the analysis. The choice of time-horizon in the cost-effectiveness analysis is crucial and changes the numbers radically. To illustrate, it is easier to screen and capture the financial costs of the programme, and they are mostly accrued in current years. But economic benefits are manifold and distributed over a longer time period.

The second important issue is the widespread application of fixed uniform retail prices and consumers becoming accustomed to these fixed retail rates. End-use consumers are willing to sign fixed contracts voluntarily, because a fixed retail contract ensures more stable and predictable prices, and hence bills. With time-varying electricity prices, what consumers pay for electricity will fluctuate with the wholesales cost of electricity. These price fluctuations are not currently reflected in electricity bills This fixed retail price discourages these customers to respond to these fluctuating (dynamic) pricing in these markets (Faruqui and George, 2002; Hirst, 2002). We assume that consumers can monitor time-varying prices of electricity and adjust their consumption accordingly, but this monitoring is not costless. Joskow and Tirole (2004) state that cost of monitoring time-varying prices (in this case RTP) and adjusting the use of home appliances for small consumers is very high implying that they do not pay attention to the price changes and consequently do not adjust their consumption patterns accordingly. This is another major obstacle to implementing time-varying electricity prices. But, the use of more sophisticated computers in appliances might potentially solve this problem so consumers do not need to monitor the changes in electricity prices.

In addition, the barriers to implementation and consumer acceptance include risks, welfare transfers and mandatory versus voluntary programs (Borenstein, 2007b; 2003). These barriers cause a debate whether demand response programs to should be voluntary rather than mandatory for all types of customers. The critical question would then be: is a demand response program

(RTP or TOU) transparent and fair for the market participants or not? Consumers are heterogeneous in terms of electricity consumption. For instance, the residential consumers' demand for electricity at particular hours of the day differs from that of industrial and commercial users. The implementation of demand response in practice is more complex than anticipated when the issues of customer price risk (volatile bills) and equity concerns are taken into consideration (Borenstein, 2003; Borenstein, 2011a). Faruqui *et al.,* (2010) and Faruqui and George (2005) find that there is a significant reduction in demand during peak demand with TOU pricing, but they also show that reductions vary between different types of consumers.

Given the impacts of RTP pricing (for example see figures 4 and 5), consumers with smoother consumption patterns will win from such programmes, but consumers with a more peaky demand will not be willing to switch to RTP pricing as they will pay more than with a flat rate. This will create debate whether the implementation of these programs should be voluntary or mandatory, clearly stated by Borenstein (2007a and 2007b). In fact, these changes in gains and losses are welfare transfers within consumers and between consumers and producers. Borenstein (2007b) also argues that political barriers are a serious problem, for example when real-time pricing increases the electricity bills of customers who pay less than average pricing. Given this fact, wealth transfers from dynamic pricing also causes social as well as political barriers in the implementation of time-varying electricity prices.

The risk of volatility and uncertainty in electricity bills due to changing prices (Faruqui and Sergici, 2009; Borenstein *et al.,* 2002a; Faruqui and George, 2002), a complex billing structure of dynamic pricing for retail customers (Joskow, 2010), and possible profit losses for generators from the RTP programme (Holland and Mansur, 2006) is used to justify the application of average pricing in the electricity supply industry[188]. To sum up, these issues are more related to public acceptance and distributional effects that reduce the incentives for RTP or other forms of dynamic pricing to be implemented. Every consumer is concerned about the volatility of electricity prices and so might ask for some forms of hedged service from their supplier (Barbose and Goldman, 2004). At the same time, deregulation of electricity industries transfers risk for retailers because they must purchase electricity from generators in spot markets at volatile prices - but sell their electricity to consumers at fixed retail prices. What this means is that the disconnect between these two markets creates revenue risks for the retailers in the deregulated electricity markets.

The most simple risk mitigating measure is hedging against uncertain future prices so that the overall volatility in the electricity bill reduces (Faria and Vale, 2011; Borenstein, 2007b; Borenstein 2006; Costello, 2004; Borenstein, 2003; Hunt, 2002; Hirst, 2001a). Based on their expectation about future prices, consumers can sign long-term purchase contracts for certain blocks of their electricity demand at a fixed price based on their historical consumption and join the spot market for the residual demand they consume (e.g. two-part RTP). Utilities then provide a menu of electricity pricing for its customers that is composed of spot and in advance contract prices. In this way, utilities (i) create incentives to consumers to join and respond to the price changes, (ii) maintain the incentives in generation investments over the long-term, and (iii) avoid the problem of possible market power exercised by generators. Therefore, the risk of volatility in the electricity bill is no reason for not implementing the demand response programs according to these studies. In addition to this, there are other important factors that affect customers' decisions. For example, customers with a high elasticity of demand and a large divergence

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188 Note that the severity of these problems differs across the demand participation programs, such as TOU, CPP and RTP programs. The risks for consumers and loss of profits for supplier depend entirely on the frequency of dynamic pricing being applied – that is different between these programs. For instance, Faruqui and George (2004) investigate the impacts of TOU on customers and utilities. They also point out similar problems, but for public utility owned electricity systems.

between hourly prices and average price could be encouraged to move away from average pricing.

We already stated that these types of programmes are voluntary at the moment, but the political risk of implementing voluntary programs exists. Especially, some argue that people are not willing to adjust their consumption in response to changing electricity prices, so they end up paying higher retail prices if they shift away from flat electricity tariffs (Wolak, 2010). This can be linked to cultural beliefs and lack of public knowledge (or education) about the benefits of dynamic pricing of electricity (Zarnikau, 2008; Goldman, 2005; Hirst, 2002). Customers have little knowledge about billing and there is a lack of understanding for potential welfare impacts of such programmes (Kim and Shcerbakova, 2011). Therefore, utilities and other legal entities are responsible for showing the opportunities for customers to realize bill savings from participation in the programme. Electric utilities, regulators and policymakers have a critical responsibility in this matter because they are responsible for marketing these types of programs. If they market these programs effectively, customers would have information about their benefits.

Customers may not understand all of the terms and conditions of the power purchase contract that is offered by the retailers and might not be able to compare the impacts of fixed prices vs. time-varying prices on their bills (Dewees, 2001). It is worth stating that poor marketing of the programme and limited technical assistance provided to help participants in managing their price volatility are the main reasons for low participation and penetration of these programmes, based on a comprehensive survey of utility experience in the US (Barbose *et al.,* 2004). The volatility in electricity prices and complexity of billing for electricity consumption was one of the reasons why residential and commercial customers are given less priority in implementing these programs relative to industrial customers (Allcott, 2011). Most consumers have a misconception that volatility of prices translates into a higher electricity bills and this in itself can present a barrier

(Hirst, 2001b)[189]. On a small scale, individual utilities can even start moving their customers to time-varying prices which will improve the participation rate (Faruqui *et al.,* 2010).

In order to decide whether the particular programme is worthwhile to implement, or postpone depends on cost-benefit analysis. For the adoption of dynamic pricing in any country, we first need to estimate the benefits of such programs individually and then the cost of upgrading all residential meters as well as the cost of advance metering infrastructure. The selection and quantification of benefits and costs determines the benefit/cost ratio of such programs and (Greening, 2010; Nichols, 1995). This is a serious problem because, the share of customers adopting demand response programs clearly depends on market conditions, customers' information, and marketing of the programs and high participation is necessary in order for these programs to be cost effective. That is why the economic viability of demand-side participation has to be evaluated carefully.

The argument is then that the consumers' response to price changes becomes essential in order to achieve greater value from increasing renewable deployment in a power generation mix. This is not true for all renewables as we will discuss in later sections, but we can now say those impacts of demand response programs, for example RTP programmes, are not technology-neutral across thermal as well as renewable generators. The final note on the supply side is that demand response programmes together with renewables may also mitigate a risk of electricity price increases due to possible fuel price increases for thermal plants. To sum up, renewables may lead to higher levels of social welfare than we anticipate if we incorporate price responsive demand into the power markets, and also help countries to comply with their national targets for renewables in their electricity production.

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[189] For details, see Hirst, E. (2001), Price-Responsive Demand in Wholesale Markets: Why Is So Little Happening? *The Electricity Journal,* 14(4): 25-37.

Finally, the supply side effects are also complicated as we should not expect the demand response programs to be neutral across different types of power plants. RTP will change the demand and so the dispatch of power plants. For instance, some thermal power suppliers may lose their profits (especially peak thermal) due to the RTP programme, such as in Spain (Torriti *et al.,* 2010). The possible potential problems are[190]: compensating for the losses of 'generators' if incurred, the choice of the right electricity price so that they get a high enough rate of return on their invested capital, the possibility of generators attempting to charge prices that deviate from actual marginal cost per kWh, and higher electricity rates for the revenue losses from non-participating customers or participating customers, or equally from all customers.

3.5 Electricity Pricing in Cyprus

The electricity market in Cyprus is not liberalised and is dominated by a public utility. It has closed household retail markets, and competition is non-existent due to the single supplier. The Electricity Authority of Cyprus (EAC) is the responsible institution for price-setting (i.e. regulated prices) and billing of electricity in Cyprus and charges different rates for domestic, industrial and commercial users[191]. Electricity prices in Cyprus are indexed to fuel oil prices with a fuel adjustment factor, so changes in fuel prices are reflected in consumers' electricity bills[192]. Residential consumers choose their electricity tariff based on their individual daily consumption profile (i.e. whether they are at home during the daytime or during the night-time). Commercial and industrial customers choose depending on their load size and on their grid supply voltage. In terms of billing, domestic and small commercial and industrial users (with meters connected to high or medium voltage) pay their bills bi-monthly while large commercial and industrial consumers pay their bills on a monthly basis. They mostly receive their electricity bill by post.

