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Rethinking how to support intermittent renewables

BY
Patrick A. Narbel

Norges Handelshøyskole
NORWEGIAN SCHOOL OF ECONOMICS

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Patrick A. Narbel[a]

[a]*Department of Business and Management Science, Norwegian School of Economics, Helleveien 30, 5045 Bergen, Norway*

Abstract

Intermittent renewable energy sources, including solar and wind power, typically remain more expensive than conventional power sources. As a consequence, few intermittent power projects would have been deployed if specific policy instruments had not been implemented. Existing policy instruments facilitating the deployment of intermittent renewable energy technologies include the feed-in tariff, the feed-in premium and the quota system. Based on a numerical analysis, it is shown that these specific policy instruments do not necessarily facilitate the deployment of valuable energy sources because they ignore the cost of intermittency. A valuable intermittent energy source is defined here as a source of energy which requires little financial support and which limits the need for capacity payments in order to ensure the security of supply. Based on insights from the numerical analysis, a new policy instrument is suggested: a multiplicative premium. This type of policy instrument would increase the likelihood that valuable intermittent energy assets are deployed in priority.

Keywords: Intermittent renewables, value of energy, security of supply

1. Introduction

Intermittent renewable energy generating technologies (e.g.: wind and solar power) have a low carbon footprint and thus can be part of a larger solution to mitigate the anthropogenic impact on climate. In addition, such technologies can contribute to increased energy security if their deployment reduces the need for fossil fuel imports (Narbel, 2013), they can reduce

Email address: patrick.narbel@nhh.no (Patrick A. Narbel)

local air pollution (van Kooten, 2010) and they have the potential to address concerns on the projected depletion of fossil fuels (Dinica, 2006).

Despite a recent fall in the cost of wind and particularly of solar power, intermittent renewable energy technologies are not competitive at current market prices (Gawel and Purkus, 2013) and few intermittent power projects would be realized without some type of support. As a consequence, specific policy instruments to stimulate investment in intermittent renewable energy technologies (Gowrisankaran et al., 2011) have been put in place by countries seeking the benefits of these technologies.

The use of specific policy instruments directed towards renewable energy was found to be justified when a direct intervention such as a carbon tax, a first-best solution, may not suffice to stimulate enough deployment to generate learning which will lead to cost reductions (Menanteau et al., 2003; Palmer and Butraw, 2005), when a carbon tax cannot correct all externalities in the energy sector or when implementing a carbon tax is politically difficult (Kalkhul et al., 2013). Hence, a specific policy instrument is a feasible temporary pragmatic alternative to a first-best optimum (Kalkhul et al., 2013).

Existing policy instruments can be distinguished between price-based (e.g.: feed-in tariffs, feed-in premiums and bidding processes) and quantity-based instruments (e.g.: quota systems) (Menanteau et al., 2003). An issue associated to such policy instruments is that they are more complex to administer than a carbon tax (Green and Yatchew, 2012). As such, a significant amount of 'guessing' (Hirth et al., 2013) is required from policy makers on the short and long-term costs and benefits of these technologies in order to make the policy instrument effective and efficient.

Many studies have concluded that feed-in tariffs have proven to be the most *effective* amongst the common policy instruments (Couture and Gagnon, 2010; Finon et al., 2002; Green and Yatchew, 2012; Menanteau et al., 2003), because they provide the plant owner with long-term financial stability (Lesser and Su, 2008). Effective policy instruments are those resulting in the rapid deployment of renewable energy supply. Nevertheless, a rapid development may not be *efficient*, especially if the policy instrument does not incentivize investors to build energy sources which deliver when energy is the most valuable (Green and Yatchew, 2012).

Both effectiveness and efficiency of a policy instrument are traditionally measured in terms of the direct cost of energy and some researchers (Green and Yatchew, 2012; Gowrisankaran et al., 2011; Jaegemann, 2014) are now suggesting a move towards instruments based on the realized value of energy instead. Two criteria shall be used in this study to define a valuable intermittent energy source: An intermittent source of energy is deemed valuable if it generates power during high-prices hours and if it limits the need for capacity payments implemented to guarantee the security of supply. The first criterion pertains to the direct cost of generating electricity, whereas the second criterion reflects the cost of intermittency. The emphasis is then put on how specific policy instruments perform at delivering valuable intermittent energy to the power system.

Based on a numerical analysis using historical day-ahead data for West Denmark, a general point made is that existing policy instruments do not necessarily reflect the value of energy and that there is consequently a need for a new system which will minimize the total cost of generation (Lamont, 2008). A uniform multiplicative premium is proposed, which would reward power station owners whose power production matches the market needs. Simple to administrate, such policy instrument would be more likely to facilitate the deployment of valuable intermittent renewable energy projects as the Danish example will illustrate.

The rest of the paper starts by theoretically defining a valuable intermittent source of energy in Section 2. Section 3 consists of a numerical analysis to determine how effective existing policy instruments are at facilitating the deployment of valuable intermittent renewable energy. An alternative policy instrument is proposed in Section 4. Finally, Section 5 concludes.

2. Definition of a valuable intermittent energy source

A number of authors have tried to define what a valuable intermittent energy project is. For instance, Gowrisankaran et al. (2011) define a valuable intermittent energy source as a source of energy which production of electricity correlates with the load. Hirth (2013) sees the market value of an intermittent energy source as the revenues a generator can earn on the market in the absence of subsidies. In a more advanced version, Lamont (2008) think of the long-term marginal value of an intermittent power station as a function of the station's capacity factor and of the covariance between the production of electricity and the system marginal cost. The most valuable power projects are those which allow for a reduction of the capacity of dispatchable power plants while maintaining the same level of system reliability. The definition of a valuable intermittent renewable energy project used here is closest to Lamont (2008) and is based on two metrics: the spot price and the cost of intermittency.

