



# NOTA DI LAVORO

109.2013

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Italy: A Real Option  
Approach**

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By **Tommaso Biondi**, Sinloc, Sistema  
Iniziativa Locali S.p.A  
**Michele Moretto**, Department of  
Economics and Management, University  
of Padova, Fondazione Eni Enrico  
Mattei and Centro Studi Levi- Cases

## Energy: Resources and Markets

Series Editor: Giuseppe Sammarco

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By Tommaso Biondi, Sinloc, Sistema Iniziative Locali S.p.A  
Michele Moretto, Department of Economics and Management,  
University of Padova, Fondazione Eni Enrico Mattei and Centro  
Studi Levi- Cases

#### Summary

Over the past three years Italy has witnessed a rapid growth in the photovoltaic energy market, followed by an equally sudden decline when the government decided to reduce the incentives. This sharp change in the trend of the market calls into question the achievement of Grid Parity and the possibility that the market is able to develop independently. Starting from the standard Grid Parity Model, widely used for the photovoltaic (PV) market, we internalize the uncertainty surrounding both the energy price and PV module costs, to forecast the dynamics of the Italian PV market. We show that these sources of uncertainty can delay the Grid Parity timing of several years compared to current forecasts, well describing the current market situation.

**Keywords:** Photovoltaic Market, Grid Parity

**JEL Classification:** O3, O31, O32

*Address for correspondence:*

Michele Moretto  
University of Padova  
via del Santo 33  
35100 Padova  
Italy  
E-mail: [michele.moretto@unipd.it](mailto:michele.moretto@unipd.it)

# Solar Grid Parity Dynamics in Italy: A Real Option Approach

Tommaso Biondi\*      Michele Moretto†

November 11, 2013

## Abstract

Over the past three years Italy has witnessed a rapid growth in the photovoltaic energy market, followed by an equally sudden decline when the government decided to reduce the incentives. This sharp change in the trend of the market calls into question the achievement of Grid Parity and the possibility that the market is able to develop independently. Starting from the standard Grid Parity Model, widely used for the photovoltaic (PV) market, we internalize the uncertainty surrounding both the energy price and PV module costs, to forecast the dynamics of the Italian PV market. We show that these sources of uncertainty can delay the Grid Parity timing of several years compared to current forecasts, well describing the current market situation.

## 1 Introduction

Year 2011 was pivotal for the photovoltaic (PV) market in Italy. With about 9 Giga watts of new installations, the Italian photovoltaic capacity has grown by 430% compared to 2010. This was the result of a decrease in the cost of modules and, in particular, by the introduction of an incentive mechanisms by the Italian Government, the Feed In Tariffs (FIT), kept forcedly high from 2005 till 2012<sup>1</sup>. For this reason, the past development of the PV market is giving way to a high degree of uncertainty in the future. In the coming years we expect a phase out of the FIT, able to drive the Italian energy system towards the competitiveness of photovoltaic energy. This competitiveness, called Grid Parity, is defined as the intersection between the electricity price and the unit cost of a plant and it represents the break-even point of the investment. Grid Parity, which is gaining more and more attention from photovoltaic industry professionals, is considered as the appropriate time for a cost-neutral investment and it represents the final phase of the expansion of this technology.

However, the Grid Parity provides only a partial view of the problem. The break-even analysis behind the Grid Parity does not take into account two important aspects of the decision to invest in a PV system: the irreversibility of the choice and the uncertainty of some key variables. In the specific, this paper, by using the Real Option Approach, tries to internalize both the uncertainty related to the electricity price and the energy generation cost to assess the effect that these variables have on the optimal investment time.

Internalizing these sources of uncertainty results in a delay of the PV Grid Parity timing with respect to the current forecasts that place it around 2014. In particular, when the high level of uncertainty which is actually surrounding the market is taken into account, Grid Parity is far from being achieved and it can be moved forward by ten years. We show that this result is robust to variations of some key parameters that affect the analysis.

The remainder of the paper is organized as follows. Section 2 discusses the related literature. Section 3 presents empirical evidence, drawn from Italian data, of the dynamics of both the

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\*Sinloc, Sistema Iniziative Locali S.p.A., Padova, Italy. Email: [tommasobiondi@me.com](mailto:tommasobiondi@me.com)

†Department of Economics and Management, University of Padova, Fondazione Eni Enrico Mattei and Centro Studi Levi-Cases. Corresponding address: via del Santo, 33 35100 Padova, Italy. Email: [michele.moretto@unipd.it](mailto:michele.moretto@unipd.it)

electricity price and the cost of energy. Section 5 models the value of a PV system in term of Grid Parity and illustrates our main findings through numerical calibrations. Section 6 concludes.

## 2 Discussion of the related literature

Grid Parity is defined as the time when the unit cost of photovoltaic energy will reach the electricity price. The dynamic model for Grid Parity is based on the historical negative relationship between two trends: the decreasing PV electricity generation costs and the electricity price showing an increasing path over time. The Grid Parity goal is considered as the final phase of PV electricity expansion, representing cost-competitiveness of solar power generation systems. Nowadays, PV power generation is already competitive in many off-grid installations, especially in developing countries, while global competitiveness is expected until 2020 (Acanfora and Alcor 2011, Salvadores and Keppler 2010b).

Renewable energy technologies for producing electricity have received greater attention in recent years, due to the rise of fossil fuel prices and concern for greenhouse gases emissions and climate change. Following the important growth of the green-economy and the astonishing boom of photovoltaic power generation systems, Solar Grid Parity has become a large debated issue. Despite this growing interest – we can find many newspapers’ articles speaking about Grid Parity – there is still no much literature available on this. The major references have to be found in the roadmaps of the global energy associations, like the IEA (International Energy Agency), the EPIA (European Photovoltaic Industry Association) and the IRENA (International Renewable Energy Agency), or in some research papers commissioned by the biggest PV module producers and in few specific works commissioned by the governments of some world regions.

A first study on Grid Parity, in chronological order, can be found in Lorenz et al. (2008), which brought out several important issues of great interest at the present time. This article forecasted the high level of competitiveness the market of module producers is affording today, underlying the need to “move production to low-cost countries to maintain a stable market share”. This contribution also depicted the need for a sustainable regulatory framework – a necessary tool on the way to PV competitiveness – able to boost market development without doping the PV sector<sup>2</sup>.

Breyer and Gerlach (2010) is the first academic study on Grid Parity. Commissioned by Q-Cells in 2009, the authors make a first global overview on Grid Parity Event Dynamics. The aim of the paper is to define the gradual achievement of Grid Parity in different countries, according to their solar irradiation and to the average value of electricity prices in their domestic market. Italy was considered to be the first to reach Grid Parity in 2010 (high solar irradiation, high electricity prices), followed by Spain, Portugal and Cyprus. Outside Europe, California was expected to reach Grid Parity in 2012, while almost all the central and southern States of the US were supposed to reach the goal before 2020. It is one of the first work to apply learning curves to the Levelised Cost Of Electricity (LCOE), in order to explain the decrease in PV production costs.

Acanfora and Alcor (2011, 2012) set the goal of Grid Parity before 2020 for all European countries, where (again) Italy is indicated as the first to reach it. The analysis by Salvadores and Keppler (2010b) presents the same results. The commercial development of PV plants is divided into three different phases, within the interval 2010 - 2020, when many countries, characterized by good solar resources and high conventional electricity prices, will reach the Grid Parity.

Apart from these works, which provide a comprehensive vision of the phenomenon, there are a few studies focusing on Grid Parity timing in specific countries. Bhandari and Stadler (2009), compute the average cost of a PV power generation system in the region of Cologne (Germany), for both residential consumers and utilities, and compare them to the respective local electricity prices. Considering (the higher) electricity prices for end-users, Grid Parity will be reached between 2013 and 2014. However, taking into account (the lower) wholesale electricity

prices, Grid Parity shifts to 2023. They also present some sensitivity analysis with respect to the PV module economic lifetime. While the standard economic lifetime is placed between 20 and 30 years – 25 are the most-used benchmark – the authors stress the analysis with a 35 to 40 years production period. This increase in the production period, applied to the wholesale Grid Parity model, reduces Grid Parity to 2019 and 2017 respectively. Mitscher and Rutter (2012), make a widespread analysis of the Brazilian case. In particular, the authors stress the need for lower interest rates to reach the Grid Parity. Focusing on the problem of current credit cost on the Brazilian market, they show how a lower cost of credit can be sufficient to achieve Grid Parity in several Brazilian cities, even with the current PV system prices. Further, Ong et al. (2012), concentrate their attention on the United States residential PV market. They perform an interesting sensitivity analysis based on the rate of solar radiations. They found that the current break-even price varies more than a factor of 10 even though the solar resource varies by less than a factor of 2. In line with these findings, they show that only a part of the residential users will have the necessary combination of good solar access and attractive financing options to really consider to invest in a PV system.