[190] See Salies (2013).
[191] Cyprus Ministry of Commerce, Industry and Tourism is the responsible institution for competition policy and energy policies of the country, not the EAC.
[192] Fuel price changes and fuel price adjustments are available at EAC see:
https://www.eac.com.cy/EN/CustomerService/Tariffs/Documents/AverageFuelPrice_2013eng.pdf

Retail electricity prices without tax or fixed adders in Cyprus are currently very high, so much so that they are the highest in the EU at an average rate of 0.20 euros per kilowatt-hour as of 2012 (Eurostat, *Energy Price Statistics*, 2012). At this rate, consumers pay 26% more than the average EU citizen pays for his/her electricity consumption. Zachariades and Pashourtidou (2007) use time series data from 1960 to 2004 to estimate both short-run and long-run price elasticities for electricity demand with an error correction model. They show that short-term elasticity for electricity is not significantly different from zero, but long-run elasticity ranges between -0.3 and -0.4. They did not separate the demand for electricity into different load levels.

The billing of electricity consumption is made via old meters for existing connections and new meters for new connections to the national grid. As of 2012, both old type electromechanical meters and electronic meters for new generations are currently in use in Cyprus. The major advantage of new electronic meters is the high and consistent accuracy of electricity consumption compared to old type meters. New electronic meters are not smart meters however, and so no meters used in Cyprus record electricity usage by the hour and no real-time price information reaches consumers.

It is cheap and quick to install these meters, but they have some disadvantages over smart meters. These disadvantages include the high labour cost of meter-reading, lack of information about the consumption profile as it gives cumulative consumption over billing period, and finally their inability to send time-related price signals to consumers. In order to overcome these problems and capture the benefits of time-varying electricity prices, installations of smart meters into home and efficient system of communication between utility and consumers are mandatory. Even though smart meters are more expensive than traditional meters, their costs are falling sharply over time. Therefore, we expect that smart meters will quickly replace the old-type traditional metering devices used for measuring domestic electricity consumption, especially for residential and commercial customers for whom it is not cost-effective yet (Hesser and Suucar, 2012; Torriti *et al.,* 2010). In Figure 3.6 below, we present the demand pattern for electricity in Cyprus. Based on this figure, we clearly see that peak demand hours are morning and night whilst off-peak demand hours are at mid-night. Within these hours, the system approaches its available capacity during the summer month of the year while only half of the generation capacity operates during the winter months[193]. Demand for electricity by households has increased substantially (see Figure 3.7) due to increasing number of home electric appliances and air conditioning units (because of hot weather A/C is run on a frequent basis during summer months of the year) and electric water heating during winter. This is due to the Mediterranean climate giving hot and dry summers, and mild winters.

The economic sustainability of small islands heavily depends on the service sector mainly due to the lack of physical resources. In Cyprus, tourism is the main source of revenue from such services. There is a massive influx of people onto the island for short-term visits. The increase in the temporary population during the summer months is translated into the additional demand for electricity as reflected in the data used in this paper. Tourism statistics of the Cyprus show that even though the number of tourist arrivals dropped in the period 1999-2010, CIE (2012) shows that electricity intensity of hotels and restaurants branch has increased from 393 KWh/€ (2005) to 560 KWh/€ (2005) in the same period. This might be due to high use of AC and construction of new touristic buildings (expansion of sector) as stated in the same report.

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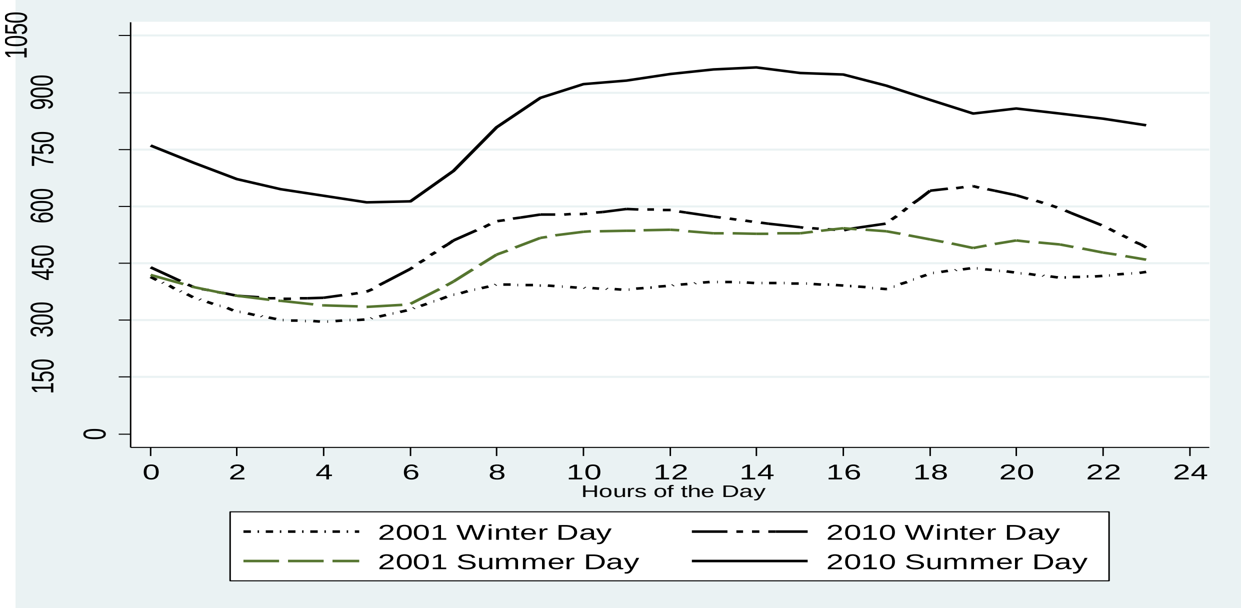
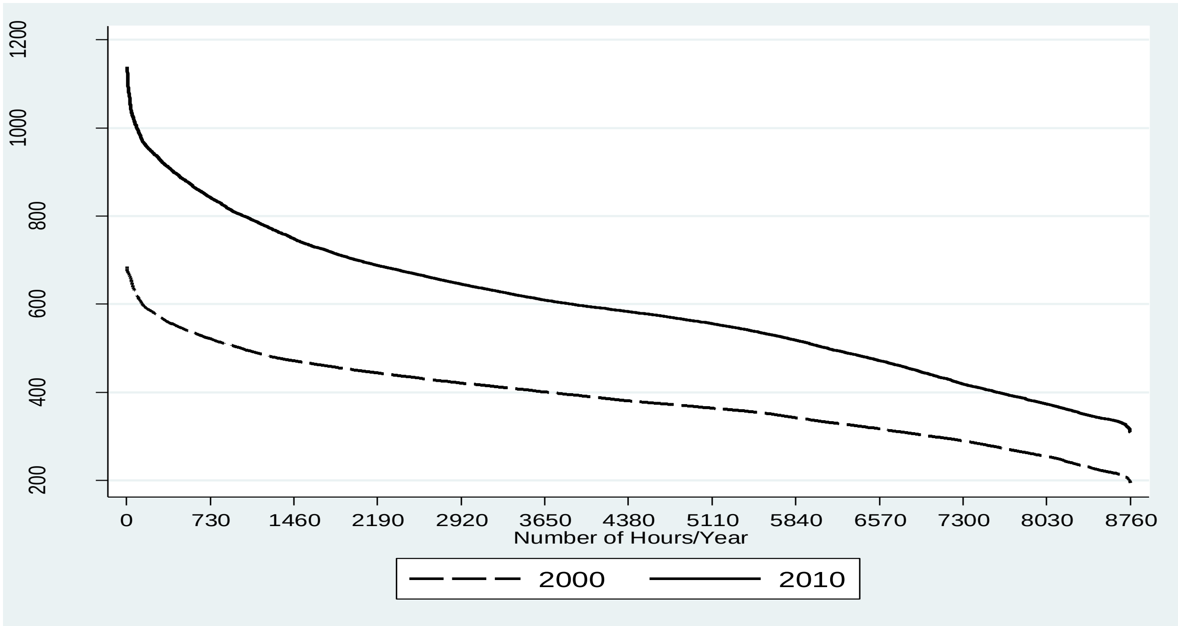
[193] Higher temperatures may raise or lower the electricity demand – one peak in summer, and one peak in winter. Expected relationships between temperature levels and demand for electricity is as follows: There is a strong positive correlation between load consumption and an increase in temperature (possibly also humidity) whilst negative correlation between load consumption and a decreasing temperature. A seasonal model might be applied to isolate differences between summer demand patterns from winter demand pattern.

Figure 3.6 Typical Daily Load in Cyprus – Winter and Summer Days in 2000 and 2010



Source: Based on data available in web, supplied by Transmission System Operator, Republic of Cyprus

Figure 3.7 Peak and Off-Peak Capacity Growth in Cyprus between 2000 and 2010



Source: Based on data available in web, supplied by Transmission System Operator, Republic of Cyprus

The demand for electricity has time-dependent characteristics. Based on the figure above, demand for electricity follows both diurnal and seasonal changes in Cyprus. Thus, electricity at midnight in February is completely different from electricity at noon on a hot July and August afternoon[194]. Dispatching of power plants must follow the same pattern so that demand equals supply at all hours of the day and during all seasons of the year. As opposed to the thermal power supply, electricity generation from wind and solar sources differs during different hours of the day (e.g. more wind at mid-night and more sun during day time hours) as well as differing across the seasons (e.g. more wind during winter, more sun during the summer months) (Koroneos *et al.,* 2005). Hence, electricity generation from renewable sources also follows both diurnal and seasonal changes in Cyprus.

The key reason to identify the load demand is to select the right target population to implement an appropriate demand response program. In other words, the aim is try to find major contributors to summer peak demand and the critical question is whether these customers would actually use less electricity at these times if the utility charged them more.[195] To illustrate it another way, as the primary aim is to reduce summer peak use of electricity in Cyprus, the appropriate focus group would be households with air conditioning. A detailed analysis of demand would be strictly necessary in the assessment of the potential demand response in any country. In the figure below, we clearly see that the demand for electric capacity is above 85% for about 2% of the time. In other words, 98% of the time, only 85% of capacity is used. The lack of price responsiveness during peak periods has been a major concern to utilities as demand for electricity and cost of supplying tend to concentrate in these peak hours.

194 Based on need of electricity from weather conditions, we can expect that elasticities might vary seasonally.
195 For example see Faruqui and Sergici (2009).