2.1. Spot Price

Each intermittent renewable power station has a unique electricity production pattern, which depends on the technology and the location. For example, some wind farms located along a coastline generate most of their power in the morning and late in the afternoon when thermal inversion between land and sea occurs. The production of electricity of a solar photovoltaic (PV) power station is directly linked to incoming solar radiations. A PV power station will consequently produce more electricity during day-time than at night and more electricity over summer than over winter. If the general production pattern of an intermittent power station is known, the exact production pattern is stochastic, for example by cause of changing wind, cloud coverage and temperature. These production patterns will match differently the market needs (i.e. the spot price), hence making some renewable power stations more valuable than others.

The evolution of a spot price over 24 hours and the electricity production profiles of two intermittent renewable technologies are illustrated in Fig. 1.

The electricity production profile of the second intermittent technology (right graph) better matches the needs of this particular market because more power is generated during high prices hours compared to the first technology. Hence, the electricity produced by the second technology is more valuable.

In the absence of policy instrument and costs being equal between technologies, the expectation on future spot prices would be sufficient to lead to the construction of the most valuable power projects. However, the lack of competitiveness of the intermittent technologies in the current electricity market has forced policy makers to implement some type of

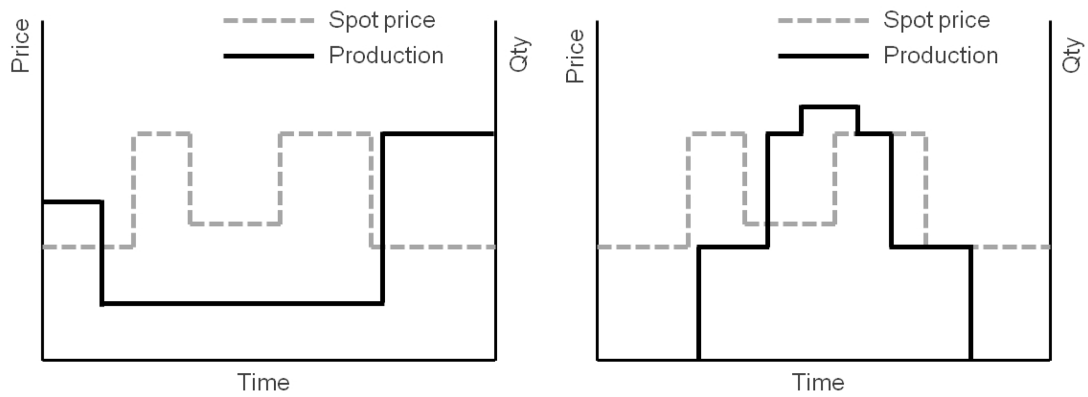

Figure 1: Spot price (measured on the left axis) and production of electricity from two intermittent renewable energy technologies (measured on the right axis).

policy instrument in order to facilitate their deployment. These policy instruments will provide incentives to investors, who estimate the profitability of an investment based on various approaches, including the net present value (NPV) approach. A version of the NPV formula valid for an intermittent renewable energy project is:

$$V = -I + \sum_{y=0}^{Y} \frac{\sum_{h=0}^{H} q_h(e(\mu,\sigma)) \cdot p_h(T_h, D_h, S_h) - C_y}{(1+r)^y} \tag{1}$$

where I stands for the initial investment, y is the year of the cash flow and Y is the duration of the project. The discount rate r is the factor adjusting future cash flows for risk and the time value of money. The quantity of electricity q produced in hour h depends on an exogenous factor e such as wind speed or incoming solar radiation, which is stochastic with a mean μ and a variance σ. The price p_h depends on the tariff T_h implemented to support the deployment of intermittent renewable energy, on the demand function for power D_h and the supply function of power from other sources S_h. Finally, C_y accounts for the operational costs.

Since the price perceived by the plant owner depends at least partly on the policy instrument in place, the design of such policy instrument is important. For instance, the revenues of power projects built under a feed-in tariff[1] come solely from the policy instrument rather than being market-based. The numerical analysis will show that a feed-in tariff does not incentivize investors to primarily deliver power projects which generate energy when market prices are high. As a consequence, the energy delivered may be of limited value to the system.

2.2. Cost of intermittency

The second metric defining a valuable intermittent energy project pertains to the cost of intermittency. The security of supply requires that consumers can obtain electricity when they need it. Given the inherent characteristics of intermittent renewable energy, the security of supply cannot be guaranteed by solely relying on intermittent renewable energy (van Kooten, 2010; Oswald et al., 2008). Therefore, dispatchable capacity is needed to compensate for the intermittency of some technologies and balance demand and supply of electricity at all times. While the dispatchable capacity is still needed in the presence of intermittent renewable energy, the economics of the extant generation mix is likely to be negatively impacted (Jacobsen and Zvingilaite, 2010).

In a functioning electricity market such as the Nord Pool power market, a power plant owner will decide how much energy he can deliver in a given hour and for what price; normally the marginal cost of producing power. Such action is known as placing a bid and if accepted, the plant owner will receive the market price per MWh supplied.