Yang (2010) stress the fact that the cost-effectiveness may not guarantee commercial competitiveness. Looking at the case of the Solar Heating Water market in Hawaii, where this technology is considered to be cost-competitive, Yang shows that the break-even point has not been a powerful driver for market expansion. He sets the need of further government interventions to exploit the untapped potential of the solar PV market.

The works that is most closely related to ours is Belien et al. (2013). The authors derive the “the best time to invest” in a PV panel by a profit maximizing investor in Flandres. Even if they compare their work with some Grid Parity studies, they outline how their model is different from a standard Grid Parity approach. First, Grid Parity is not a profit-maximizing model. It focuses only on the break-even point between electricity prices and PV costs. Second, considering subsidies in the analysis, they internalize government choices over the future values of the FIT. Grid Parity should focus on unsubsidized prices to end-users, without taking into account any form of incentive. The authors’ results of an optimal investment time around 2012 are in line with the model structure. The power generation plant must be installed as early as possible, given that future FITs are uncertain and expected to end quickly.

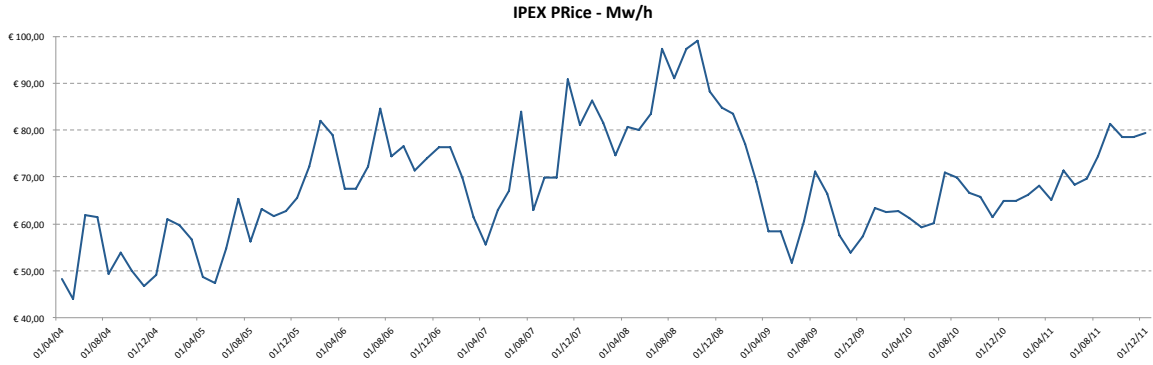
Finally, in the same vein, the “Solar Energy Report” by the Politecnico di Milano (2012), sees the Grid Parity as a key point for the determination of a gradual depletion of incentives taking account of the specificities of the different types of plant.<sup>3</sup> The Report presents a non-standard formulation of Grid Parity timing. It is not only the time at which electricity prices and the unit cost of PV systems equals, it is viewed as the time in which the investment in PV plants – without incentives – will give a positive Net Present Value.

### 3 Electricity Prices in Italy

Electricity is usually considered as a “commodity”, but it presents some peculiarities that differentiate the behavior of its price from the price all other commodities. The most important difference is probably the non-storability. Electricity cannot be physically stored in a direct way and production and consumption have to be continuously balanced. Therefore, supply and demand shocks cannot be easily smoothed out and they have a direct effect on equilibrium prices. Furthermore, electricity is a primary commodity, so its demand is highly inelastic. These features, coupled with the fact that the price is highly weather dependent, contribute to explain the observed high volatility.<sup>4</sup>

We use 93 monthly data on Italian electricity prices (PUN, Prezzo Unico Nazionale), starting from April 2004, the first operating month of the Italian Power Exchange (IPEX), to December 2011.

As we can see from Figure 1, after three years of growth, in 2007 we can notice the first



**Figure 1:** IPEX Price, April 2004 - December 2011 (Monthly data from [www.gse.it](http://www.gse.it))

decline of the PUN. This is primarily due to the relationship between electricity prices and Brent prices. Although the level of oil prices in 2007 is steadily increased, this growth has been compensated by two different phenomena: the significant strengthening of the Euro against the U.S. Dollar and the delay with which the variations in Brent prices reflect on Italian electricity prices<sup>5</sup>. There is some evidence of a lagged relationship between oil prices and electricity prices, due to the contractual structure of fuel supply. Furthermore, electricity prices depend on the marginal class of power generation plants – i.e. Natural Gas (NG) power plants. Given that the cost structure of NG power plants is dominated by NG fuel cost, their strong correlation with oil prices reflects on electricity prices. In line with this lagged relationship, we can notice peak values of the PUN in 2008, followed by a strong price decrease in 2009. This last phenomenon is the result of the decrease in fuel prices and electricity consumption caused by the economic crisis – in 2009 the PUN reaches the lowest values since 2005. In 2010, despite a strong increase in crude oil prices, the PUN has maintained its lower levels, with a moderate increase at the end of the year. Finally, the graph shows an important upward trend in 2011. This growth is partially mitigated by a persistent level of overcapacity, which has been boosted by the important increase in photovoltaic plants.

Denoting by  $P_t$  the IPEX price we test whether it follows a Geometric Brownian motion (GBM) and then the appropriate parameter values will be calculated. The GBM is a simple parsimonious process, which requires only the computation of two parameters (drift and volatility) to be fitted, i.e.<sup>6</sup>:

$$dP_t = \alpha_P P_t dt + \sigma_P P_t dB_t \quad \text{with } P_{t_0} = P_0 \quad (1)$$

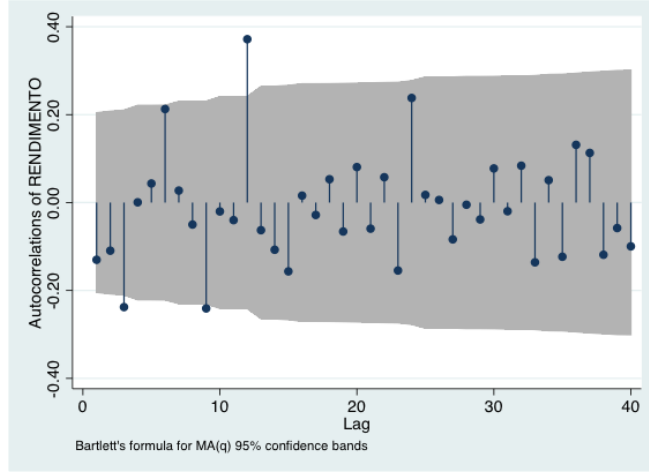
where  $dB_t$  is the increment of a standard Wiener process (Brownian motion),  $\alpha_P$  is the drift term and  $\sigma_P$  the instantaneous volatility of the process. Applying Itô's formula, we rewrite the basic stochastic equation (1) as follows:

$$d \ln P_t = \left( \alpha_P - \frac{\sigma_P^2}{2} \right) dt + \sigma_P dB_t \quad (2)$$

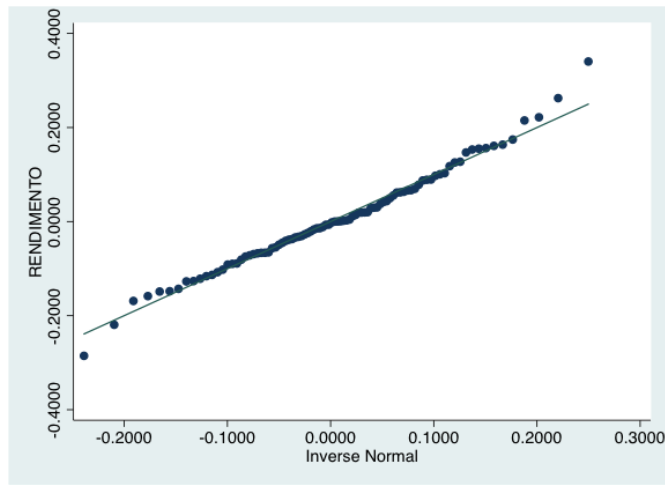
where the increments of  $\ln P_t$  are normally independent identically distributed with mean  $\left( \alpha_P - \frac{\sigma_P^2}{2} \right) dt$  and variance  $\sigma_P^2 dt$ . Using STATA software we test the independence assumption by plotting the autocorrelations of the log returns  $r_t = \frac{\ln P_{t+1}}{\ln P_t}$ :

Figure 2 shows that we do not have significant autocorrelations till the 12<sup>th</sup> lag. All the other values are below the confidence interval. This is a usual behavior for electricity prices, which are characterized by seasonality. To test for the normality of electricity prices returns, we plot in Figure 3 the sample data of log returns against the standard normal distribution.