Based on the figure above, we expect growing load factors in winter and summer peaks in Cyprus and this will create serious problem in the Cypriot electricity system. This is because these growth rates have led to the extensive use of peaking load plants continuously, causing higher costs for the whole power system in Cyprus under the current pricing regime. Therefore, we can suggest that consumers in Cyprus need to be motivated to reduce their energy consumption during peak hours when capacity is becoming stretched.

In Cyprus, old power plants are more polluting with a very low operating efficiency, and are used only during high demand hours. Reducing the demand for electricity in peak hours could actually reduce the use of these old, expensive to run, and highly polluting plants. Note that these peaking plants are needed to meet a very small number of hours of peak demand each year with relatively high operating costs relative to capital costs. If this happens, the electric utility in Cyprus can avoid the capital cost of this extra generation, achieve a higher level of utilisation of existing generation capacity and reduce the environmental harms visited on society in Cyprus. This is necessary from the investment efficiency point of view: simply shifting electricity consumption away from peak periods provides many potential efficiency benefits for the economy.

Table 3.3: Fixed and Variable Cost Characteristics of Supply System in Cyprus in 2010

Type of Load	**Annualized Capital Charges ($/MW)**[196]	**Fuel Consumption (kg/MWh)**	**Emission Intensity (kg/kWh)**	**Total MC (Euro/MWh)**[197]
Peak	43,180	0.210	1.072	178.10
Mid-Merit	67,854	0.285	0.855	138.55
Off-Peak	135,708	0.357	0.683	109.26

Source: Poullikkas and Kellas (2004, p. 526)

[196] Social discount rate of 8% is used in the calculation of annualized fixed cost.
[197] Variable cost components accounted in the generation dispatch include fuel cost, variable operating and maintenance costs and emission costs.

Based on approval of the renewable projects in Cyprus, we can say that wind power investments represent a strongly increasing percentage of overall renewable electricity production, but the problem with wind is that it does not normally does not follow the typical demand profile. In other words, wind mostly blows at low-price hours. So, additional peak plants (standby reserves) are required for grid flexibility with wind power. Hence, demand response programs seem to be necessary to reduce prospective peak investments and use of existing peaking plants to maintain grid flexibility is required with a high penetration of electricity from wind. Unlike wind, solar power is available during high-price hours of the year.

3.6. Simulation Model

3.6.1 Model Assumptions and Data Description for Simulations

The aim of this paper is to study whether the use of real-time pricing can increase efficiency in the electric industry and reduce the cost of integrating renewables generators. Therefore, we analyse the impacts of real-time electricity pricing (i.e. marginal cost pricing for end consumers) in the Cypriot electricity market on power prices, peak and off-peak capacities, emissions from electricity generation, welfare change, and renewable energy sources such as wind and solar. Although wholesale markets have been open to competition during the deregulation of many electric utilities in Europe, most end-use customers still pay fixed regulated retail prices for their consumption that do not vary with the time of day or level of demand. We use a merit order stack approach to generation investment and operation decisions. Effectively, a system planner minimises the total cost of capacity and output – this produces equivalent results to those that an efficient competitive market would give. The system planner will have to charge a set of prices for RTP-participating customers and a single price to non-participating customers in order to cover the cost of supply. We apply the the model developed by Borenstein (2005) and Holland and Borenstein (2005), so we also model consumers' demand with a constant elasticity function. We compare the impacts of time-varying pricing on load profile by splitting customers into two:

those who pay their electricity bills with time-varying prices and those with flat-rate electricity prices. We apply the model to a real electricity market using real (hourly) market data for Cyprus.

Three types of conventional power station are modelled, representing peak, mid-merit, and baseload generators. The model includes wind and solar generators as the two kinds of renewable power most suitable for Cyprus. The generation specific data is presented in the table below. Based on approval of the renewable projects in Cyprus, we can say that wind power investments represent a strongly increasing percentage of overall renewable electricity production. Therefore, we include wind only in order to see the potential impacts of real-time pricing on the system with wind power. The model, however, can provide results with a mix of wind and solar. Due to confidentiality of data, capital and variable cost data of generation technologies only approximates the production cost structure of the Cypriot electricity system. In our simulations, we chose the shape of the 2010 annual load duration curve[198]. The reasons to choose the 2010 annual load duration curve are the system deterioration from July 2011 caused by the explosion at Vasilakos power plant and the unavailability of the 2013 annual load duration curve. The simulation results are very sensitive to supply and demand characteristics of the system. Therefore, fully accurate generation level data might produce slightly different results than shown here.

Before proceeding with the model, we summarize the following assumptions that clearly set the boundaries of the equilibrium models. In the implementation of dynamic rates, first we assume that a two-way price communication mechanism (and infrastructure) between retailers and consumers exists. We assume that all electricity consumers (residential, commercial and industrial) have meters to observe the changes in electricity costs (price) and so can interact with the supplier. The system operator is assumed to operate and implement the programme, so the

[198] This means that we take 24 hours x 365 days in a year, so total of 8760 hours of the year.

system operator can anticipate perfectly the customer response to price changes. We also assume that there is no control over market prices by regulators or competition authorities while also assuming that sellers do not exercise market power[199]. Even though demand for electricity depends on the user's capital stock in long-run, our conclusions and policy recommendations are based on the assumption that there will be no change in terms of ownership in home appliances or types of houses.

We present one common elasticity with respect to price, but elasticity depends on many factors including household types (target population), income levels of different customers, temperature and types of home appliances householders have in their homes. It is very important to estimate the elasticities accurately as the welfare implications of correct pricing are linked to these elasticities. In addition to this, the elasticity depends on ownership of appliances such as air-conditioners, electrical water heaters and other facilities such as swimming pools, implying that elasticity estimates vary by household type (Reiss and White, 2005)[200] We expect a higher elasticity of substitution between hours for households who have their own air-conditioners from those who do not. In this paper, we are going to apply three different own-price elasticities (-0.025, -0.050 and -0.10) to show the sensitivity of the outcomes to these elasticities. The cross-price elasticities between demands in different periods of time are assumed to be zero. Each consumer consumes so little relative to the aggregate load they cannot act strategically to alter significantly the load on their own.

We simplified the supply side of the model, working with the residual demand obtained after subtracting renewable power from the load in each hour. Although cost curves of thermal plants

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[199] The final remarks apply in deregulated markets, however, higher electricity prices above marginal costs might also exists in case of public monopoly electricity market, for example due to bad cost accounting.

[200] For instance, Matsukawa (2001) estimates price elasticity for TOU pricing using data on 279 households in Japan and estimates high price elasticity for households with electric water heaters. Reiss and White (2005) also provide detailed elasticity estimates based on ownership of various appliances and house facilities such as swimming pools.

follow a non-linear function with an increasing marginal cost, we will use a constant marginal cost per MWh of electricity generation from a given plant in our model. We also ignore start-up costs and minimum load operating levels. Therefore, short-term dispatching costs such as shut down and start-up costs other than fuel are assumed to be zero. Retail prices equal the wholesale price (ignoring fixed charges, and transmission and distribution charges per MWh for now). In addition, we assume that transmission constraints alongside the ramp rate constraints and minimum up- and down-times constraints are satisfied. This is equivalent to assuming firms have fixed cost functions within each trading interval in real-time markets. Hence, in the case of a market this implies that generators bid the same cost function across multiple pricing intervals, but in reality generators may bid differently in each trading period. There is no market power to alter electricity prices, individually or jointly by the generators. This issue in reality may significantly affect the bidding prices in power markets.

In our simulations, we compute the residual demand by subtracting the hourly renewable outputs from demand.[201] The quantities of electricity net of wind and solar electricity are thus the residual quantities that thermal plants must supply to meet demand. We assume that integrating wind into the system incurs no additional costs, so the zero marginal cost wind source of electricity output is initially displaced from the demand curve. In our simulations, we do not have minimum capacity restrictions on power generation technologies except forced renewable supply.

3.6.2 Structure of the RTP and Simulation Algorithm

Defining two electricity price structures as follows:

$$p_h^d = \begin{cases} \bar{p} & h = 1,..,H \\ p_h & h = 1,...,H \end{cases} \tag{1}$$

[201] See equation (2) in chapter 1.

where h is hour of the day, $\overline{p}$ is the fixed retail price at all hours of the day and p_h is the hourly electricity price at each hour, p_h^d is demand price in hour h

Following Borenstein and Holland (2005) and Borenstein (2005), we also define the functional form of short-run demand for electricity as follows:

$$D_h(p_h) = A_h \cdot p_h^{\varepsilon_h} \qquad \forall h \tag{2}$$

where D_h is the aggregate demand function for hour h, A_h is the scale parameter, or demand shifter that locates the demand curve at each hour based on observed demand in hour h from base case price and hourly load demand, p_h is the market-clearing price at D_h and ε_h is the constant own-price elasticity of demand.

In this demand model, we assume that consumers are willing to respond to changes in each hour's own price (-∞ <own price elasticity<0), but they are not willing to respond between hours such that a peak price increase does not affect the off-peak demand for electricity (so cross price elasticity between hours is equal to zero). Therefore, we take into account consumers' willingness to adjust from immediate response to price signals, but do not take into account load shifting between hours. This is reasonable and should not affect the qualitative results of the analysis if these cross-price elasticities between demand blocks are positive, but own-price elasticities substantially dominate the sum of cross-price elasticities across demand blocks (Taylor *et al.,* 2005; Faruqui and George; 2002). They use elasticities based upon values from the literature ranging from -0.025 to -0.2. They also apply larger elasticities such as -0.3 to -0.5 because of possible new technologies over longer term that will increase the demand response (Faruqui *et al.,* 2012).