The levelized cost of energy of a power plant can be calculated using:

$$\mathrm{LCOE} = \frac{C_c \cdot R}{f \cdot H} + l \cdot \frac{C_o^{\mathrm{fixed}}}{f \cdot H} + \underbrace{l \cdot C_o^{\mathrm{variable}} + l \cdot \frac{C_f}{f \cdot H}}_{\text{marginal cost}} \tag{2}$$

where C_c is the capital cost, C_o is the series of annualized fixed and variable operation and maintenance (O&M) costs, C_f is the series of annualized fuel costs, H is the number of hours in a year, R is the capital recovery factor, f is the capacity factor and l is a levelization factor.

[1] A feed-in tariff is a policy instrument which guarantees a fixed price for every unit of electricity sold.

The marginal cost of producing energy for a thermal power plant is equal to the sum of the variable and fuel costs incurred to generate electricity. The difference between the marginal cost and the spot price then serves to cover the fixed variable costs and capital costs, and to generate a profit. As long as the average market price per unit of electricity sold exceeds the levelized cost of the plant, the plant owner will realize a positive return over investment. Everything else being equal, the deployment of intermittent renewable energy will pressure the economic viability of the extant dispatchable capacity. This is because the deployment of zero marginal cost energy will force dispatchable power plants to curtail their production of electricity[2]. Such reduction in electricity production will force existing power plants to spread their fixed costs over fewer units of energy (in Eq. (2), f diminishes), hence augmenting their levelized costs. Past a threshold, this situation may lead to the retirement of a number of dispatchable power plants. Assuming that some of these plants are critical to ensure that sufficient capacity is available in times of high residual loads, retiring dispatchable capacity will threaten the security of supply. In such situation, policy makers may be forced to introduce some sort of capacity payment mechanisms[3] to improve the economic viability of dispatchable power plants and ensure that these plants remain online (MacCormack et al., 2010). These capacity payments are thus a consequence of the intermittency issue of some renewable energy sources (Oliveira, 2013).

The need for compensating a producer depends on the combined electricity generation profile of all intermittent renewables. Fig. 2 depicts a load duration curve (solid black line), which is determined by ordering the hourly supply of electricity over a period of time (e.g. each hour of one year) from highest to lowest.

In the absence of intermittent renewable energy, the dispatchable capacity needed to ensure the security of supply is equal to the maximum load. When intermittent renewable energy

[2]Intermittent power stations impose no operational costs of producing electricity, whereas most dispatchable power plants do, mainly because of their fuel costs. This creates a merit order between the dispatchable and intermittent technologies (Oliveira, 2013).

[3]A capacity payment compensates an electricity producer for the capacity it has available and provides a revenue stream in addition to revenues generated by the sale of electricity.

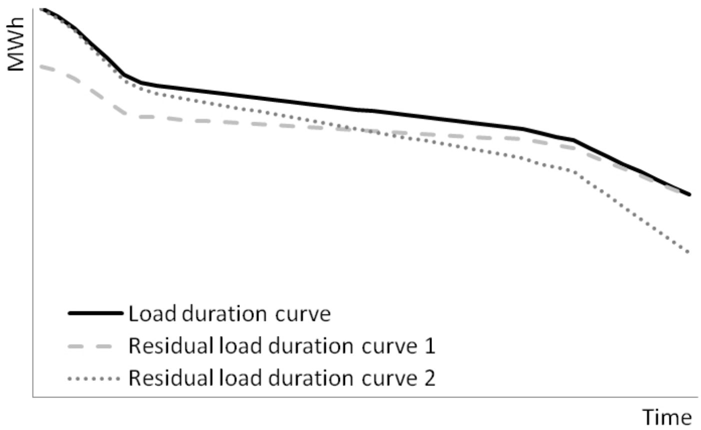

Figure 2: Load duration curve (in black) and two example of residual load duration curves (in grey).

sources are present, conventional power plants face a new load duration curve which is net of the energy generated by the intermittent renewables: the residual load duration curve or net load (van Kooten, 2010). Two residual load duration curves are shown in Fig. 2. In the first case (residual load duration curve 1), the residual load duration curve is flatter than the original curve. This implies that some of the dispatchable capacity becomes redundant as it is no longer needed to ensure the security of supply, hence avoiding or limiting the need for capacity payments. This need will depend on how dispatchable power plants need to adjust their production of electricity in response to the deployment of intermittent energy. In the second case, the residual load duration curve is steeper than the load duration curve. The maximum residual load faced by conventional power plants is unchanged compared to the base case, although the total quantity of power to be generated by dispatchable power stations is reduced. Capacity payments may be required to ensure that enough dispatchable capacity remains online in the future.

Combining the cost created by the intermittent characteristic of some renewable energy forms to the ability to deliver power during high prices hours, a valuable intermittent power station is thus a power station which produces electricity during high prices hours and which limits the need for mechanisms to guarantee the security of supply.

The deployment of intermittent renewable energy also creates additional costs (Hiroux and

Saguan, 2010). For example, the cost of balancing the system in the short-term is likely to increase when intermittent renewables are deployed as a result of more frequent ramping-up and down of base-load power plants (Lund, 2005). These costs have been found to be minimal when compared to the economic impact of reducing the quantity of electricity produced by conventional power plants (Hirth et al., 2013; Lamont, 2008) and are therefore not taken into account here.

3. Numerical analysis

The effectiveness of specific policy instruments at facilitating the deployment of valuable intermittent renewables is measured in the following numerical analysis. Common policy instruments include the feed-in tariff, the feed-in premium and the quota system.

3.1. Setting of the numerical analysis

The setting of the numerical analysis is deterministic. Data on power prices, gross electricity consumption and wind generation has been collected for West Denmark for 2011 and 2012 from Energinet (2013).