The quantiles of the log return distribution are plotted on the Y-axis and the quantiles of the standard normal distribution are plotted on the X-axis. Figure 3, shows that the distribution of



**Figure 2:** IPEX price - Autocorrelogram



**Figure 3:** IPEX Price - Testing for normality

log-returns fits well the normal distribution<sup>7</sup>. Finally, we run the Dickey Fuller unit root test to support the assumption that  $P_t$  is a GBM. The Dicky-Fuller critical F – value at the 5% level (for number of observations lower than 80) – is  $-2.706$ , so the null hypothesis of GBM cannot be rejected (See Appendix A).

Having established that the increments of  $\ln P_t$  exhibit GBM, we proceeded by estimating the relevant trend and uncertainty parameters  $\alpha_P$  and  $\sigma_P$ . For the the volatility we calculated  $\sigma_P = \sqrt{\sum_{i=1}^n \frac{(r_i - \hat{m})^2}{n}}$ , where  $\hat{m}$  is the sample mean of  $r_t$ . The monthly volatility is equal to 10,09% that corresponds to 34,95% in annual terms<sup>8</sup>. This value is consistent with the estimates in Escribano et al. (2011) and Crespo et al. (2012). To estimate the drift  $\alpha_P$ , we exploit the equation of log-returns to set a linear regression as follow:

$$r_t = \beta t + \varepsilon_t$$

where:  $\beta = \alpha_P - \frac{\sigma_P^2}{2}$  and  $\varepsilon_t = \sigma_P(B_{t+1} - B_t)$ . By running OLS we obtain a monthly drift equal to 0,509%. This corresponds to a growth rate of 6,11% in annual terms, which is quite above the value for Italy by Acanfora and Alcor (2012).

As usual for many commodities the electricity price is known to have a mean reverting behavior (Escribano et al. 2011). When a shift in demand increases the price, there is an economic incentive for more expensive generators to start producing, which, in turn, reverts the dynamics of prices. However, although a significant autocorrelation at the 12<sup>th</sup> lag can be an indication of

**Table 1:** OLS regression

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. reg RENDIMENTO mese
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Source	SS	df	MS	Number of obs = 92	
Model	.00096849	1	.00096849	F( 1, 90) =	0.08
Residual	1.02747232	90	.011416359	Prob > F =	0.7715
Total	1.02844081	91	.011301547	R-squared =	0.0009
				Adj R-squared =	-0.0102
				Root MSE =	.10685

RENDIMENTO	Coef.	Std. Err.	t	P> t	[95% Conf. Interval]	
mese	-.0001222	.0004195	-0.29	0.772	-.0009555	.0007112
_cons	.011226	.0228273	0.49	0.624	-.0341244	.0565764

this effect, the time series of the PUN is too short to exploit such a behavior. Therefore, instead of estimating a mean-reverting process, we decided to lower the GBM trend which tends to be too high. We do this by correcting  $\alpha_P$  by a measure of the speed the process takes to converge to the mean if it had been of mean-reverting type. For example in a Ornstein-Uhlenbeck process the conditional distribution of  $P_t$  at time  $t$  is normal with mean  $E(P_t) = P_0 e^{-\eta t} + (1 - e^{-\eta t})\bar{P}$ , where  $\bar{P}$  is the “long run mean” to which the process tends to revert and  $\eta$  is the speed of reversion. By using the IPEX data we estimate  $\eta = 0.0252$  (in annual term)<sup>9</sup>, then the adjusted drift  $\alpha_P$  becomes 0.0359 which is in line with Acanfora and Alcor (2012) estimates.

### 3.1 IPEX price and what the end user pays

The price that results from daily exchanges on the electricity market is only a fraction of the whole electricity price paid by end-users, both industrial users and domestic ones. The price paid by consumers includes other variables that should be considered. In the specific we analyse the components of the final prices used by the Italian Authority for Electricity and Gas (AEEG, Autorità garante per l’Energia Elettrica ed il Gas), and how these components can be incorporated in the Grid Parity model.

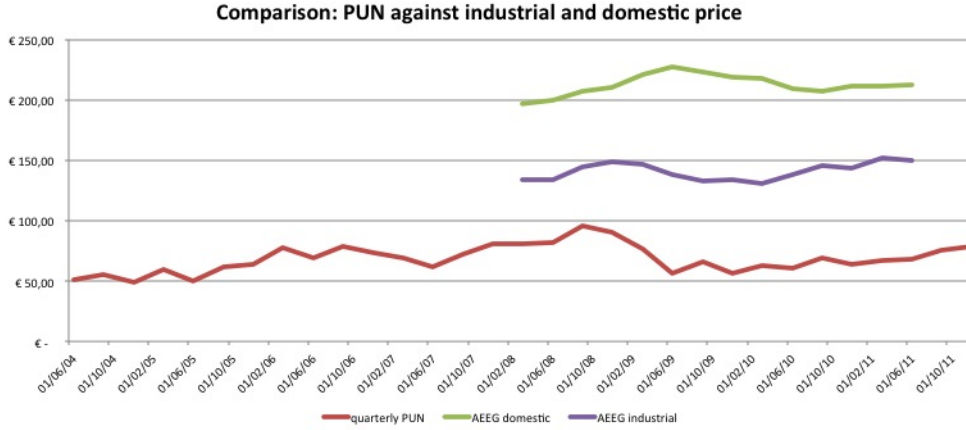
Figure 4 compares the IPEX (red line) with two different quarterly time series about domestic and industrial electricity prices. The domestic price (green line) and the industrial price (violet line), are the average prices calculated as the total amount paid by the end user weighted for the total energy consumption.

The most important factor of final electricity price is the PE (Price of Energy), this represents on average 50% of the final price. The PE is slightly different from the PUN. While the PUN is a market price, obtained from the arithmetical mean of hourly or daily prices, the PE is a weighted average of hourly prices and traded volumes. The PD (Dispatching Price) is the second major component of the final price, it represents the cost of dispatching energy into the grid and presents little changes over time. Then we must add costs for equalization and commercialization of energy, taxes, general system charges and network costs.

The key issue is to understand if we can use the dynamic of the PUN, previously described as a GBM, to identify the movements of the real price paid by end users, which can be identified with the average price published by the AEEG<sup>10</sup>. The answer has to be found in the nature of the different components of the end-user price. In fact, while the PED = PE + PD (Price of Energy + Dispatching Price), is strictly linked to the PUN (see GME (2011)), it is impossible to find a dynamic for the other components. They are strictly exogenous and depend mainly on political choices.

So, for matter of tractability, we take the PUN as a good proxy for the dynamics of PED





**Figure 4:** PUN comparison - data from <http://www.autorita.energia.it>

while, as starting point  $P_0$ , we use the “Residential User” and “Utility” prices taken from the AEEG publications ([www.autorita.energia.it](http://www.autorita.energia.it)). Those prices exclude taxes and are computed as an average of the 2011 end-users price. In the following Table we sum up the value of the drift and diffusion terms of price dynamics. The drift terms are presented for the GBM and for the Adj-GBM case.

**Table 2:** Drift and diffusion terms of electricity prices dynamic

	GBM		ADJ. GBM		$P_{2011}$
	$\alpha$	$\sigma$	$\alpha$	$\sigma$	
<b>RESIDENTIAL</b>	6,11%	34,95%	3,59%	34,95%	0,18
<b>UTILITIES</b>	6,11%	34,95%	3,59%	34,95%	0,13

## 4 PV Electricity Generation Costs

To analyse the dynamics of the generation costs of a PV plant we use the LCOE (Levelised Cost of Electricity). The LCOE is an easy tool used to compare the unit costs of different power generation technologies along their economic lifetime. It can be used even if different scales of operation, investment or operating time periods exist. It captures capital costs, on-going system-related costs and fuel costs – along with the amount of electricity produced – and converts them into a common metric (See Appendix B).

The LCOE is an important tool for both policy makers and private investors to understand the main cost drivers of electricity systems. However a full analysis of an investment project would complement the LCOE with a more comprehensive risk analysis, where multiple risks are taken into account. In this respect, as it will be explained in the following paragraphs, our grid parity analysis will be made according to two different perspectives. We consider the investment decision by a public institution (“Public Analysis” case), and compare it to the investment choice by a private investor (“Private Investor Analysis” case).

The values of LCOE are taken from two different sources. A first set of data is taken from Marchesi et al. (2010). This study has been commissioned to the Politecnico di Milano by AEEG. A second set of data is taken by a comprehensive study on the unit cost of different power generation technologies prepared by Salvadores and Keppler (2010a) for the IEA.

The LCOE of a PV system is highly sensitive to variations in the load factor and in the construction costs<sup>11</sup>. The load factor, or capacity factor, is particularly important since it defines the amount of electricity produced per unit of generating capacity. It has a high impact on the unit cost because the percentage of fixed investment costs is really high for PV power plants. Variation of the load factor is markedly skewed to the right, revealing that plants are particularly sensitive to decreases in the load factor.