In order to show the impacts of time-varying prices on load profiles, we simulate the changes from estimated anchor points for each hour. This is the reference point with no real time pricing, so all customers are still assumed to be under a uniform pricing structure. The hourly data on demand profile must be accurate to set this anchor point in the simulations (Borenstein, 2005). The price of $\overline{p}_c$ is not the actual flat-tariff that would be charged with the program: it only aims to show the impacts of RTP from an initial load distribution. This gives us:

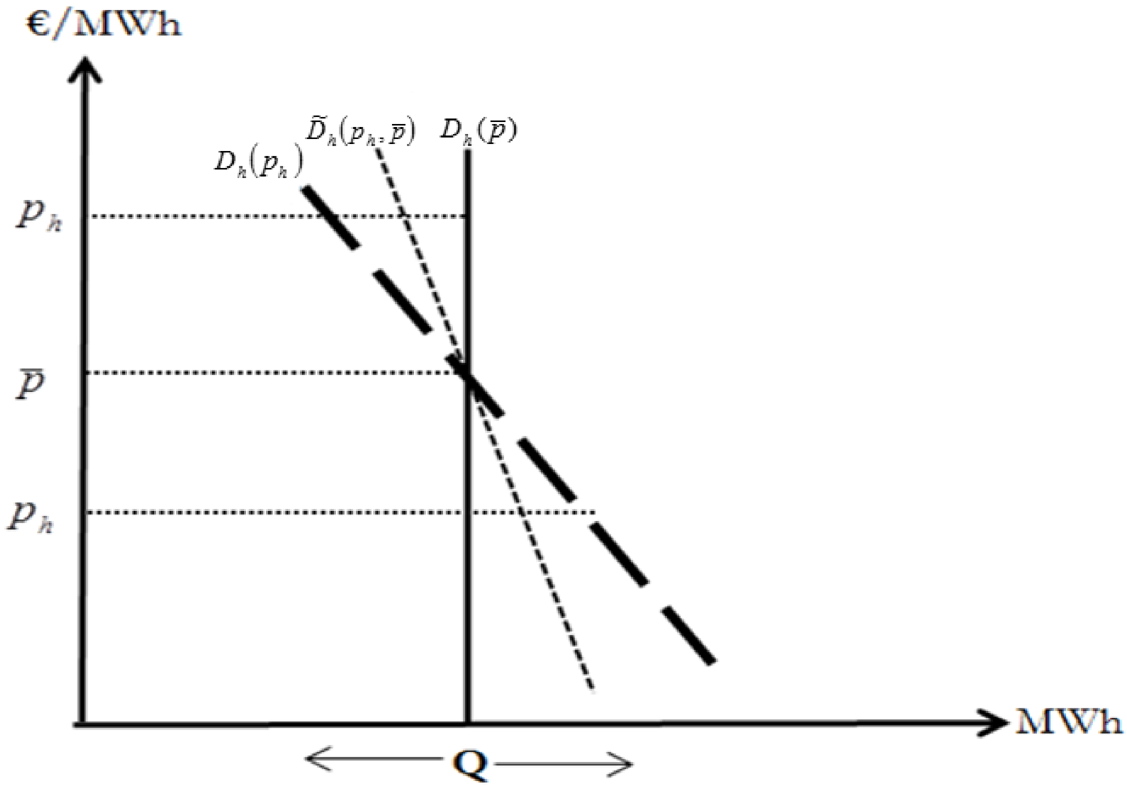
$$A_h = \frac{D_h}{\overline{p}_c^{\varepsilon}} \tag{3}$$

where $\overline{p}_c^{\varepsilon}$ is the (constant) break-even price.

Holland and Mansur (2006), Borenstein and Holland (2005), Borenstein (2005) first derive the aggregate wholesale demand from all customers. They compare the impacts of time-varying prices on load profile by splitting customers into two: a proportion (α) who pay their electricity bills at time-varying prices (p_h) and the remainder (1-α) on flat-rate electricity prices $(\overline{p})$ electricity prices.

Given this information, RTP is not the mandatory tariff for all end-use customers. If the share of end-use customers on real time pricing (α) is less than 1, then the competitive equilibrium is not Pareto efficient, and does not therefore yield the first-best electricity resource allocation in short-run or investment capacity in the long-run. The combined demand function, $\tilde{D}_h(p_h, \overline{p})$ is decreasing in p_h and $\overline{p}$. $\tilde{D}_h(p_h, \overline{p})$ is perfectly inelastic if $\alpha = 0$ as fixed retail prices create price-inelastic wholesale demand. $\tilde{D}_h(p_h, \overline{p})$ is increasing in α for $p_h < \overline{p}$ but decreasing in α for $p_h > \overline{p}$, so the wholesale demand becomes more elastic with an increase in the share of customers with RTP adoption, as shown in Figure 3.8.

Figure 3.8 Impacts of RTP Participation on Demand (Borenstein and Holland, 2005, p.472)



Therefore, defining:

$$\tilde{D}_h(p_h, \bar{p}) = \alpha \cdot D_h(p_h) + (1-\alpha) \cdot D_h(\bar{p}) \tag{4}$$

Plugging (4) into (2), we get the following expression:

$$\tilde{D}_h(p_h, \bar{p}) = \left[\alpha \cdot p_h^{\varepsilon_h} + (1-\alpha) \cdot \bar{p}^{\varepsilon_h}\right] \cdot A_h \qquad \forall h, h \in H \tag{5}$$

Based on demand equation (5), we can clearly infer that impacts of time-varying prices on the demand depend on three important elements: (i) the fraction of consumers who participate in the programme, (ii) the fraction of demand for electricity coming from participating and non-participating customers – this is what α measures – and (iii) own price elasticity estimates (ε) and their ability to respond to these prices (e.g. more elastic demand leads greater response, so greater benefits from RTP programme). Therefore, simulation results relate to the effects of RTP are based on varying parameters; α and ε. Equating demand for and supply of electricity in the wholesale market at each hour gives us the short-run equilibrium condition:

$$\tilde{D}_h(p_h, \bar{p}) = \left[\alpha \cdot p_h^{\varepsilon_h} + (1-\alpha) \cdot \bar{p}^{\varepsilon_h}\right] \cdot A_h = K_h(\lambda_h) \tag{6}$$

Where λ_h represents system the marginal cost. Therefore, we need data for the load profile and cost information of the generation mix in the system. The results are sensitive to the elasticity assumption and cost parameters of the production technologies (variable and fixed costs). The industry supply curve $K_h(\lambda_h)$ is obtained from aggregating the supply from each individual generating unit 'g'.

$$K_h(\lambda_h) = \sum_g q_g(mc_g) \tag{7}$$

In the short-run, total generation capacity is limited. Therefore, the wholesale price of electricity (wp_h) equals industry marginal costs (mc_h) of electricity as long as $\tilde{D}(p_h, \bar{p}) \leq K_{s-r}^T$, when plenty of generation capacity is available in the system, as can be seen in Figure 3.9. But, the wholesale price of electricity (wp_h) equals industry marginal cost (mc_h) plus the rationing element of the price ρ if $\tilde{D}(p_h, \bar{p}) > K_{s-r}^T$, when the capacity constraint is binding and there is a risk of excess demand for electricity capacity.

Given that:

$$K_{s-r}^T = \sum_g q_g \tag{8}$$

and

$$\widetilde{D}^T(p_h, \overline{p}) = \left[\alpha \cdot p_h^{\varepsilon_h} + (1-\alpha) \cdot \overline{p}^{\varepsilon_h}\right] \cdot A_h = K_{s-r}^T \tag{9}$$

Therefore, when there is enough installed capacity, the wholesale price of electricity will be equal to marginal cost. In periods when $\widetilde{D}(p_h, \overline{p}) > K_{s-r}^T$, the real time price of electricity has to adjust to achieve market clearing condition.

Given that both generators and retailers will maximize their profits their profit functions are written in the following form:

$\forall\ r = 1,\ldots,n$

$$\pi^r = \sum_h^H (p_h - wp_h) \cdot \alpha \cdot D_h(p_h) + (\bar{p} - wp_h) \cdot (1-\alpha) \cdot D_h(\bar{p}) \tag{10}$$

Different from retailers, generators have capacity constraints, so annualized capital costs (cost per unit of capacity multiplied by the capacity)[202] are deducted from their revenues.

$\forall\ g = 1,\ldots,m$

$$\pi^g = \sum_h^H \left[wp_h \cdot \widetilde{D}(p_h, \overline{p}) - MC_h \cdot \left(\widetilde{D}(p_h - \overline{p}), \overline{K}\right)\right] - \beta K \tag{11}$$

such that:

$$p_h = MC \text{ if } D_h \le K_{s-r}^T \tag{12}$$

P_h solves for $D_h(P_h) = K_{s-r}^T$ if $D_h > K_{s-r}^T$ as follows:

[202] These numbers are highly sensitive to the cost of capital and the rate of economic depreciation.

$$p_h = \left[\frac{K_{s-r}^{T} - (1-\alpha) \cdot \overline{p} \cdot A_h}{\alpha \cdot A_h} \right]^{1/\varepsilon} \tag{13}$$

Although wholesale markets have been open to competition during the deregulation of many electric utilities, end-use customers often still pay a flat retail price for electricity that is usually constant for months at a time. The retail sector will purchase electricity from wholesale market and distribute it to the final consumers based on real-time pricing and a flat-tariff. Retailers will charge a short-term optimal real time tariff for RTP customers that is equal to the wholesale price, if we neglect the fixed transmission and distribution charges per MWh. The RTP would also affect the flat tariff for non-participating customers. In order to satisfy the break-even profit condition for retailers from these flat rate customers, the price of electricity for them will be adjusted, such that:

$$(1-\alpha)\sum_{h}^{H}(\overline{p} - wp_h) \cdot D_h(\overline{p}) = 0 \tag{14}$$