West Denmark is an interesting case because its geographical area is limited in size and wind power already contributes significantly to the supply of electricity[4]. In fact, West Denmark has deployed wind power to such an extent that the production of electricity from the extant wind turbines sometime exceeds the local demand for electricity and this excess electricity needs to be exported. In addition, Denmark is mostly thermal based and does not have large-scale storage systems that can be used to mitigate the intermittency issue of its wind turbines (van Kooten, 2010). Therefore, the ability of the country to integrate wind power to a large-scale is weak (Lund, 2005), albeit flexibility can be achieved by tapping into the nearby Nordic hydro-power dominated system (Jacobsen and Zvingilaite, 2010).

Denmark has adopted ambitious renewable electricity targets for the future. With a limited potential for hydro and increased biomass use (Lund, 2007), wind and solar power are the most mature technologies available to increase the country's share of renewable electricity.

[4] 37% of the electricity produced in West Denmark came from wind in 2012 (Energinet, 2013).

	Thermal plant
Capacity (MW)	3,592.50
Electricity production (TWh)	26
Capacity factor (%)	41
Average sale price (Euro/MWh)	48
Capital costs (Euro/MW)	223,000
Operational costs (Euro/MWh)	17

Table 1: Characteristics of the thermal power plant used in the numerical analysis. All numbers are caculated for the 2011-2012 period.

For the numerical analysis the gross electricity consumption in 2011 and 2012 is assumed to be supplied by two power plants: a thermal power plant and a wind farm. The economic characteristics of the thermal power plant are given in Table 1.

The capacity of the thermal power plant corresponds to the largest residual load during the period considered. The production of electricity is calculated as the difference between the demand for electricity and the supply of electricity from all wind farms. In the setting of this numerical analysis, the thermal power plant only produces power if there is a need for it and power prices are at least equal to the operational costs[5]. The average sale price is obtained by comparing the production of electricity from the power plant to the spot price in the hours when electricity is produced. Assuming operational costs based on Lazard (2013), the capital costs can be estimated with:

[5]About 1% of all electricity consumed in West Denmark is not supplied by the wind farm and is produced at a price lower than the operational costs of the thermal power plant. In the model, this electricity is not produced by either the existing wind farm or the thermal power plant and shocks on production will not show in the results of the numerical analysis.

	Solar	Wind
Levelized costs (Euro/MWh)	69	60
Installed capacity (MW)	1.8	1
Power production 2011-2012 (MWh)	4,807	4,807
Capacity factor (%)	27.3	14.9

Table 2: Characteristics of the solar power station and of the wind farm used in the numerical analysis. The levelized cost data is based on Lazard (2013).

$$\text{Capital costs/MW} = \frac{(\text{Av. sale price - Operational cost}) \cdot \text{Power production}}{\text{Capacity}} \tag{3}$$

The capital costs are considered to be fixed per MW of installed capacity.

Two projects are available for West Denmark to increase its share of electricity from new renewables: a wind farm located in Esbjerg and a solar power station located in Sønderborg. The approaches implemented to estimate the electricity production profiles of these power stations are described in the appendix, and both production profiles over a week in April 2012 are illustrated in Fig. 3. The comments and analysis provided thereafter only pertain to these specific wind and solar patterns and should not be taken as valid for all future wind and solar power stations in Denmark.

The key characteristics of these power stations are summarized in Table 2.

The capacity of both power stations is adjusted such that they produce the same amount of energy over the time period considered. The levelized costs of both plants are estimated based on Lazard (2013) and on a direct cost basis, the cost of solar power exceeds this of wind power by nearly 30%. Such comparison however ignores the value of energy (Jaegemann, 2014).

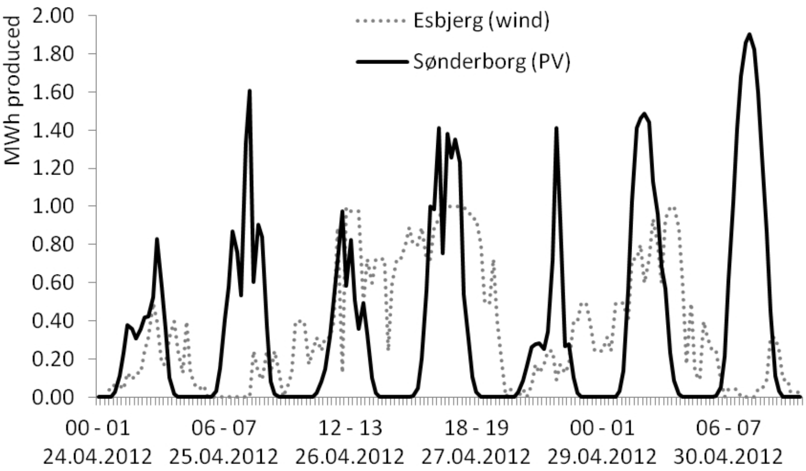

Figure 3: Illustration of the estimated production profiles of both power stations during the last seven days of April 2012.

3.2. No policy instrument

In the absence of policy instrument, an intermittent power station's revenues are solely generated via the sale of electricity on the wholesale market. By scaling up the capacity of a single intermittent power station, hence assuming that all intermittent power stations have the same production pattern, earlier research (Lamont, 2008; Hirth et al., 2013) has shown that the marginal value of an intermittent power source declines as the intermittent technology penetrates the market. The reason for this decline is that the production of electricity from an intermittent power station displaces more expensive power from the system, in effect driving down the system price. This conclusion is important in the case of West Denmark; a geographically limited area in size with concentrated wind resources and high wind power penetration rates.