Construction costs account for nearly 95% of the whole cost of a PV plant. One of the key factors which drives construction costs is the scale of the installation: small residential PV plants present higher investment costs per kw/h compared to bigger utility scale plants. The discount rate is the third variable in order of importance. This is due to the short construction times of PV power generation technologies. The incidence of the economic lifetime variations has to be considered for the asymmetric distribution of its effects. While early retirement significantly increases the LCOE, lifetime extension have little or no impact. Clearly, early retirement have a strong impact on the ability to repay the initial capital investment. For this purpose, the lifetime considered in the work by Marchesi et al. (2010) is prudentially fixed around 20 years, while most studies use 25 or even 30 years. Finally, the absence of fuel costs is one of the major advantages of renewable energy sources, which are not influenced by the volatility of fuel prices.

#### 4.1 The LCOE

The set of data from the work by Politecnico di Milano are used to run the “Public Analysis” case (Table 3). The low discount rate (i.e. 4%), used in the computation, well reflects the point of view of a public investor. Furthermore, this work takes into account the important effect of plant size: the LCOE is calculated for both 3kw (RESIDENTIAL) and 1Mw (UTILITY) installation.<sup>12</sup> The overall PV system cost highly depends on the size of the system and on whether the system is ground-or-roof-mounted-residential plants.

**Table 3:** Data from Marchesi et al. (2010)

Plant size	Discount rate	Economic lifetime	Capacity factor	Capital Expenditures <sup>°</sup>	O&M*	Assurance Costs*	LCOE <sub>2010</sub> **
<b>3 Kw</b>	4%	20	14%	5.996	108	51	<b>0,531</b>
<b>1000 Kw</b>	4%	20	14%	3.425	39	9	<b>0,257</b>

(°) expressed in €/Kw

(\*) expressed in €/Kw year

(\*\*) expressed in €/Kwh

The data from Salvadores and Keppler (2010a) are used to run the “Private Investor Analysis” case (Table 4). These authors use two different discount factors: 5% and 10%, that best capture a risk premium . In the remain of the paper, the first hypothesis will be called IEA5 and the second IEA10. As we said before, the 10% discount rate is considered to internalize the technology and market risks so that a higher discount rate results in a higher LCOE<sup>13</sup>.

#### 4.2 Learning Curves

To predict the dynamics of LCOE we follow the learning curve approach. In the specific, the learning curve approach is an empirical-based methodology, designed to describe the law of cost reduction for a specific industry, based on the assumption that at each doubling of cumulated output costs decrease by a stable percentage<sup>14</sup>.

There are several reasons that contributes to the ample diffusion of learning curves: i) the readiness of the empirical time series required for its computation – cumulative capacity and

**Table 4:** Data from Salvadores and Keppler (2010a)

Discount rate	Economic lifetime	Capacity factor	Capital Expenditures <sup>°</sup>	O&M*	LCOE <sub>2010</sub> **
5%	25	16%	6.592	54	0,31
10%	25	16%	6.592	54	0,46

(°) expressed in €/Kw

(\*) expressed in €/Kw year

(\*\*) expressed in €/Kwh

costs – facilitates the capability to test the model; ii) they are capable to express with a single parameter the complex process of innovation; iii) they are consistent with the theory that firms learn on past experience and iv) the learning rate is not usually linked to a time variable, but to variations in cumulative production and thus seems to be more suitable for forecasts on future costs. However, the experience curve approach presents also many cons. The decrease in costs is described by a unique parameter and so results are highly sensitive to the learning rate used, which is not able to describe discontinuities in costs. The experience curve does not consider the knowledge acquired from other sources like R&D expenditures and ignores changes in the quality of the output. Moreover, industry structure affects the learning rate and so, for an industry that is becoming more and more competitive like the photovoltaic one, the experience curve could over-estimate the rate of technical progress<sup>15</sup>.

While there is an ample literature on the advantage and use of learning curves, few sources have done an accurate analysis on how to use the learning curve approach for the PV industry Acanfora and Alcor (2011), Nemet (2006).

Following this approach, in Appendix C, we express the PV unit cost dynamics on both the average growth rate of the PV industry,  $GR$ , and the learning coefficient  $LN$ . The latter is calculated from the slope of the learning curve, called progress ratio ( $PR$ ), that express the percentage of costs decrease at each doubling of cumulated capacity. That is:

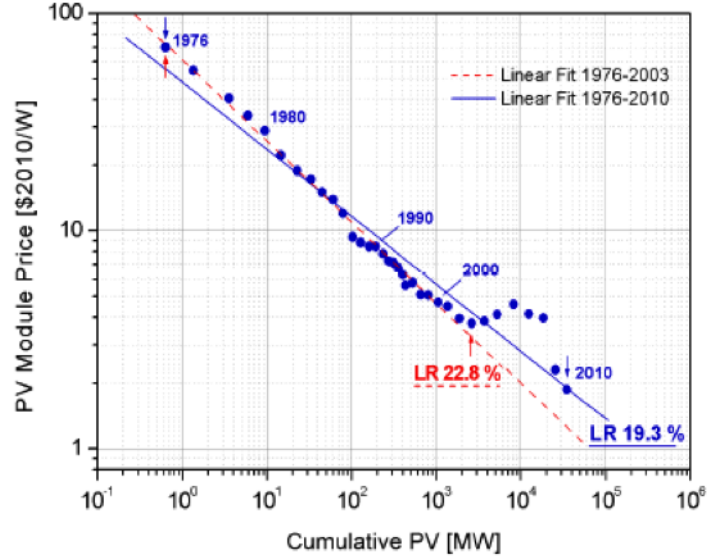
$$LCOE_t = LCOE_0 e^{\alpha_C t} \quad (3)$$

where  $\alpha_C = LN \cdot GR$  and  $LN = \frac{\ln PR}{\ln 2}$ .

To properly use (3) we need to calibrate  $\alpha_C$ . Then we test if  $LCOE_{2030}$  (the expected levelised cost for PV in 2030) is in line with the projected values of IEA, where  $LCOE_0$  refers to the level of the Italian Levelised Cost of Electricity in 2010.

As the industry has grown PV module prices have shown an important decline (Figure 5)<sup>16</sup>. In particular, from the first statistical data dating back to 1976 to the beginning of the 2000s, module prices decrease shows a learning rate,  $LR = (1 - PR)$ , of about 22%. An excursion from this historical rate occurred due to supply bottlenecks and market dynamics – the so-called polysilicon-shortage – from 2003 to the end of 2008. Since then the learning curve returned toward its historic level, reaching a  $LR$  of about 19%. Nowadays, the IEA and EPIA expect further costs reduction due to increased production capacities, improved supply chains and economies of scale. Following Crespo et al. (2012), we use an average  $LR$  of 20%, which implies a  $PR$  of 80%<sup>17</sup>.

Let's now consider the  $GR$ . Although the short-term expectations about the Italian PV market could be very volatile, a long-term definition of the expected dynamic of the market could be more reliable.<sup>18</sup> In particular, we use two different  $GR$ s. In a first CONSERVATIVE scenario, we set  $GR = 10\%$ . This is based on the forecasts of the 2012 Solar Energy Report for the Italian PV industry growth till 2020. In a second, more “optimistic”, scenario we set



**Figure 5:** Learning curve dynamic – Data from Breyer and Gerlach (2010)

$GR = 18\%$ , considering the possibility of a new photovoltaic development in Italy boosted by the adoption of Smart Grids (SMART GRIDS scenario). This second scenario is in line with the EPIA expectations till 2020 (EPIA, 2012)<sup>19</sup>. Finally, by using the  $GR$  of the Italian PV industry in 2011, we update our starting point from 2010 to 2011.

Plugging the values for  $LN$  and  $GR$  in (3), in Table 5 we show our projections for the four cases considered. The 2020 LCOE projections made by the IEA are between 0,09 €/Kwh and 0,19 €/Kwh for the UTILITY sector and 0,12 €/Kwh and 0,23 €/Kwh for the RESIDENTIAL sector. Furthermore, both the SMART GRIDS scenario and the CONSERVATIVE one are in line with the IEA expectations<sup>20</sup>, except for the RESIDENTIAL value, which is slightly over the range in the CONSERVATIVE case. Finally LCOE expectations for 2030 are within 0,07 €/Kwh and 0,15 €/Kwh that is the range proposed by the IEA.

**Table 5:** LCOE projections

CONSERVATIVE SCENARIO - GR=10%		SMART GRIDS SCENARIO - GR=20%	
OUTPUTS	LCOE <sub>2030</sub>	OUTPUTS	LCOE <sub>2030</sub>
RESIDENTIAL	0,17	RESIDENTIAL	0,10
UTILITY	0,08	UTILITY	0,05
IEA5	0,10	IEA5	0,06
IEA10	0,15	IEA10	0,09

Finally, Bosetti et al. (2012), by interviewing some of the major European PV market experts, calculate a range of values for LCOE in 2030. In this respect, most experts project that  $LCOE_{2030}$  will lay between 0,05 €/Kwh and 0,11 €/Kwh. These estimates, that are more optimistic than the ones by IEA, give further support to our learning model.