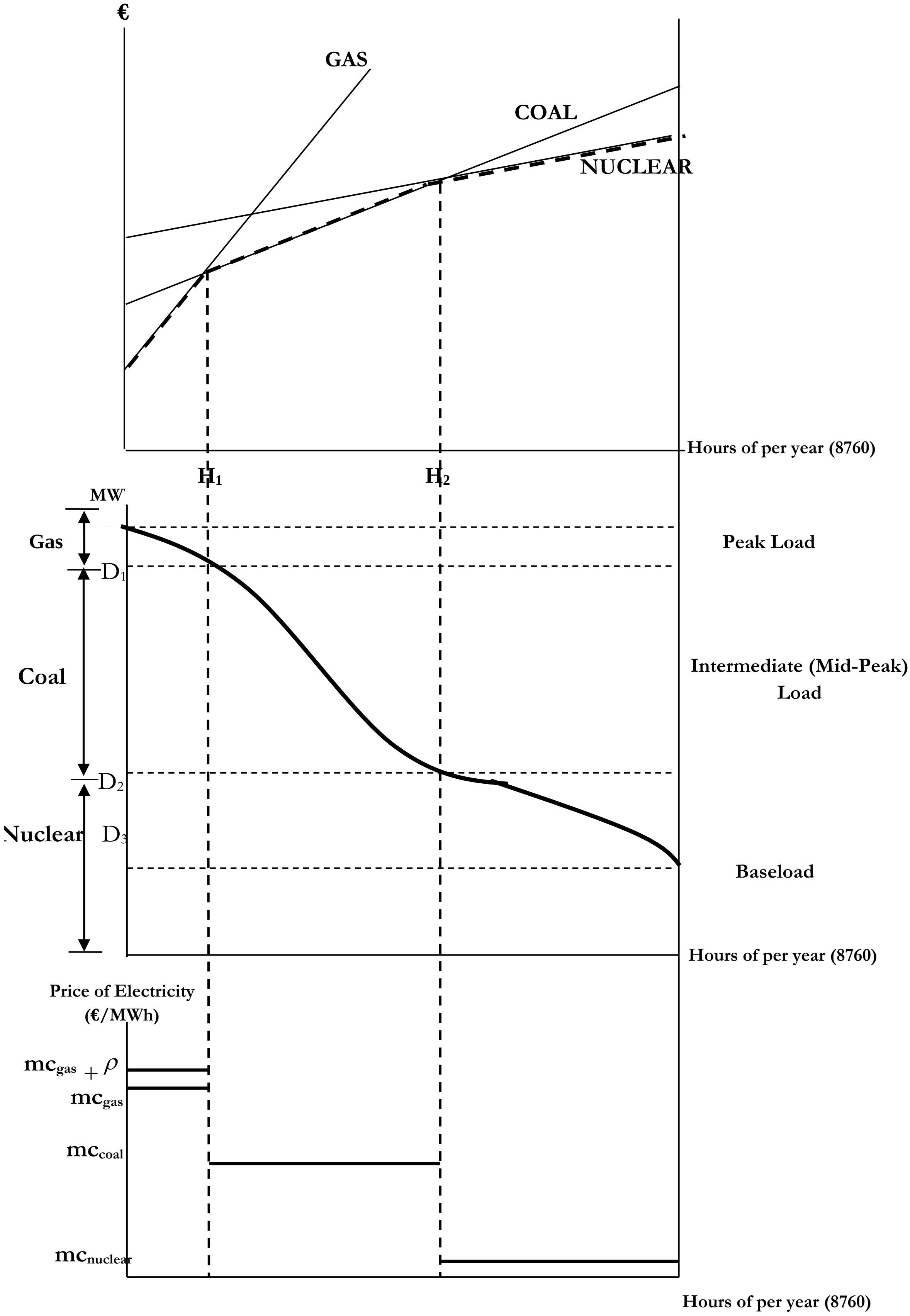
Rearranging terms and writing the equation with respect to $\overline{p}$ gives us[203]:

$$\overline{p} = \frac{\sum_{h}^{H} wp_h \cdot D_h(\overline{p})}{\sum_{h}^{H} D_h(\overline{p})} \tag{15}$$

Therefore, the short-term optimal flat-tariff $\overline{p}$ is the weighted average of wholesale prices for that period where weights are the relative quantities demanded by flat-tariff customers. In addition, this adjustment of the flat-tariff will also avoid the problem of cross subsidization between the RTP and flat-tariff customer. This is the only way to achieve equilibrium for generation and the retail sector simultaneously, with optimal prices that let retailers earn zero profits in the short-run.

[203] Also see Borenstein and Holland (2005, p. 475)

Figure 3.9 Derivation of Price Duration Curve from Screening Curve



Following the work by Borenstein and Holland (2005), and Borenstein (2005); in the long-run, capacity is built up to the point where both retailers and generators receive zero profits, which in turn leads a unique long-run equilibrium for the total available generation, K_{L-R}.

This result also holds for a welfare-maximising utility (the structure assumed for Cyprus):

$$\pi^r = \sum_h^H [p_h \cdot \alpha \cdot D_h(p_h) + \bar{p} \cdot (1-\alpha) \cdot D_h(\bar{p}) - MC_h(D_h(p_h, \bar{p}), \bar{K})] - \beta K = 0 \tag{16}$$

Similarly:

If $D_h \leq K_{s-r}^T$ then $p_h = MC_h$

If $D_h > K_{s-r}^T$ then P_h solves for $D_h(P_h) = K_{s-r}^T$ as stated in (13).

The new optimal flat tariff of electricity for non-participating customers can be also obtained from equation (15) we just described above. Since $MC_h = wp_h = p_h$, the equation (15) is not different than what we describe below:

$$\bar{p} = \frac{\sum_h^H p_h \cdot D_h(\bar{p})}{\sum_h^H D_h(\bar{p})} \tag{17}$$

These prices charged to consumers will allow the utility to cover its costs of power supply and at the same time, it will avoid cross subsidization between RTP and flat tariff customers.

3.7. Results

We show the impacts of RTP on total energy consumption (MWh), capacities (MW), emissions (tonnes), fixed and demand weighted prices (€/MWh) and welfare (€). Wind turbines in Cyprus were installed in 2010, but they were not operational until 2012. Therefore, we separate the real-time pricing simulations with and without wind power. In this way, we can capture the potential impacts of implementing RTP 'with' and 'without' wind capacities in the Cypriot electricity market. Since smart meters will be installed in Cyprus in 2020, we also test the potential impacts of wind and solar mix on the long-run capacity mix, emissions and welfare. Because an RTP programme is yet to be implemented in Cyprus and elasticity estimates for such a programme are not available, we present results simulations with varying price elasticities assuming half of the Cypriot customers are actually on the real-time pricing program[204]. The results from RTP are very sensitive to both program participation and elasticity estimates in addition to the cost parameters we described above.

In Table 3.4, we illustrate how switching from fixed pricing to real-time pricing changes the energy consumption, capacities and emissions in the power market. The results from an RTP program without wind/solar integration are as follows. In comparison to the status quo (base case without RTP program), with 50% participation in the RTP program and a low demand elasticity of -0.025, equilibrium off-peak capacity (sum of baseload and mid-merit capacities) will stay almost the same at 915 MW while the equilibrium peak capacity will decrease sharply from 217 MW to 171 MW, therefore total MW equilibrium capacity will decrease from 1,139 MW to 1,086 MW. Total energy production/consumption (i.e. total MWh) will increase from 5,194 GWh to 5,199 GWh with the real-time pricing and the increase in energy production will come from off-peak plants[205].

Keeping the program participation the same at 50%, if demand is more elastic at -0.050 and (-0.1) we find that new equilibrium off-peak capacity will decrease from 915 MW to 912 MW (908 MW), new peaker capacity will sharply drops from 171 MW to 136 MW (87 MW) and new total

[204] We will test the impacts of changes in RTP participation on the outcomes.

[205] Reduction in capacity does not mean that energy production will decrease. In this case, same amount of capacity produces more energy – in other words higher load factor.

equilibrium capacity will therefore decrease from 1086 MW to 1048 MW (995 MW). Total energy production/consumption will increase drastically at the higher elasticities with real-time pricing. For instance, keeping the program participation the same, if demand is more elastic at -0.50 and -0.1, we find that total energy production/consumption will increase from 5,199 GWh to 5,209 GWh and to 5,226 GWh, respectively. This means that while the utility will save from capacity reductions, it will have to generate more energy from the new equilibrium capacities to meet the additional demand for energy or alternatively we can conclude that the utility will be able to utilize its off-peaking capacities more with the RTP program. This will be reflected in the total cost of energy supply by means of additional fuel expenses to meet the increased demand for energy. Based on empirical results, we find that the electric utility will end up spending less on additional fuel compared to savings from capital and fuel expenditures previously made without the RTP program. For example, the total cost of power supply will decrease from €659.0 million (base case) to €658.0 million (at an elasticity of -0.0025) to €657.4 million (at an elasticity of -0.050), will further decrease to €657.0 million (at an elasticity of -0.1) at 50% program participation. These cost reductions are reflected in new optimal fixed and time-varying power prices such that fixed and real-time pricing customers will have to pay less so they will tend to consume more energy with the program.

In terms of environmental impacts of implementing real-time pricing, emissions from electricity generation will increase with the program participation at all levels of elasticity. The net change in emissions is a factor of four things: relative emission intensities of peak and off-peak plants in the system, changes in emissions from peak energy consumption savings, changes in emissions from off-peak energy consumption and the possibility of replacing mid-merit plants to operate in peak hours with lower emission intensity (depending on peak hours). In our results, we present the net changes in emissions to see whether emission reductions during peak hour consumption compensate for the increase in emissions from higher total energy consumption mostly during off-peak hours. For example, emissions from electricity generation will increase from 3.391 million tonnes (in the base case-without real-time pricing) to 3.395 million tonnes (at an elasticity of -0.025) to 3.400 million tonnes (at an elasticity of -0.05); and will further increase to 3.408 million tonnes (at an elasticity of -0.01) at 50% program participation. The increase in emissions from energy generation comes from induced energy consumption as both participating and non-participating customers will end-up paying lower prices for their additional energy consumption with the real-time pricing program. In other words, the total reduction in emissions from electricity generation during peak times is less than the total increase in emissions from off-peak electricity generation. In this analysis, we did not capture the dynamic constraints such as shut-down and start-up times of generators although this is important and might alter the results. For instance, with a greater number of peak hours, the electric utility can operate low marginal cost and less pollution emitting mid-merit plant in order to avoid using expensive to run-peaking plants.