There is a negative correlation between market prices and production of electricity from the existing wind farms in West Denmark (estimated correlation of -0.25). The electricity production of the hypothetical wind farm is higly correlated with the extant intermittent electricity production (estimated correlation of 0.84), whereas the production of the solar power station is not (estimated correlation of -0.09). This difference in correlation implies that the solar power station should produce during hours with comparatively higher prices compared to the new wind farm. Confronting the estimated production pattern to the power prices shows that this is effectively the case. Further assuming that deploying these power stations would not affect the market prices, the solar power station would perceive a price of 47 Euro/MWh for the electricity it sells on average, which is to be compared with the average price of 39 Euro/MWh for the wind farm. The two power stations only produce electricity if power prices exceed the marginal cost of producing electricity[6], reason why the wind farm does not produce to its full potential (see Table 3).

The impact of building these power stations on the spot price is ignored for simplicity purposes[7]. At least in the short term, this simplification is likely to result in an overestimate of the spot prices obtained per MWh produced. However, this bias increases with the size of the power station; hence as long as the power stations are limited in size, the bias should remain small.

This average spot price can be used to calculate the net present value of investing in these power stations[8]. The net present value of investing in either power station is negative in the absence of some type of subsidy and these power stations are therefore unattractive financially.

Were these power stations nonetheless deployed, they would impact the economics of the thermal power plant. The indirect cost of deploying an intermittent power station is two folds. First, generating power during high residual load hours allows for a reduction of the dispatchable capacity needed to balance supply and demand of electricity, which contributes

[6]The marginal cost of producing electricity is set to zero for the wind and solar power station.

[7]Other papers investigate the impact of deploying intermittent power stations on the short and long term market prices. For example, MacCormack et al. (2010) and Hirth (2013) argue that electricity prices will be reduced as penetration levels of intermittent energy sources increases. Oliveira (2013) conclude that intermittency reduces the level of investment in capacity which leads to higher average electricity costs in the long term.

[8]For simplicity purposes, the plant lives of these assets are assumed to be two years and the investment costs are set equal to the quantity of electricity produced times the asset's levelized costs of energy. A discount rate of 5% is utilized.

	Solar	ΔThermal$^{\text{Solar}}$	Wind	ΔThermal$^{\text{Wind}}$
Av. market price (Euro/MWh)	47		39	
Electricity prod. (MWh)	4,807	-4,621	4,773	-4,096
Net present value (Euro)	-101,930		-99,128	
Thermal capacity (MW)		-0.21		0
Capacity factor (%)		-0.005		-0.006
Economic impact (Euro)		-97,628		-103,419
Intermittency cost (Euro/MWh)		21.13		25.25

Table 3: Economic characteristics of the solar power station, the wind farm and their impact on the economics of the thermal power plant in the absence of subsidy.

to lowering the total system cost. The solar power station produces electricity during the hour with the highest residual load, whereas the wind farm does not. Second, feeding intermittent electricity into the electric grid results in a reduction of the production from the dispatchable power plant. Here, the thermal power plant would need to curtail its production by 4,621 MWh and 4,096 MWh in the solar and wind case respectively. The difference between the production of electricity from the intermittent power stations and the amount of 'thermal' electricity curtailed is generated at times of prices not exceeding the marginal cost of producing power for the thermal plant and thus do not affect its economics. This effective reduction in electricity production will pressure the economics of the thermal power plant, because it will spread its fixed costs over fewer units of electricity.
The economic impact of deploying a power station on the economics of the thermal power plant can be measured with:

$$\text{Economic impact} = \frac{\text{Revenues} - \text{Costs}}{\text{Electricity curtailed}} \tag{4}$$

where costs are given by:

$$\text{Costs} = (\text{Capacity} \cdot \text{Capital costs}) + (\text{Electricity production} \cdot \text{Operational costs}) \tag{5}$$

Dividing the economic impact by the quantity of electricity curtailed gives the indirect cost of deploying the solar power station. Here, the intermittency cost of deploying an intermittent power station amounts to 21.13 Euro/MWh of lost production[9] and to 25.25 Euro/MWh in the case of the wind farm. The following paragraphs will demonstrate that current policy instruments typically disregard this category of cost, which can nonetheless be substantial. The indirect cost of intermittency depends on the characteristics of the system. Results are likely to differ, for example in a hydro-dominated system where capital intensity of the technology is the norm (e.g.: Norway) and where the intermittency of some technologies can more easily be compensated for (van Kooten, 2010).

Since the net present value of investing in either power station is negative in the absence of subsidy, some type of policy instrument will be needed if West Denmark wants to increase its share of electricity from renewable energy sources.

3.3. Feed-in tariff

A first option to facilitating the deployment of intermittent renewable energy is a feed-in tariff (FiT). A FiT guarantees a price set in advance for each MWh fed into the grid for a fixed period of time (Couture and Gagnon, 2010). Electric utilities have the obligation to purchase the electricity produced (Finon et al., 2002). Often, different tariffs are set to reflect the disparity in levelized costs of various intermittent renewable technologies. FiTs have been very effective in countries offering generous schemes, resulting in the rapid deployment of intermittent capacity, mostly because this type of policy instrument mitigates price and demand risks by design (Green and Yatchew, 2012). Since prices are guaranteed, the revenues of the plant owner are totally independent from the wholesale energy market prices.

[9] This amount is required to ensure that the economics of the thermal power plant remains unchanged if the solar power station is deployed.