We conclude this section adding a volatility term to equation (3) to account for possible deviations of the learning rate from its historical trend. Deviations from the historical learning rate can be explained by variations in PV module costs, mainly due to silicon supply and demand conditions. However, since an estimate of the volatility of PV module prices is very difficult to compute we will use, as a proxy, the stock prices volatility of the four biggest global producers of PV modules (See Table 6).

**Table 6:** Weighted volatilities of the four major PV module producers, data from www.yahoofinance.com

<b>LCOE VOLATILITY</b>				
	<b>VOL</b>	<b>MARKET SHARE</b>	<b>AJUSTED MARKET SHARE</b>	<b>VOLATILITY</b>
SUNTECH	51%	6%	29%	14%
FIRST	69%	6%	29%	20%
YINGLI	39%	5%	24%	9%
TRINA	58%	4%	19%	11%
		21%	100%	54%

Following the approach used for the electricity price, we have estimated the stock price volatility for Yingli Solar, First Solar, Suntech and Trina Solar. For the volatility of LCOE we calculate the average volatility of the four companies, weighted for their respective market shares. Table 7 sums up the data involved in the analysis.

**Table 7:** Continuous time model inputs

<b>LCOE CONTINUOUS TIME MODEL - INPUTS</b>	<b>DRIFT TERM</b>	<b>VOLATILITY</b>
<b>CONSERVATIVE SCENARIO</b>	-3,22%	54%
<b>SMART GRIDS SCENARIO</b>	-6,44%	54%

This yields<sup>21</sup>:

$$\frac{dLCOE_t}{LCOE_t} = \alpha_C dt + \sigma_C dz, \quad \text{where } \alpha_C = GR_C LN \quad (4)$$

where  $\alpha_C = LN \cdot GR$  and  $\sigma_C$  expresses the module price volatility.

## 5 Grid Parity Dynamics

Grid Parity models express a break-even point for an investment in PV plants. Grid Parity is usually defined as the time  $t^*$  when PV installations become cost neutral and so the electricity price equals the levelised cost of PV generation (i.e. LCOE). Our Grid Parity analysis overcomes this definition. Our model is based on a wider view of Grid Parity timing, where the optimal  $t^*$  internalizes the value of the option to have more information about future evolution of both the electricity price and the unit cost of PV generation. In the next section we first calibrate a standard Grid Parity model and then we provide our Real Option Grid Parity model. For both the models we present two different sets of results. First, we analyse the Grid Parity from the point of view of a public investor (“Public”), focusing on residential and utility plants (RESIDENTIAL, UTILITY). Second, we consider the private investor perspective (“Private”), where the LCOE is calculated using two different discount rates (IEA5, IEA10). Further, we calculate the Grid Parity time  $t^*$  considering a learning curve with a  $GR = 10\%$  (CONSERVATIVE) and with  $GR = 20\%$  (SMART GRIDS) and for both the GBM case and the Adj-GBM case.

### 5.1 The Standard Grid Parity Model

The aim of this section is to find the time  $t^*$  where the expected value of electricity prices equals the expected cost of PV plants, expressed by the LCOE<sup>22</sup>.

$$E_0(P_{t^*}) = E_0(LCOE_{t^*}) \quad (5)$$

where  $E_0(\cdot)$  is the expectation taken at time  $t = 0$  with respect to (1) and (4) respectively. By substituting and solving for  $t^*$ , we get:

$$t^* = \max \left[ \frac{\ln \left( \frac{LCOE_0}{P_0} \right)}{\alpha_P - \alpha_C}, 0 \right] \quad (6)$$

Plugging our data into (6) we obtain:

### Public Perspective Analysis

Grid Parity will be reached in 2013-2014 by UTILITY, while the RESIDENTIAL sector will reach the Grid Parity between 2016 and 2020.

**Table 8:** Standard Grid Parity Model - Public Analysis results

GEOMETRIC BROWNIAN MOTION			ADJ GBM		
	CONSERVATIVE	SMART GRIDS		CONSERVATIVE	SMART GRIDS
RESIDENTIAL	ott-17	apr-16	RESIDENTIAL	dic-19	mag-17
UTILITY	giu-13	gen-13	UTILITY	gen-14	mag-13

In particular, the results for UTILITY are quite homogeneous. Given that electricity prices are already very close to the utilities' LCOEs, a different growth rate has not so much influence on Grid Parity timing. This result is coherent with the phase out of the Italian FIT program, where the end of the incentive schemes is more gradual for residential customers. On the other side, the RESIDENTIAL sector is strongly influenced by forecasts on future developments of the PV industry. Since the initial gap between prices and costs is higher, a higher growth rate has an important effect on Grid Parity timing. Specifically, when we take into account a lower drift for electricity prices (i.e. in Adj-GBM case), the gap between CONSERVATIVE and SMART GRIDS increases.

According to Politecnico di Milano (2012) and Acanfora and Alcor (2011), our model concludes that residential customers should need some form of public intervention in the following years to reach Grid Parity: only through a sustained growth rate they will afford a cost-competitive investment. For this reason, the introduction of smart grids might have an important role on future expansions of the PV industry.

### Private Investor Analysis

Table 9 shows that the results of the IEA5 scenario are in line with the EPIA forecasts, which consider the period between 2013 and 2015 for the ground-mounted PV systems to be cost-competitive. However, using the Adj-GBM, which uses a (lower) more reasonable growth rate in the price of electricity, we obtain a substantial delay.

**Table 9:** Standard Grid Parity Model - Private Analysis results

GEOMETRIC BROWNIAN MOTION			ADJ GBM		
	CONSERVATIVE	SMART GRIDS		CONSERVATIVE	SMART GRIDS
IEA5	giu-15	lug-14	IEA5	ott-16	mar-15
IEA10	set-19	set-17	IEA10	ago-22	feb-19

A delay is also obtained when LCOE considers a higher discount rate (IEA10). Note, however, that in the case of Adj-GBM a higher growth rate could anticipate the Grid Parity by about three years in the CONSERVATIVE case<sup>23</sup>.

## 5.2 A Stochastic Model

The standard Grid Parity model presents two main shortcomings. First, it does not consider that an investment in a photovoltaic power plant is irreversible (construction costs account for 95% of the whole cost of a PV plant). Second, it does not take into account the opportunity of waiting to have more information about prices and market conditions before making the investment decision. In other words, the standard model ignores to add among the costs the opportunity cost of investing as soon as  $P$  equals  $LCOE$ .

To overcome these weakness, in this section, we use the Real Option approach to evaluate the Grid Parity timing. Indicating with  $F(P, LCOE)$ , the value of the opportunity to invest in a PV project, this is given by:

$$F(P, LCOE) = E_0 [e^{-\mu t^{**}} (P_{t^{**}} - LCOE_{t^{**}})] \quad (7)$$

where  $\mu > 0$  is the risk-adjusted discount rate,  $t^{**}$  is the (stochastic) Grid Parity time defined as  $t^{**} = \inf\{t \geq 0 : F(P_{t^{**}}, LCOE_{t^{**}}) = P_{t^{**}} - LCOE_{t^{**}}\}$ , and  $E_0(\cdot)$  is the expectation operator taken with respect to (1) and (4)<sup>24</sup>. It is evident from (7) that the condition that identifies the Grid Parity is  $P_{t^{**}} = LCOE_{t^{**}} + F(P_{t^{**}}, LCOE_{t^{**}})$ , i.e. the price has to be equal the full cost (LCOE + opportunity costs) of making the investment. Standard arguments lead to a solution for (7) taking the following functional form (see Appendix D):

$$F(P, LCOE) = AP^\beta LCOE^{1-\beta} \quad (8)$$

where  $A$  is a positive constant and  $\beta$  is equal to:

$$\beta = \frac{\frac{1}{2}(\sigma_P^2 + \sigma_C^2) - (\alpha_P - \alpha_C) + \sqrt{\left(\frac{1}{2}(\sigma_P^2 + \sigma_C^2) - (\alpha_P - \alpha_C)\right)^2 + 2(\sigma_P^2 + \sigma_C^2)(\alpha_C - \mu)}}{\tilde{\sigma}^2} > 1,$$

while the optimal threshold is given by:

$$\frac{P^{**}}{LCOE^{**}} = \frac{\beta_1}{\beta_1 - 1}. \quad (9)$$

For the Grid Parity  $t^{**}$  we should calculate the time that the ratio  $\frac{P}{LCOE}$  takes to reach the investment trigger (9). In this regard, since  $\frac{P}{LCOE}$  is stochastic  $t^{**}$  is stochastic as well, therefore we need to refer to the probability distribution of  $t^{**}$ . In particular, we calculate the average time (See Appendix D):

$$E(t^{**}) = m^{-1} \left[ \ln \left( \frac{\beta_1}{\beta_1 - 1} \right) - \ln \left( \frac{P_0}{LCOE_0} \right) \right] \quad (10)$$

and the 95% confidence interval  $E(t^{**}) \pm 1,96\sqrt{Var(t^{**})}$ , where  $m = \sigma_C^2 + \alpha_P - \alpha_C - \frac{1}{2}(\sigma_P^2 + \sigma_C^2)$  and  $Var(t^{**})$  is the variance of the distribution of  $t^{**}$ .