We also compute the program benefits to customers in the form of bill savings with real-time pricing as presented in table 3.5. We initially assume that total energy (MWh) without the program is consumed equally by the two groups of customers and they pay a constant price of 130.28 €/MWh – a price that allows generators to earn zero profit. Then, we compare initial price/quantity combinations with the new price and new quantity of energy consumption to estimate the changes in total customer bills. We find that both fixed price and flexible price consumers with real-time pricing will end up paying lower prices at all levels of elasticity so both types of consumers will consume more energy than they used to consume without the program. Although fixed and real-time pricing customers will end up consuming more energy, they will still pay less on their energy bills. In other words, positive impacts of price reduction outweigh the total increase in energy consumption with the program. The values of bill savings are as follows. At low elasticity of -0.025, fixed price customers will pay €9,879 thousand less on their energy bills and RTP customers will pay €9,872 thousand less on their energy bills. The amount of bill savings with the RTP program increases at higher elasticities because of both capacity and energy cost reductions. For instance, at elasticity of -0.05 (-0.10), fixed price customers will pay €10,592 thousand (€11,382 thousand) less on their energy bills and RTP customers will pay €10,586 thousand (€11,376 thousand) less on their energy bills.

We repeat the analysis after introducing various wind and solar capacities into the system. In order to see the future potential impacts of wind and solar together, we impose both wind and solar capacities to the system and get the demand net of wind and/or solar capacities[206]. The reason for why I forced wind alone, wind and solar capacities into the system is that neither wind nor solar capacity was in the system as of 2010. In this analysis, we assume that both wind and solar sources of energy are consumed in equal amounts between the customers and they pay both fixed prices on these renewable sources (i.e. 95 Euro/MWh for wind and 200 Euro/MWh for solar)[207]. The main objective is to see how RTP program with wind alone and wind/solar power penetration affects the electricity system in Cyprus. In our simulations, the wind and solar capacities are constrained and they are deducted from the load curve in each hour.

In Table 3.4, we present the analysis on changes in capacities and emissions from electricity generation with wind/solar integration. When we introduce renewables into the system, the results are as follows. In comparison to results from implementing the real-time pricing without renewable integration and assuming demand elasticity of -0.025 and 50% participation to the RTP program, introducing 50 MW wind alone will reduce equilibrium off-peak conventional capacity from 915 MW to 904 MW and will slightly reduce the equilibrium conventional peaker

[206] See equation 12 in chapter two described on page 110.
[207] These prices reflect the MWh cost of wind and solar in the current year.

capacity from 171 MW to 168 MW and will reduce the total equilibrium installed conventional capacity from 1086 MW to 1072 MW. Keeping the participation to the programme at 50% and elasticity at -0.025, increasing the wind capacity to 100 MW (150 MW) will further reduce the equilibrium conventional baseload capacity to 894 MW (887 MW), but will leave equilibrium conventional peaker capacity unchanged. The reasons for wind not reducing the peaker capacity are that wind power is mostly available during off-peak hours and the price-reduction implications of wind power on the energy needs. Therefore, adding extra wind capacities into the system at the low elasticity will have smaller incremental effect on the equilibrium conventional capacities. At the higher elasticity, adding the same amount of wind capacities into the system will even have much smaller impact on the equilibrium conventional capacities. The reason for this again is that increasing the wind capacities will lower the energy prices so much so that the utility will need to keep conventional capacity to meet the increased demand for energy. In other words, adding wind capacities alone will not meet the increased demand for energy in the system.

In terms of environmental impacts of implementing real-time pricing with wind capacity alone, emissions from electricity generation will increase more than implementing an RTP programme alone at all levels of wind capacity and at all levels of elasticity. For example, emissions from electricity generation will increase from 3.391 million tonnes (base case) to 3.398 million tonnes (at an elasticity of -0.025 and 50 MW wind capacity) to 3.401 million tonnes (at an elasticity of -0.025 and 100 MW wind capacity) and emissions will further increase to 3.403 million tonnes (at an elasticity of -0.025 and wind capacity 150 MW) at 50% program participation. The increase in emissions is even higher with the same quantities of wind capacities but at the higher level of elasticities. In other words, the total reduction in emissions from wind electricity generation cannot compensate for the increase in emissions from conventional electricity generation.

Therefore, wind integration with real-time pricing might not provide a cost reduction in the form of emission savings.

We also compute the benefits to customers in the form of bill savings in the case of wind capacities added in the system with real-time pricing. We assume that the quantities of wind energy (MWh) are consumed equally between customers. We then compare the new price and new quantity of energy consumption with the prices and quantities without any renewables to arrive at the total customer bill savings due to wind integration. Compared to the scenario without renewables, we find that both fixed price and flexible price consumers with wind in the system will end up paying lower prices at all levels of elasticity and incremental wind capacities, except at high elasticity. At the high elasticity of -0.10, both fixed and real-time pricing customers will end-up paying higher prices with renewables than without renewables. However, real-time pricing customers will pay less with incremental wind capacities. Both types of consumers will consume more energy than they used to consume without wind in the system.

Both fixed and real-time pricing customers will end up consuming more energy due to wind quantities that they have to consume at lower fixed prices, and so they will still pay less on their energy bills. In other words, the positive impacts of price reduction due to wind are bigger than the total increase in energy prices with the wind integration. Therefore, consumers are still better-off with wind integration. The values of bill savings are as follows. At low elasticity of -0.025 and 50 MW wind integration, fixed price customers will pay €11,344 thousand less on their energy bills and RTP customers will also pay by the amount of €11,338 thousand less on their energy bills. At elasticity of -0.05 (-0.10) with 50 MW of wind capacity will reduce the energy bills fixed price customers will have to pay by the amount of €12,026 thousand (€12,784 thousand) less on their energy bills and RTP customers will pay €12,019 thousand (€12,778 thousand) less on their energy bills. At the higher elasticities, higher wind penetration will yield more savings in the form of energy bills. For instance, adding 10% wind capacity in the total system capacity (which is equivalent to having 150 MW wind in 2010) will allow fixed price customers to save up to €15,632 thousand and real-time pricing customers to save up to €15,626 thousand.

We finally compare the solar/mix scenario with wind penetration scenarios because wind capacities will be already in the system in 2020. In comparison to the real-time pricing with 100 MW wind integration case, having 50 MW wind and adding 50 MW solar into the system will reduce equilibrium off-peak conventional capacity from 904 MW to 877 MW and will reduce the equilibrium conventional peaker capacity from 167 MW to 159 MW and will reduce the total equilibrium installed conventional capacity from 1062 MW to 1035 MW. Keeping the participation in the programme at 50%, elasticity at -0.025 and reducing wind capacity at 50 MW but increasing the solar capacity to 100 MW will further reduce the equilibrium baseload conventional capacity from 877 MW to 856 MW and reduce equilibrium peaker conventional capacity from 159 MW to 147 MW.

Keeping the program participation the same, if demand is more elastic at -0.050 and (-0.1), splitting 100 MW renewable capacity equally between wind/ solar rather than adding 100 MW wind alone into the system will reduce equilibrium off-peak conventional capacity by an incremental amount of 15 MW (6 MW) and will reduce the equilibrium conventional peaker capacity by an incremental amount of 12 MW (22 MW), and will reduce the total equilibrium installed conventional capacity by 26 MW (28 MW). Therefore, adding extra wind/solar capacities into the system at the low elasticity will have larger positive impacts on the equilibrium capacities than wind alone in the system. This is due to solar availability mostly being during high demand hours when relatively expensive and dirtier plants operate in the system. Therefore, we can conclude that there are potential capacity and energy cost savings from smart metering even with low levels of consumer response, with a half participation to the programme.

In terms of the environmental impacts of implementing real-time pricing with a wind/solar capacity mix, emissions from electricity generation will be almost always smaller than wind alone except in the low wind capacity scenario with very low elasticity of -0.025. On the expectation that wind capacity will be large in the future system, adding solar capacity with capital cost reduction in solar investments in the future will potentially help the electric utility to save emission costs at all levels of elasticity. Compared to 100 MW wind capacity (i.e. 7% of total generation capacity as of 2010) in the system, adding 50 MW of both wind and solar capacity will reduce emissions from electricity generation from 3.401 million tonnes to 3.399 million tonnes at an elasticity of -0.025; from 3.405 million to 3,401 million tonnes at an elasticity of -0.05; and will further increase from 3.414 million to 3.411 million tonnes at an elasticity of -0.01. The reduction in emissions is even higher with the same quantities of wind capacities but a higher capacity of solar integration.

When we introduce a mix of wind/solar capacities into the system, we find that mix of wind/solar capacities will allow utilities to save more from capacity and energy during off-peak and peak hours[208]. That is to say, wind/solar combination work better and are complementary sources of renewable energy when real-time pricing is introduced. With real-time pricing and possible reductions in solar technology costs, we can argue that wind/solar together will be economically more viable in the near future by means of both capacity (MW) and energy (MWh) cost reductions, and emissions cost penalties. In other words, the levelised cost of avoided energy and emission costs and the capacity credit value from wind/solar integration will be potentially bigger than the levelised cost of solar energy with the real-time pricing program.

[208] Note that although energy reduction is substantial, total cost of power supply increases with mix of wind and solar as solar energy today is still not competitive and very expensive source of renewable energy.