In the scope of the numerical analysis, a technology specific FiT can be put in place to make an investment into the solar PV power station or in the wind farm financially attractive. A plain levelized cost of energy analysis indicates that FiTs exceeding 60 Euro/MWh and 69 Euro/MWh are needed to make the net present value of investing in the wind farm, respectively the solar power station, positive.

The net policy cost C^{FiT} of building either project is equal to the difference between the wholesale power price P_h^{market} in an hour and the price of the FiT P^{FiT}, multiplied by the quantity of power q_h generated in that hour for each hour of 2011 and 2012:

$$C^{FiT} = \sum_h (P^{FiT} - P_h^{market}) \cdot q_h \tag{6}$$

The net policy cost per MWh, calculated as the net policy cost divided by the quantity of energy generated, amounts to 21.58 Euro/MWh of wind power and to 21.89 Euro/MWh of solar power (see Table 4). This seemingly limited difference in policy costs between the wind and solar case results from the ability of the solar power station to produce electricity in higher priced hours. Despite this advantage, solar power nonetheless remains costlier than wind power on a direct cost basis.

In addition, both plants will create an indirect cost related to their intermittency. This cost is unchanged as compared to the *no policy* case[10]. The full cost of forcing one of the projects into the grid can be calculated as:

$$\text{Full cost} = \frac{\text{Policy cost} + \text{Economic impact}}{\text{Electricity production}} \tag{7}$$

and the full cost of forcing the wind farm into the grid reaches 43.09 Euro/MWh, whereas this cost is of 42.20 Euro/MWh for the solar power station. In words, the electricity from this

[10]This result is a likely implication of a limitation of the model used. If the power station generates electricity during hours of positive residual load and power prices do not exceed the marginal cost of producing power for the thermal plant, some other plants will have to curtail their production. This effect will not show in the results. See footnote 5.

	Solar	$\Delta\text{Thermal}^{\text{Solar}}$	Wind	$\Delta\text{Thermal}^{\text{Wind}}$
FiT (Euro/MWh)	69		60	
Electricity prod. (MWh)	4,807	-4,621	4,807	-4,096
Policy cost (Euro)	105,243		103,751	
Policy cost (Euro/MWh)	21.89		21.58	
Thermal capacity (MW)		-0.21		0
Capacity factor (%)		-0.005		-0.006
Economic impact (Euro)		-97,628		-103,419
Intermittency cost (Euro/MWh)		21.13		25.25
Total cost (Euro/MWh)	42.20		43.09	

Table 4: Economic characteristics of the solar power station, the wind farm and their impact on the economics of the thermal power plant under a FiT system.

particular solar power station is cheaper on a full cost basis than the electricity generated by this particular wind farm. These results are summarized in Table 4.

Under a FiT, a power station owner has no incentive to react to market signals. Even if power prices fall below zero, the production of electricity will be rewarded at a fixed price. For this reason, the wind farm produces more under the FiT than under a *no policy* case. These extra 35 MWh of wind power will need to be exported at a negative price, further pressuring the region's electricity export capacity and increasing the cost of deploying wind power in West Denmark.

To be efficient, in the sense that a FiT delivers the most valuable energy first, a FiT requires to administratively define what the value of energy is. This process can prove to be challenging given the uncertainty underlying the cost of the technology, the future energy supply and the wind and solar conditions to name a few. Hence, designing an efficient FiT appears to be nearly impossible. An inefficient FiT will facilitate the deployment of intermittent renewable energy as long as it is generous, although a fraction of it might be of little value to the system. Consequently, a FiT appears inappropriate to efficiently facilitate the deployment of valuable intermittent renewable energy.

Relaxing the deterministic assumption for a more realistic and stochastic setting; the ability of the solar power station to reduce the quantity of dispatchable capacity needed to ensure the security of supply is no longer guaranteed. However, deploying power stations which produce electricity during times of high prices increase the chances that the system can reduce the quantity of dispatchable capacity to ensure the security of supply. Therefore, the implication of the numerical analysis that intermittent power stations delivering at times of high prices are most valuable should remain valid.

3.4. Feed-in premium

A second option to facilitating the deployment of intermittent renewable energy is the feed-in premium (FiP). A FiP rewards each unit of electricity fed into the grid with a constant premium on top of the wholesale electricity market price. Similar to a feed-in tariff, a FiP can be differentiated across technology types.

Performing a similar numerical analysis as under the feed-in tariff, the solar power station requires a FiP exceeding 21.72 Euro/MWh to incentivize an investor to finance this power station. Similarly, at least 21.20 Euro/MWh is required in the case of the wind farm. The difference between these numbers and those presented for the feed-in tariff case can be explained as follow. The costliest electricity from a policy perspective in the feed-in tariff case is the electricity generated when power prices are negative. Here, no power will be produced when the price perceived by the plant owner (power price + premium) does not exceed the marginal cost of producing power. This leads to a reduction in the net policy cost of deploying intermittent renewable energy. This benefit is however partially offset by the reduction in the quantity of electricity generated by the power station, resulting in an increase in the power station's LCOE and consequently of the quantity of support per MWh needed. The impact on the thermal power plant is unchanged compared to a feed-in tariff

	Solar	$\Delta\text{Thermal}^{\text{Solar}}$	Wind	$\Delta\text{Thermal}^{\text{Wind}}$
FiP (Euro/MWh)	21.72		21.20	
Electricity prod. (MWh)	4,807	-4,621	4,794	-4,096
Policy cost (Euro)	104,411		101,627	
Thermal capacity (MW)		-0.21		0
Capacity factor (%)		-0.005		-0.006
Economic impact (Euro)		-97,628		-103,419
Intermittency cost (Euro/MWh)		21.13		25.25
Total cost (Euro/MWh)	42.02		42.77	

Table 5: Economic characteristics of the solar power station, the wind farm and their impact on the economics of the thermal power plant under a FiP system.

case and the total cost of forcing the solar power station into the system thus reaches 42.02 Euro/MWh and this of the wind farm 42.77 Euro/MWh. Again, the solar power station appears slightly more valuable on a full cost basis.