To complete the analysis we need to compute the risk-adjusted cost of capital  $\mu$ . We do this by using the Capital Asset Pricing Model formula  $\mu = r + \mathbf{B}(MRP)$ , where  $MRP$  is the market risk premium,  $\mathbf{B}$  measures the systematic risk and  $r$  is the risk free interest rate. Following Fernandez et al. (2011), we use 5.50% for the Italian market risk premium. For the risk-free interest rate we take the average of the last 10 years interest rates on the Italian BTP (maturity 15 year) as published by the Italian ‘‘Dipartimento del Tesoro’’, i.e.  $r = 4.70\%$ . Finally, for  $\mathbf{B}$  we calculate the average unlevered betas of three representative European companies that produce electrical energy from renewable sources (see Table 10). Putting all this information together we obtain  $\mu = 10.07\%$

**Table 10:** Beta estimation - Data from www.yahoofinance.com

	<b>COUNTRY</b>	<b>BETA LEVERED</b>	<b>DEBT/EQUITY*</b>	<b>BETA DEBT</b>	<b>BETA UNLEVERED</b>
<b>THEOLIA</b>	FRANCE	1,59	1,16	0,71	1,12
<b>TERNA ENRGY</b>	GREECE	0,98	0,49	0,15	0,71
<b>GREEN TECH</b>	DENMARK	1,67	0,81	0,41	1,11
<b>AVERAGE BETA</b>					0,98

\*debt/equity has been taken from the annual reports of the single companies or, alternatively, from yahoo finance data

## Public Perspective Analysis

Table 11 shows the results for (10). Taking into account the opportunity cost of investing led, on average, to a ten years postponement of the equality between prices and full costs of the investment. In the specific, the optimal investment timing for RESIDENTIAL customers falls in between 2025 and 2027, while for UTILITY installations the best time to invest falls in between 2023 and 2025.

**Table 11:** Stochastic Grid Parity Model - Public Analysis results

<b>GEOMETRIC BROWNIAN MOTION</b>			<b>ADJ GBM</b>		
	<b>CONSERVATIVE</b>	<b>SMART GRIDS</b>		<b>CONSERVATIVE</b>	<b>SMART GRIDS</b>
<b>RESIDENTIAL</b>	giu-27	giu-25	<b>RESIDENTIAL</b>	feb-27	feb-27
<b>UTILITIES</b>	mar-25	lug-23	<b>UTILITIES</b>	giu-24	giu-24

Yet, moving from the CONSERVATIVE scenario to the SMART GRID one the uncertainty surrounding  $P$  and  $LCOE$  has the same impact on UTILITY and RESIDENTIAL installations. The effect of the growth rate is smoothed with respect to the standard Grid Parity model and the difference between the GBM and Adj-GBM is virtually zero.

## Private Investor Analysis

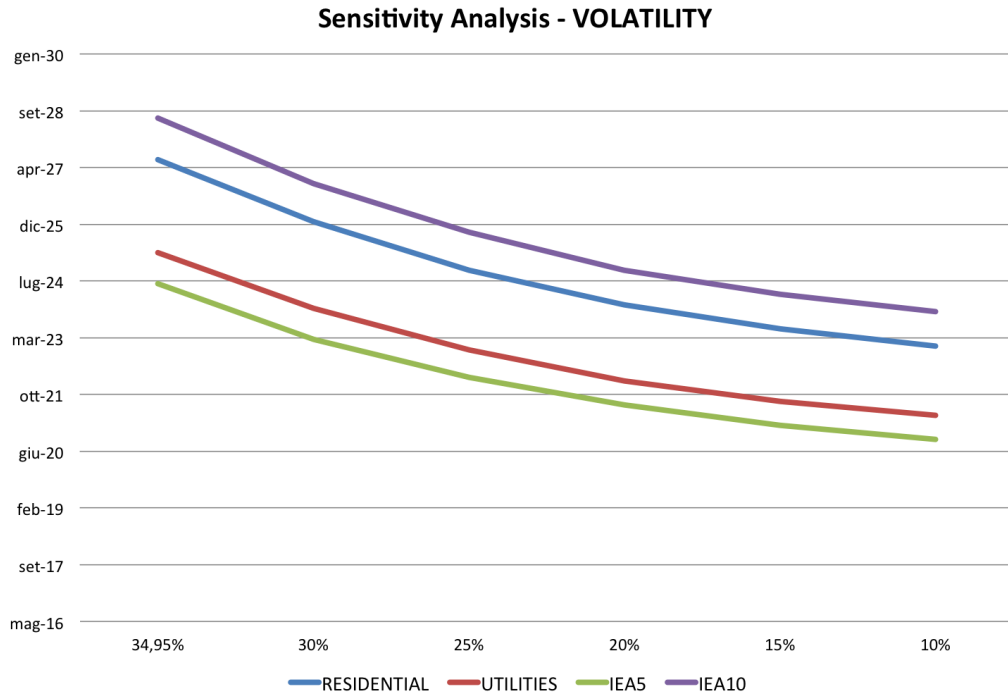
Even for a private investor the optimal investment timing will be postponed with respect to the one calculated with the standard model. In particular the average time ranges between 2022 and 2024 in the lower 5% discount rate scenario and it is postponed till 2028 when LCOE is calculated with a 10% discount rate. In both cases, a 10% increase in the learning rate anticipates by two years the investment decision (see Table 12).

**Table 12:** Stochastic Grid Parity Model - Private Analysis results

<b>GEOMETRIC BROWNIAN MOTION</b>			<b>ADJ GBM</b>		
	<b>CONSERVATIVE</b>	<b>SMART GRIDS</b>		<b>CONSERVATIVE</b>	<b>SMART GRIDS</b>
<b>IEA5</b>	giu-24	nov-22	<b>IEA5</b>	set-25	set-25
<b>IEA10</b>	giu-28	apr-26	<b>IEA10</b>	apr-28	apr-28

The above results show how the Grid Parity is mainly driven by uncertainties over prices and costs. To highlight this effect in Figure 6 we conduct some comparative statics analysis with respect to  $Var(t^{**})$ . According to the Real Options approach, the average time reduces as the uncertainty decreases up to converge to the deterministic case represented by the Standard

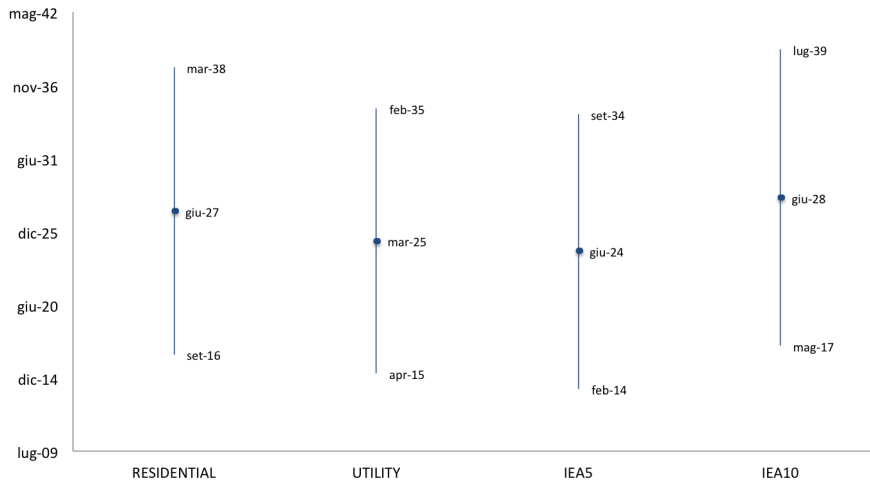




**Figure 6:** Sensitivity analysis with respect to price volatility.

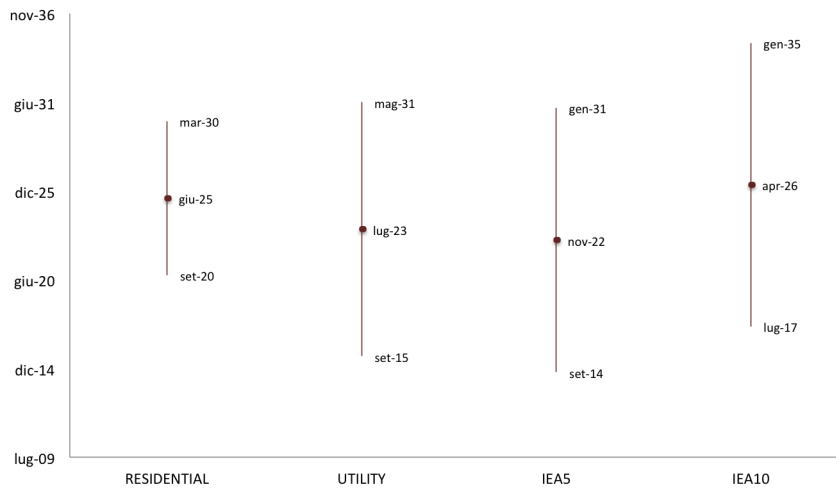
Model. Finally, we conclude showing in Figure 7, for all cases, the respective 95% confidence intervals. Comparing the confidence intervals of the Conservative scenario and the Smart Grids one, we can see that, when the assumed growth rate of the PV industry is higher, confidence intervals are lower. Our expectations are more precise.