Table 3.4 Capacity and Emissions Impacts of Real-Time Pricing, "with" and "without" renewables

	Wind Capacity (MW)	Solar Capacity (MW)	Conventional Energy (MWh)	Wind Energy (MWh)	Solar Energy (MWh)	Total Energy (MWh)	Equilibirum Capacities (MW)			Total Capacity	Total System Cost	Super Peak Hours	Emissions
							Baseload	Mid-Merit	Peak				
Base	0	0	5,191,476	0	0	5,191,476	690	225	224	1139	659,043,564	75	3,391,053
-0.025	0	0	5,199,751	0	0	5,199,751	690	225	171	1086	657,979,369	103	3,395,462
-0.025	50	0	5,199,785	94,178	0	5,293,963	679	225	168	1072	659,427,361	108	3,398,384
-0.025	100	0	5,199,859	188,357	0	5,388,216	670	224	167	1062	661,037,949	108	3,401,041
-0.025	150	0	5,193,834	282,535	0	5,476,369	663	221	169	1053	662,759,088	116	3,403,266
-0.025	50	50	5,191,188	94,178	93,899	5,379,265	669	208	159	1035	666,553,119	119	3,398,876
-0.025	50	100	5,184,421	94,178	187,798	5,466,397	663	193	147	1002	673,941,603	111	3,397,513
-0.5	0	0	5,208,762	0	0	5,208,762	691	222	136	1048	657,427,451	100	3,399,649
-0.5	50	0	5,206,565	94,178	0	5,300,743	680	222	132	1035	658,867,107	114	3,402,624
-0.5	100	0	5,204,438	188,357	0	5,392,795	672	221	130	1022	660,436,060	117	3,405,287
-0.5	150	0	5,202,355	282,535	0	5,484,890	664	218	129	1011	662,105,838	105	3,407,550
-0.5	50	50	5,199,744	94,178	93,899	5,387,822	670	208	118	996	665,954,856	122	3,402,829
-0.5	50	100	5,193,386	94,178	187,798	5,475,362	664	195	102	960	673,287,629	97	3,401,542
-0.1	0	0	5,226,072	0	0	5,226,072	693	215	87	995	657,032,943	102	3,408,103
-0.1	50	0	5,223,836	94,178	0	5,318,015	682	216	84	982	658,497,868	134	3,411,101
-0.1	100	0	5,221,747	188,357	0	5,410,104	674	215	80	969	660,067,582	130	3,413,656
-0.1	150	0	5,219,795	282,535	0	5,502,330	667	214	77	957	661,722,584	134	3,415,928
-0.1	50	50	5,217,685	94,178	93,899	5,405,763	672	211	58	941	665,572,224	123	3,410,898
-0.1	50	100	5,208,434	94,178	187,798	5,490,411	666	214	24	903	672,083,284	109	3,404,501

Source: own estimates

Table 3.5 Welfare Impacts of Real-Time Pricing, "with" and "without" renewables

	Wind Capacity (MW)	Solar Capacity (MW)	Fixed Price (€/MWh)	Fixed Price Consumption (MWh)	Demand-Weigted Price (€/MWh)	Demand-Weigted Consumption (MWh)	Energy Bill Savings Fixed Price Customers (€)	Energy Bill Savings RTP Customers (€)
Base	0	0	130.280	2,595,738	----	2,595,738	-----	----
-0.025	0	0	126.378	2,597,712	126.168	2,602,039	9,878,910	9,872,546
-0.025	50	0	126.368	2,644,806	126.157	2,649,157	11,344,502	11,338,133
-0.025	100	0	126.350	2,691,905	126.136	2,696,311	12,833,214	12,826,858
-0.025	150	0	126.340	2,738,999	126.122	2,743,497	14,298,258	14,291,905
-0.025	50	50	126.396	2,668,267	126.178	2,696,238	7,817,231	7,800,994
-0.025	50	100	126.413	2,691,733	126.179	2,743,490	4,319,772	4,293,646
-0.5	0	0	125.988	2,600,089	125.602	2,608,086	10,591,754	10,585,642
-0.5	50	0	125.991	2,647,175	125.603	2,655,219	12,026,104	12,019,983
-0.5	100	0	125.986	2,694,270	125.592	2,702,413	13,480,555	13,474,445
-0.5	150	0	125.978	2,741,367	125.578	2,749,649	14,941,228	14,935,119
-0.5	50	50	126.021	2,670,619	125.618	2,702,440	8,495,361	8,479,371
-0.5	50	100	126.015	2,694,100	125.579	2,750,086	5,053,448	5,027,592
-0.1	0	0	125.417	2,605,631	124.736	2,619,850	11,381,921	11,376,239
-0.1	50	0	125.434	2,652,686	124.749	2,666,976	12,784,042	12,778,360
-0.1	100	0	125.445	2,699,752	124.751	2,714,236	14,199,939	14,194,254
-0.1	150	0	125.449	2,746,833	124.741	2,761,619	15,631,780	15,626,095
-0.1	50	50	125.444	2,676,139	124.714	2,714,859	9,303,676	9,288,123
-0.1	50	100	125.362	2,699,785	124.567	2,763,354	6,040,347	6,014,951

__Source:__ own estimates

We also compute the benefits to customers in the form of bill savings in the case of wind/solar capacity mix with real-time pricing. We assume that both wind/solar quantities of energy (MWh) are consumed in equal amounts by the two customer groups. We will again compare the solar/mix scenario with wind penetration scenarios. Except at the high elasticity of demand -0.10, compared to 100 MW wind capacity alone, both fixed and real-time price customers will pay more with 50 MW each wind/solar integration or higher solar integration. This is because consumers have to pay high fixed prices for solar energy and prices for conventional energies from wind/solar integration will be higher than wind alone. Lower energy bill savings come partly from higher prices for conventional energy to cover the fixed capacity costs and partially due to the high cost of solar energy. Both types of customers are still better off without the programme, however.

The values of bill savings are as follows. At a low elasticity of -0.025 and 50 MW/each wind and solar integration, fixed price customers will pay €7,817 thousand less on their energy bills and RTP customers will also pay the amount of €7,801 thousand less on their energy bills. The amount of bill savings with the RTP program increases at higher elasticity because of both peaker capacity and energy reductions. For instance, at elasticity of -0.05 (-0.10), 50 MW of wind capacity will reduce the energy bills fixed price customers will have to pay by the amount of €8,495 thousand (€9,310 thousand) and RTP customers will pay €8,479 thousand (€9,288 thousand) less. At all elasticities, higher solar penetration will yield fewer savings in the form of energy bills, in fact almost half. Given that solar costs will not be lower than the wind cost, customers will be better-off with wind/solar integration but solar capacity should not exceed the wind. This is true as the value of wind energy will increase over time with real time pricing.

3.8. Conclusions and Policy Recommendations

We set out a theoretical model that simultaneously incorporates demand response and wind and solar sources into the electricity market, which we applied to the island of Cyprus power system. Based on our empirical results, we clearly see that the load curve will flatten with dynamic pricing, which means off-peak demand for capacity is increased relative to peaking demand, which is translated into a higher load (capacity) factor and better utilization of off peak capacity (supply) in the system. Since electricity prices in the market are set by thermal plants, consumers who join and do not join the RTP program end up paying lower average prices for the electricity they consume. Given this, we also estimate the changes in consumer welfare from such dynamic pricing. In comparison to a fixed pricing of electricity, we find that both fixed and real-time pricing customers will be better off as they will both pay lower prices for their increased consumption than without the program. The emissions from electricity generation will increase, however. The increase in emissions comes from an increase in MWh energy generation and consumption during off-peak times, which is higher than emission reductions during peak hours.

We also find that dynamic pricing promotes renewable investments that generate electricity more during off-peak hours (wind) and peak hours (solar). Based on the power supply mix in Cyprus, a mix of wind/solar will reduce equilibrium total thermal capacity in the system by lowering peaker capacity sharply as well as reduce the energy generation from conventional plants. This will reduce costs in the system with decreasing solar costs, will help the utility to save fuel, reduce emissions from electricity generation. The overall conclusion for Cyprus would be that dynamic pricing of electricity will increase capacity utilization, reduce power prices in Cyprus, reduce emissions from electricity generation and increase the use of wind/solar resources in the island. Hence, the Cypriot authorities should let market participants react to changes in electricity prices. This means that the country should switch to smart metering and shift away from an average pricing of electricity.

Given that solar energy will allow the utility to save both capacity and energy (and so emissions), comparisons of the levelised cost of avoided energy with and without the wind/solar mix will potentially allow the utility to decide and set the green tariffs with the program. This is because the levelised cost of solar energy is not estimated based on capacity and energy savings from a renewable source. And, the levelised cost of avoided energy production estimates for wind and the "right mixture" of wind and solar with the real-time pricing program might bring solar capacities to the system earlier than predicted without necessarily giving subsidies in later years with very high wind capacities.

3.9. Limitations of Research and Future Research

In this research, we could only assume values for the demand parameters such as elasticity coefficients and consumers' willingness to join such programmes while analysing the impacts of implementing real-time pricing. Advanced Metering Infrastructure (AMI) will require substantial investments to correct the inefficiency of fixed electricity prices. The welfare implications of correcting this inefficiency depend on not only the investments in AMI system but significantly on how price elastic the consumers are – on their ability and willingness to respond to prices and by how much. If we assume that consumers who will join the programme will pay the capital cost of these investments, they must compare the benefits in the form of energy bill savings against the price they will have to pay for joining the programme. It is also equally important to distinguish between the amount of different types of benefits from such pricing as well as who will gain and lose from it and by how much. Therefore, it might be costly to the utility and to consumers simply to assume that consumers behave in the way we want them to.

These demand parameters, however, significantly determine the welfare implications of such pricing. At the same time, correct estimates can only effectively guide policy makers and/or regulators to implement real-time pricing and make the necessary arrangements before and during the actual implementation this radical shift. To illustrate, although we expect consumers to reduce their peak demand whilst increasing their off-peak demand for energy, consumers might not react as we expect from them. For instance, the experiment of Alcott (2011) finds that US residential consumers are price elastic to their energy demand, and they reduce their peak demand but they do not increase their average consumption during off-peak times. Therefore, before implementing such programs, policy makers or regulators should conduct similar experiments on both residential and industrial customers to verify these elasticities. Given that cost of generating (at wholesale stage) and selling electricity (at retail stage) is highest in Cyprus compared to other EU member states, implementing such a program might increase the retail prices with no or little return to consumers.

Another limitation is that we did not identify and monetise all benefits of marginal cost pricing. It is, however, important to identify and monetise the full array of potential benefits from real-time pricing. For instance, the reliability benefit of moving to real-time pricing should be considered and added as a market-wide benefit because it affects all participants in the market. The monetary value of enhancing reliability from RTP might come from reduction in revenue losses from less planned outages, reduction in capacity investments to maintain reserve capacity from reduced peak capacity, reduction in coping costs from not running self-generating units especially during high demand hours etc. The answer to the question of 'how many hours of outage per year potentially might be reduced from RTP?', and the estimate of 'what is the value of lost load' would provide an approximate answer to this question[209].