Compared to a feed-in tariff system, the FiP creates an incentive to produce electricity when it is needed most (Hiroux and Saguan, 2010; Gawel and Purkus, 2013) because the plant owner total remuneration will rise with increasing electricity prices. Everything else being equal, investors will favor projects which deliver electricity when prices are high, hence facilitating the integration of intermittent renewable energy into the electricity system (Langniss et al., 2009). However, this type of policy instrument does not reflect the intermittency cost and the risk of investing under a FiP is comparatively higher (Couture and Gagnon, 2010) since future prices are uncertain. Investors are therefore likely to require a higher premium to compensate for this risk as compared to a feed-in tariff case.

3.5. Quota system

A third option is a quota system (QS). A QS is a quantity-based policy instrument where the policy maker sets how much renewable energy needs to be delivered (for instance as a share of total energy produced) (Menanteau et al., 2003). Operators can either meet their target by generating the power themselves or buy green certificates from specialized renewable energy generators or other operators which have exceeded their target (Finon et al., 2002). The price of the certificate depends on how much supply is available in the market and an oversupply of renewable electricity will drive the certificate cost to zero, for instance if wind power gets competitive.

Both revenue streams (wholesale market price and price of the green certificates) are uncertain and the financial risk of investing in intermittent power under a QS scheme is higher (Lesser and Su, 2008) than under the two price-based policy instruments described previously. This type of policy instrument is deemed to be more efficient than price-based instruments, because the least costly technology will be built first (Couture and Gagnon, 2010) and more efficient producers are favored (Lesser and Su, 2008).

In a deterministic setting and if only one technology is considered, the situation under a QS and a feed-in premium is comparable. If both technologies are considered, the cheapest technology on a direct cost basis will be built first. However, considering the full cost of energy, a quota system is not necessarily efficient. The numerical analysis shows that a QS would facilitate the deployment of the wind farm when the solar power station has a higher value.

4. Alternative system - multiplicative premium

The three policy instruments investigated above; the feed-in tariff, the feed-in premium and the quota system are based on the direct cost of energy. Of these three, the feed-in tariff is the least efficient at deploying intermittent renewable energy as it offers little guarantee that the most valuable intermittent energy projects are built first. The two other policy instruments already better align incentives and market needs. Of these, the quota system is the most efficient since the market decides which technology is to be built and where. Yet, these instruments are based on the direct cost of energy and they do not take the cost of intermittency into account.

A question here is on whether it is possible to design an incentive scheme which would facilitate the deployment of *valuable* intermittent energy. Hence, the aim is not to maximize the production of intermittent electricity, nor to smooth out the production of intermittent power but rather to deliver the most valuable power stations for the system, consequently minimizing the total electricity system cost. To the knowledge of the author, no method is universally recognized on how the cost of intermittency can easily and reliably be measured and no attempt is being made here to suggest one. Rather, a new policy instrument which may increase the chances of deploying only valuable projects will be suggested.

Deploying intermittent energy sources producing electricity at times of high prices leads both to higher revenues for plant owners and to higher chances that some of the dispatchable capacity needed to ensure the security of supply can be decommissioned. The first implication is that the prices faced by an intermittent power station owner need to be tied to wholesale market prices (Jaegemann, 2014; Gawel and Purkus, 2013), hence ruling out a feed-in tariff type instrument. Ideally, an intermittent power station owner should not have any incentive to produce electricity when market prices become negative (Hiroux and Saguan, 2010), hence ruling out additive policy instruments[11]. In addition, there is a benefit in forcing the production of electricity during high residual load[12], because only the production of intermittent power during peak load can lead to a reduction in the capacity of dispatchable power needed to balance the market. A possible approach in achieving these goals simultaneously is by increasing the variation in prices seen in the wholesale electricity market. A multiplicative premium would be such an option. A multiplicative premium

[11] Both the feed-in premium and the quota system are additive since the plant owner receives a revenue in addition to the market price.

[12] In a repeated game, producing electricity during high residual load hours would reduce this load and depress the prices in those hours. This would change the residual load duration curve and give rise to new high residual load periods when new intermittent power would be the most valuable and prices the highest.

	Solar	$\Delta\text{Thermal}^{\text{Solar}}$	Wind	$\Delta\text{Thermal}^{\text{Wind}}$
Multiplicative premium	1.46		1.54	
Electricity prod. (MWh)	4,807	-4,621	4,773	-4,096
Policy cost (Euro)	104,027		101,162	
Policy cost (Euro/MWh)	21.64		21.19	
Thermal capacity (MW)		-0.21		0
Capacity factor (%)		-0.005		-0.006
Economic impact (Euro)		-97,628		-103,419
Intermittency cost (Euro/MWh)		21.13		25.25
Total cost (Euro/MWh)	41.95		42.86	

Table 6: Economic characteristics of the solar power station, the wind farm and their impact on the economics of the thermal power plant under a multiplicative premium.

would imply from the policy maker to set a multiplicative coefficient which would multiply the market prices for a given year[13]. Generating electricity in periods of high prices would generate significant revenues, thus forcing the plant owner to deploy intermittent assets which produce at times of high prices and high residual load.