### CONFIDENCE INTERVALS - CONSERVATIVE SCENARIO



(a) Confidence Intervals for the Conservative Scenario - GBM framework.

### CONFIDENCE INTERVALS - SMART GRIDS SCENARIO



(b) Confidence Intervals for the Smart Grids Scenario - GBM framework.

## 6 Final Remarks

Calibration of the standard Grid Parity model confirms literature's findings. Due to relatively high electricity prices and good solar irradiation, the PV Grid Parity is going to be reached soon in Italy. In the case of a private investor, for example, the Grid Parity can be reached in 2015 while considering a public perspective, the Grid Parity can be reached by 2014.

However, the break-even analysis behind the standard model does not take into account two important aspects of a decision to invest in a PV system: the sunkness of the investment cost and the uncertainty related to both the electricity prices and the energy generation costs.

In this paper we take into account both of these aspects by calibrating a Real Option model of the Grid Parity. The high volatility of energy prices and the uncertain future path of module costs give rise to a high value to wait before investing in a PV plant. Our stochastic model changes substantially the investment decision, well describing the current market situation. In the case of the private investor, for example, Grid Parity can be postponed until 2025, while considering a public perspective, the optimal time to invest in a PV system can be postponed up to ten years.

## A The Dickey Fuller test

The simplest way to test for a unit root is by running the following regression:

$$p_t - p_{t-1} = \alpha + \theta p_{t-1} + e_t. \quad (\text{A.1})$$

where  $p_t$  is the natural logarithm of electricity prices  $P_t$  and  $E(e_t | p_{t-1}, p_{t-2}, \dots, p_0) = 0$  in accordance with the use of a Wiener process. The process has a unit root if and only if  $\theta = 0$ . Yet, if  $\alpha = 0$  and  $\theta = 0$ ,  $p_t$  follows a random walk without drift, while if  $\alpha \neq 0$  and  $\theta = 0$ ,  $p_t$  is a random walk with drift<sup>25</sup>. The null hypothesis is that  $p_t$  has a unit root  $H_0 : \theta = 0$  against  $H_1 : \theta < 0$ . We dispose of 8 years monthly data on electricity prices, from April 2004 to December 2011, taken from the statistical publications of the GME (Gestore Mercati Energetici). As shown in Table 13 given a critical value of  $-2,706$  for the test, we fail to reject the null hypothesis that the process has a unit root at the 5% significance level.

Table 13

```
. dfuller LOGPRICE, lags(12)
```

Augmented Dickey-Fuller test for unit root                      Number of obs =                      80

Test Statistic	Interpolated Dickey-Fuller		
	1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-2.706	-2.906	-2.588

Mackinnon approximate p-value for Z(t) = 0.0729

We obtain the same results running the regression (A.2) where we include 12 additional lags to control for autocorrelation:

$$\Delta p_t = \alpha + \theta p_{t-1} + \sum_{i=1}^{12} \gamma_i \Delta p_{t-i} + e_t. \quad (\text{A.2})$$

where *rendregress* is the log returns of electricity prices, *ptmeno1* is  $p_{t-1}$  and the other values presents the  $\gamma_i$  coefficients of  $\Delta p_{t-1}$ . The coefficient of  $p_{t-1}$  is statistically different from 0, i.e.  $\theta = -0,223$  with a *t - statistics* of  $-2,71$ . Note that only the  $\gamma_i$  at the 12<sup>th</sup> lag is statistically significant.

## B Cost components for photovoltaic energy systems

We define the LCOE as the cost that, if assigned to every unit of energy produced by the system over the lifetime period, will equal the total lifetime cost, when discounted back to the base year. That is:

$$\sum_{t=1}^N \frac{\text{Electricity}_t \cdot \text{LCOE}}{(1+r)^t} = \frac{\sum_{t=1}^N (\text{Capex}_t + \text{Opex}_t + \text{Assurance}_t)}{(1+r)^t}$$

or

$$\text{LCOE} = \frac{\sum_{t=1}^N (\text{Capex}_t + \text{O\&M} \text{pex}_t + \text{Assurance}_t) \cdot (1+r)^{-t}}{\sum_{t=1}^N \text{Electricity}_t \cdot (1+r)^{-t}} \quad (\text{B.1})$$

Table 14:

```
. reg rendregress ptmeno1 deltapt1 deltapt2 deltapt3 deltapt4 deltapt5 deltapt6 deltapt7 deltapt8 deltapt9 del
> tapt10 deltapt11 deltapt12
```

Source	SS	df	MS			
Model	.28375555	13	.02182735	Number of obs =	80	
Residual	.48028634	66	.007277066	F( 13, 66) =	3.00	
Total	.764041889	79	.009671416	Prob > F =	0.0017	
				R-squared =	0.3714	
				Adj R-squared =	0.2476	
				Root MSE =	.08531	

rendregress	Coef.	Std. Err.	t	P> t	[95% Conf. Interval]	
ptmeno1	-.2228634	.0823482	-2.71	0.009	-.3872768	-.0584499
deltapt1	.0155378	.1240744	0.13	0.901	-.2321847	.2632603
deltapt2	.0890547	.1208675	0.74	0.464	-.152265	.3303744
deltapt3	-.0701103	.1191143	-0.59	0.558	-.3079297	.1677091
deltapt4	.0862973	.1134832	0.76	0.450	-.1402792	.3128738
deltapt5	.1762118	.1132094	1.56	0.124	-.049818	.4022417
deltapt6	.151459	.1149865	1.32	0.192	-.0781191	.381037
deltapt7	.0744898	.1162276	0.64	0.524	-.1575662	.3065458
deltapt8	.0348012	.1143822	0.30	0.762	-.1935703	.2631727
deltapt9	-.0588186	.1122933	-0.52	0.602	-.2830194	.1653822
deltapt10	.0476605	.1098222	0.43	0.666	-.1716067	.2669277
deltapt11	-.0580206	.1004652	-0.58	0.566	-.2586058	.1425645
deltapt12	.2885621	.0977004	2.95	0.004	.0934969	.4836273
_cons	.9485971	.3481746	2.72	0.008	.2534441	1.64375

where  $r$  is the discount factor (assumed to be constant),  $N$  is the economic life of the system,  $Electricity_t$  is the electricity produced by the plant in year  $t$ ,  $Capex_t$  are annualized capital expenditures<sup>26</sup>,  $O\&Mpx_t$  are the operating and maintenance costs for each year and  $Assurance_t$  is the annual assurance cost. The capital cost,  $Capex$ , can be divided in two major components: the price of the PV module and the Balance Of System costs (BOS). The price of the PV module clearly depend on the price of silicon, while the BOS costs are linked to the price of the inverter, the costs for the structural installation and other wiring and installation costs. The price of the module is typically between a third and a half of the total capital cost and has been one of the driving forces of PV costs reduction.  $O\&Mpx$  costs have a low incidence on LCOE, photovoltaic is well known to have low annual operational costs and low needs for maintenance during its life<sup>27</sup>. Finally, it is worth mentioning the important cost of assurance needed to cover the risk that the modules are stolen.

Further, we have to consider two important parameters that influence the output ( $Electricity$ ): the level of solar irradiation and the efficiency of solar cells. They will be both synthetized by the net Capacity Factor. The net Capacity Factor is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time (www.nrc.gov). Both solar irradiation and the efficiency of solar cells contribute to its variations and so the latitude of the installation site is crucial for the cost of PV systems.

Finally, given that LCOE is based on a DCF analysis, where the costs are computed discounting annual flows to a common basis, we have to take into consideration the time value of money. This value is not necessarily the same for all investors and it is influenced by a variety of factors, such as the investor rate of return, risk premium, planning horizon and others.