In Cyprus, the variable cost of power generation is dominated by the fuel price but the Electricity Authority of Cyprus also increases the prices when generators emit more than allowed. In our analysis, we excluded the emission price from the variable cost, but it would be better to see (i) the impacts of RTP in the system with and without emission price, and (ii) the impacts of RTP with wind/solar mix integration considering the effects of the emission price on the capacities, prices and emissions themselves. In this way, we can clearly see how much actually RTP alone and RTP with wind/solar integration change the system capacities, energy prices and emissions. Then, we can conclude whether these energy policy instruments are complementary or substitutes for each other. These issues can be corrected in the model. But, the price implications of such analysis are quite a complex task for the utility and have feed-back effects on capacities and emissions. The questions coming from such analysis are: by how much participating and non-participating customers should (and will) benefit from wind integration and by how much participating and non-participating customers should (and will) pay for higher emissions. If the Electricity Authority of Cyprus informs consumers how these renewable benefits and emission penalties will be distributed among consumers, both the participation in RTP programmes and their impacts might change. Hence, this is worth studying before implementing such programs.

[209] Note that potential energy, capacity and emissions savings from critical peak pricing (CPP) should be also studied as the demand for electric capacity in Cyprus is just above 85% of the peak demand for about 2% of the time. This simply means that the results from implementing CPP pricing might or might not generate greater benefits and be simpler to achieve. The government of Cyprus, however, will implement real-time pricing and critical peak pricing is not under discussion by the regulators and local authorities.

Appendix

Glossary

h is hour of the day, h=1,…,8760

$\overline{p}$ is the fixed retail price at all hours of the day

p_h is the hourly electricity price at each hour

p_h^d is demand price in hour h

D_h is the aggregate demand function for hour h

A_h is the scale parameter, or demand shifter that locates the demand curve at each hour based on observed demand in hour h from base case price and hourly load demand

ε_h is the constant own-price elasticity of demand

$\overline{p}_c^{\varepsilon}$ is the (constant) break-even price

α is the share of end-use customers on real time pricing and pay p_h

(1-α) is the remainder who are on flat-rate electricity prices $(\overline{p})$

$\widetilde{D}_h(p_h, \overline{p})$ is the total demand for capacity that comes from RTP participating and non-participating customers

$\mathrm{wp_h}$ is the wholesale price of electricity in hour h

MC_h is the marginal costs of electricity in hour h

K_h is the system capacity, MW

β is the capital charges

K_{s-r}^{T} is the total capacity available in the system, MW

q_g is the capacity supplied from each generator g

π^g Is the profits of generator g

π^r Is the profits of retailer r

OVERALL CONCLUSIONS

Electricity generation from fossil fuels threatens the long – term growth of countries due to their limited availability, volatile prices and mounting environmental externalities. Therefore, energy policies today must achieve a delicate balance between sustaining economic growth and preservation of the environment for current and future generations. This involves finding a set of generation sources so as to meet energy requirements in a manner which is both cost-effective and environmentally friendly.

Renewable sources are available in many island economies. The main motivations for switching electricity generation to renewables are their potential to help sidestep increasing fossil fuel prices, reduce external dependency of non-oil producing countries on imports whilst maintaining system reliability (meaning both energy security and energy adequacy). These desires are stronger for island economies as they are vulnerable to high fuel dependency in their energy supply and a high cost of generating the electricity, while the reliability of their power supply can be low. These problems in turn have debilitating effects on their economies.

In chapter 1, we provide a method to allocate and evaluate the quantified and monetized benefits/costs from grid-connected wind investments. The interest groups included in this study are the private supplier, the electric utility, the country-economy and the national government. Then, we apply our framework to obtain the actual impacts of grid-connected wind investments on each stakeholder if this wind farm project is undertaken by the private sector. Using this method, we can capture the net earnings of each interest group so that we can contemplate redistribution of the benefits and costs to compensate the losers. For example, we can transfer some benefits from the private sector to the national economy if that economy is earning very little return from the wind farm project while the private sector entity earns a substantial return. This is possible via negotiating over the PPA prices or more precisely, stating what are the break-even prices. In the literature, such analyses have been carried out typically on the basis that the electric utility owns and operates the renewables, but in reality, such projects are often undertaken by the private sector.

In this analysis, we evaluate the wind power project at the generation level. Although some fraction of wind might not be transmitted and delivered to end-users, this study excludes such losses. It is however worth including these losses especially in those countries (e.g. Cape Verde) where the quality of system infrastructure is poor and the system is undergoing rehabilitation. Based on our empirical results, we conclude that wind generation will yield high economic and financial returns (from the utility's point of view) in Cape-Verde as energy generation from diesel plants is extremely costly to the utility (and so to consumers). Hence, we can conclude that connecting existing customers to the wind farm (or any grid-connected renewable) will potentially increase social welfare by means of price reductions for existing consumers and will allow the utility to recover its costs, and will also allow the utility to improve reliability given that existing connections already suffer from chronic power supply unreliability and high electricity prices. Additionally, the utility will be able to expand electrification from fuel cost savings that will bring even more societal benefits given that a large fraction of the population still live in the dark. Finally, ex-post analysis undertaken in similar countries is highly recommended as part of the decision-making process when it comes to the distribution of utility level benefit in order to maximize welfare from wind integration with private sector opening[210].

[210] Looking at price changes alone in countries with large utility debts and low electrification cannot provide us with sufficient information whether investments in renewables are cost-effective or not.

In chapter 2, our primary objective is to test the effect of green energy regulations on the electricity generation mix to see whether these investments are a cost-effective way to reduce emissions and achieve a renewable energy share in electricity generation. To do this, we define our objective function to minimize the costs and emissions from electricity generation while satisfying the regulatory constraints alongside other system constraints. We apply the proposed model for Cyprus where wind and solar sources of electricity generation will inevitably increase to meet emission reduction and renewable targets set by regulators.

The use of renewable sources in the Cypriot national electricity supply will increase in order to comply with its renewable targets and reduce emissions from electricity generation as set out by the regulators. This chapter investigates the impacts of wind and solar renewable power sources on both electricity generation and planning by employing a cost minimization model including economic, technical as well as regulatory constraints such as renewable targets. The cost minimization model demonstrates that the use of wind and solar power together in an electricity generation mix reduces the overall cost of the system. Given the fact that solar power will not be utilized in the national grid in the near future, current public policies in promoting renewables in the form of taxes and other policy measures impair the system by relying on wind alone in the thermal-renewable generation mix. In the first place, as the market for wind and solar has grown, so the costs per kWh are rapidly decreasing over time. From the empirical analysis, we suggest that it is not yet the right time to shift to renewable energy sources in Cyprus and it is better to postpone such capital intensive investments in electricity generation. These conclusions are based on the assumption that consumers will pay fixed regulated tariffs for their energy consumption.

In chapter 3, we study the impact of real-time pricing on the Cyprus power system as a way to improve the utilization of off-peak generation capacity and save on peaking capacity when the proportion of variable renewables (wind and solar) increases. We apply a merit order stack approach to generation investment and operation decisions so that a system planner minimises the total cost of capacity and output to meet the changing demand for capacity and energy with real-time pricing.

We conclude that dynamic pricing will help the utility to get rid of excess capacity (that is peak capacity) and will increase the load factor of existing capacity. Because it will allow consumers to pay lower prices for their energy consumption, it will however increase the total electricity generation. This is reflected in fuel spending and emissions from electricity generation. Without any renewable generation in the system, the total cost of power supply will decrease but emissions from electricity generation might increase with the induced energy consumption as emissions are a function of output and emission levels from power generators – not their capacities. With respect to consumer bills, we find that both fixed-price and real-time pricing customers will consume higher quantities from lower energy prices but will end up with lower energy bills compared to a fixed regulated tariff. These savings are larger at higher elasticities. Because wind (solar) availability comes mostly during low (high) demand hours when relatively cleaner (dirtier) plants operate in the system, we find that there is considerable potential for capital cost savings and emission savings from smart metering even with only a small consumer response, and/or with moderate participation in the programme. At the current costs of solar, investing in wind alone will however yield higher bill savings.

This thesis has studied three aspects of renewable integration in two small island states. In Cape Verde, we showed that wind power could bring benefits to the utility, its consumers and the private investor, in part because of the high price of the imported fuel that it would displace. The distribution of these benefits, however, depends on the prices that are negotiated with the developer. In Cyprus, chapter 2 showed that wind investments would increase the financial cost of power supply (at the fuel prices studied) but bring significant emissions reductions. Solar PV power, in contrast, would reduce the cost of power because its output comes at a time when it can displace the most expensive peaking plants. Chapter 3 showed how the introduction of real time pricing in Cyprus would help with the integration of renewable power by smoothing patterns of demand and matching them to the availability of wind and solar generation. This would help to reduce consumers' bills. On the island of Cyprus, the combination of wind and solar power, with complementary output patterns, would provide a better trade-off between cost and emissions reductions than wind power alone.

One avenue of future research is to consider the impact of future changes in technology and fuel prices on the trade-offs shown in this thesis. Cape Verde found wind generation to be cost-effective because of the price of its fuel imports; if fossil fuel prices rose more generally, or the cost of wind turbines fell further, then Cyprus might also save money from investing in wind. Case studies in other islands could help to determine the importance of the temporal pattern of wind and solar generation in comparison to the local electricity demand, since a country with a peak load at times when renewable generation is not available will not be able to save on conventional generating capacity by investing in these renewables.

It is possible that energy storage will have a role in smoothing the delivery of renewable output, and that this would increase the benefits from it; however, the costs of energy storage devices are currently high. The models used in this thesis respect the most important engineering constraint in the electricity industry, that generation must always equal demand, but do not take into account the need to have reserve capacity or to respect constraints on the transmission system. These additional factors are unlikely to overturn the main results given here, but a more complete study would take them into account. Doing so would involve interdisciplinary work with electrical engineers and would be an interesting future challenge.

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