Applying this instrument to the numerical case shows that the solar power station becomes attractive for a lower coefficient than the wind farm (see Table 6). The policy instrument rewarding the production of electricity during high prices hours more than the spot price does, the solar power station becomes financially attractive before the wind farm.

The electricity production of the wind farm is lower under the multiplicative premium than

[13]One could imagine mimicking the feed-in tariff by setting a multiplicative premium for a year and all intermittent projects built during that year would perceive this premium for a fixed duration of time. Projects built the following year would receive a lower multiplicative premium in order not to overcompensate new entrants with lower power generation costs, and so on.

under any other policy instruments. The reason for this difference is that the wind farm would rather curtail its electricity production instead of producing when power prices are negative. This incentive not to produce when prices are negative lead to a reduction of the net policy cost. In that sense, this type of policy instrument would align incentives and market needs, hence making the multiplicative premium efficient.

It has to be noted that the price risk for investors created by the multiplicative premium is higher than under a feed-in premium since the range in prices faced by the investor is larger. However, a multiplicative premium is likely to be safer than a quota system. The prices of green certificates can drop to zero, whereas electricity prices are unlikely to be at zero or negative for a prolonged period of time.

A disadvantage of a multiplicative premium is that it would not facilitate the deployment of costly, non-mature technologies such as wave power, which would require additional support to become attractive to investors. Hence, if the policy objective is to facilitate the deployment of new technologies, a feed-in tariff is perhaps more appropriate than a multiplicative premium.

5. Conclusion

A valuable intermittent renewable energy source is a source of energy which requires little financial support and which allows for an effective reduction of the quantity of thermal power needed to balance supply and demand of electricity at all times.

Given the comparatively high cost of intermittent renewables, feed-in tariffs, feed-in premiums and quota systems have been implemented to facilitate the deployment of intermittent renewables. These three specific policy instruments change the prices faced by investors and plant owners. If not designed properly, a feed-in tariff can lead to the concentration of intermittent energy during periods of low residual supply and create situations where capacity payments are needed to ensure that supply is sufficient at all times. Feed-in premiums and quota systems are more efficient at delivering renewable energy on a direct cost basis as these policy instruments are based partly on the spot price. Yet, these two policy instruments ignore the intermittency cost created by the deployment of intermittent renewable energy.

A new policy instrument, a multiplicative premium, is suggested in this study. This policy instrument rewards power stations which produce during high prices hours, forcing the deployment of intermittent power station which deliver energy during these hours. This type of policy instrument may therefore be more efficient at delivering valuable projects than existing policy instruments. A multiplicative premium would be uniform to all technologies ensuring administrative ease and providing more security to investors than a quota system.

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Appendix - Electricity Production Pattern

Each wind turbine has a cut-in wind speed $v^{\min}$ under which it does not generate power. Past this wind speed, the electricity production increases rapidly with wind speed v until the wind turbine reaches its maximum capacity C. If the wind speed increases past a cut-out speed $v^{\max}$, the blades of the wind turbine will have to be pitched such as to prevent damage to the structure of the wind turbine and the electricity production falls to zero. In between the cut-in and cut-out wind speeds, the electricity production is a function of the area swept by the wind turbine A, a scaling factor f, the density of air ρ (assumed to be constant at 1.225 kg/m^3) and the wind speed v measured in meter per second (m/s). The quantity of electricity q produced at time t by a wind turbine was best approximated in this study by the following equation:

$$q_t^{\text{wind}} = \begin{cases} 0 \text{ if } v < v^{min} \\ \frac{1}{2}\rho A v^3 f \text{ if } v \leq 11 \\ 2200 + (v - 11) \cdot 400 \text{ if } 11 < v \leq 12 \\ 2600 + (v - 12) \cdot 320 \text{ if } 12 < v \leq 13 \\ 2820 + (v - 13) \cdot 160 \text{ if } 13 < v \leq 14 \\ 2980 + (v - 14) \cdot 20 \text{ if } 14 < v \leq 15 \\ 3000 \text{ if } 15 < v \leq v^{max} \\ 0 \text{ if } v^{max} < v \end{cases} \tag{8}$$

The scaling factor f is used to match the estimated power curve of a wind turbine as closely as possible to the power curve estimated by the wind turbine manufacturer. In this study, the power curve reflects this of a Vestas V90-3.0 MW wind turbine with a cut-in wind speed of 3.5 m/s and a cut-out wind speed of 25 m/s.

Historical hourly data on wind speed were collected from *www.weatherspark.com*. These wind speeds are corrected for height difference between the anemometer height and the hub height of the wind turbine using the approximation suggested in Oswald et al. (2008):

$$\text{Height correction} = \frac{ln(\text{hub height / grass height})}{ln(\text{anemometer height / grass height})} \tag{9}$$

The electricity production of the solar power station is approximated by:

$$q_t^{\text{solar}} = i_t \cdot A \cdot e \tag{10}$$

where i is the quantity of direct, diffuse and reflected solar radiation hitting a solar panel in Watt per square meter (W/m^2), A is the area covered by the solar field in m^2 and e is the efficiency of the solar panel. A SunPower X21-345 is used in this study, which has an efficiency of 21.5%. Hourly historical data on solar radiation were generously provided by $www.soda-is.com$ and are optimised for solar panels oriented south and with a tilt of 40$^{\text{o}}$.

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