## C A continuous-time learning model

The base formulation of a learning curve (see Nemet 2006), takes the cost of the  $N$ -th unit produced as a proxy of the cumulated experience, while the dependent variable is the cumulated production, which provides a measure of learning and technological improvement. That is:

$$C_N = C_0 N^{LN} \quad (\text{C.1})$$

where  $C_N$  is the cost of the  $N$ -th unit produced,  $C_0$  is the cost of the first unit,  $N$  is the cumulated production and  $LN$  is the learning curve coefficient. Assuming that costs decrease by a fixed amount every time quantity doubles, we are able to express the slope of the learning curve, called progress ratio ( $PR$ ), by the percentage of costs decrease at each doubling of cumulated capacity. That is,  $PR = 2^{LN}$  or,  $LN = \frac{\ln PR}{\ln 2}$ .

Let now define the annual capacity installations of the photovoltaic industry as follows:

$$W_s = W_{s-1}(1 + GR), \quad s \geq 1 \quad (\text{C.2})$$

where  $W_s$  is the capacity installed in year  $s$  and  $GR$  is the average growth rate of the PV industry, assumed to be constant. The cumulative capacity up to  $t > s$  can be calculated as:

$$W_t = W_0 \sum_{s=0}^t (1 + GR)^s.$$

Substituting this definition of cumulative capacity in equation (C.2), and considering  $LCOE$  as the unit cost, we can write the learning relationship as follow<sup>28</sup>.

$$LCOE_t = LCOE_0 \left( \sum_{s=0}^t (1 + GR)^s \right)^{LN} \quad (\text{C.3})$$

This discrete-time learning model is the same used by Breyer and Gerlach (2010), derived from Wright (1936) (the so-called Wright's cumulative model). Taking  $m$  as the detection frequency of the growth rate – usually expressed in annual terms – we can rewrite the previous expression as follows:

$$LCOE_t = LCOE_0 \left( \sum_{s=0}^t \left( 1 + \frac{GR}{m} \right)^{sm} \right)^{LN}. \quad (\text{C.4})$$

Letting  $m \rightarrow \infty$  equation (C.4) reduces to:

$$\begin{aligned} LCOE_t &= LCOE_0 \left( \int_0^t e^{GRs} ds \right)^{LN} \\ &= LCOE_0 e^{LN \ln \left( \frac{1}{GR} (e^{GRt} - 1) \right)}. \end{aligned} \quad (\text{C.5})$$

Now, from (C.5) it is easy to show that the rate of change is equal to:

$$\frac{dLCOE_t}{LCOE_t} = LN GR \frac{e^{GRt}}{e^{GRt} - 1} dt$$

which is driven by both the average growth rate of the PV industry  $GR$  and the learning curve coefficient  $LN$ . Since  $\frac{e^{GRt}}{e^{GRt} - 1} \rightarrow 1$  as  $t$  increases, for the sake of simplicity, we reduce the LCOE's rate of change as:

$$\frac{dLCOE_t}{LCOE_t} = \alpha_C dt, \quad \text{where } \alpha_C = LN GR \quad (\text{C.6})$$

## D Equations (9) and (10)

Writing  $C$  for  $LCOE$ , equation (7) becomes:

$$F(P, C) = E_0 [e^{-\mu t^{**}} (P_{t^{**}} - C_{t^{**}})].$$

The general solution for  $F(P, C)$  as well as the optimal Grid Parity threshold  $P_{t^{**}} - C_{t^{**}}$  can be obtained by verifying that the expected change of  $F(P, C)$  satisfies a second-order linear differential equation under some suitable boundary conditions at  $t^{**}$ . By applying a standard dynamic programming approach, the project's value,  $F(P, C)$ , solves the following Bellman equation:

$$\mu F(P, C) dt = E_0 [dF(P, C)]. \quad (\text{D.1})$$

Using Itô's Lemma, we can expand  $dF(P, C)$  and rearrange (D.1) as follows:

$$\frac{1}{2}(\sigma_P^2 P^2 F_{PP} + \sigma_C^2 C^2 F_{CC}) + P\alpha_P F_P + C\alpha_C F_C - \mu F = 0 \quad (\text{D.2})$$

where  $F_{PP}$ ,  $F_{CC}$ ,  $F_P$  and  $F_C$  are the first and second partial derivative with respect  $P$  and  $C$ . Since  $F(P, C)$  is homogeneous of degree 1 in  $(P, C)$  allows us to reduce it to one dimension. The optimal decision should therefore depend only on the ratio  $p \equiv \frac{P}{C}$ , i.e.:

$$F(P, C) = C f\left(\frac{P}{C}\right) = C f(p)$$

where  $f$  is now the function to be determined. Successive differentiation gives

$$\begin{aligned} F_P(P, C) &= f'(p), & F_C(P, C) &= f(p) - p f'(p) \\ F_{PP}(P, C) &= \frac{f''(p)}{C} & F_{PC}(P, C) &= -\frac{p f''(p)}{C}, & F_{CC}(P, C) &= \frac{p^2 f''(p)}{C}. \end{aligned}$$

Substituting these into (D.2) and grouping terms, we get:

$$\frac{1}{2}(\sigma_P^2 + \sigma_C^2) p^2 f''(p) + (\alpha_P - \alpha_C) p f'(p) + (\alpha_C - \mu) f(p) = 0. \quad (\text{D.3})$$

This is an ordinary differential equation for the unknown function  $f(p)$  of the scalar independent variable  $p$ . Its boundary conditions can be defined as follows:

$$f(p) = p - 1 \quad (\text{D.4})$$

$$f'(p) = 1, \quad f(p) - p f'(p) = -1. \quad (\text{D.5})$$

The solution of (D.3) takes the form:

$$f(p) = A p^\beta \quad (\text{D.6})$$

where  $\beta > 1$  is the positive root of the the quadratic equation  $\frac{1}{2}(\sigma_P^2 + \sigma_C^2)x(x-1) + (\alpha_P - \alpha_C)x + (\alpha_C - \mu) = 0$ , and the optimal threshold is given by:

$$p^{**} = \frac{P^{**}}{C^{**}} = \frac{\beta}{\beta - 1}. \quad (\text{D.7})$$

We are now able to compute the average time that the process  $p_t$  takes to reach the trigger  $p^{**}$ , starting from a point  $p_t < p^{**}$ . By applying Itô's Lemma to  $\ln p_t$  we get:

$$d \ln p = \left( \sigma_C^2 + \alpha_P - \alpha_C - \frac{1}{2}(\sigma_C^2 + \sigma_P^2) \right) dt - \sigma_C dz_C + \sigma_P dz_P$$

The mean time that  $\ln p_t$  takes to reach the upper trigger  $\ln p^{**}$  for the first time is given by:

$$E(t^{**}) = m^{-1} \log \left( \frac{\frac{\beta}{\beta-1}}{p_0} \right), \quad (\text{D.8})$$

where  $m$  is the constant drift  $(\sigma_C^2 + \alpha_P - \alpha_C - \frac{1}{2}(\sigma_C^2 + \sigma_P^2))$ ,  $p_0 = \frac{P_0}{C_0}$  and the variance is  $Var(t^{**}) = \frac{(p^{**}-p_0)(\sigma_C^2+\sigma_P^2)}{2(\sigma_C^2+\alpha_P-\alpha_C-\frac{1}{2}(\sigma_C^2+\sigma_P^2))^3}$ .<sup>29</sup>

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## Notes

<sup>1</sup>The first Conto Energia was issued with, D.L. 387 2003 and Decreto Attuativo July 28, 2005; the fifth Conto Energia was issued with, D.M. July 5, 2012.

<sup>2</sup>This article outlined three key points for governments and regulators to set a sustainable PV-support program. First, Governments had to “Clarify objectives”, before establishing the support policy, deciding the goals of the public intervention. Second, Governments had to “reward production, not capacity”, creating the incentives to increase cost-efficiency. Third, Governments had to “phase out subsidies carefully”, to avoid creating a vicious cycle after the reaching of Grid Parity.

<sup>3</sup>Different types of plants will reach Grid Parity in different moments.

<sup>4</sup>The annual volatility is around 30% , see Renò (2006) and Dmouj (2006).

<sup>5</sup>See Escribano et al. (2011) and for the Italian case the annual reports by GME (Gestore Mercati Energetici).

<sup>6</sup>Assuming that the state variable follows a lognormal random walk is standard in real-option models. However, alternative processes, such as mean-reverting, can be used. This would complicate the analysis, without significantly changing the results .

<sup>7</sup>The log returns of Italian electricity prices present some border values, which are higher than the standard normal distribution. This is in line with the general observation about the presence of fat tails in different financial time series.

<sup>8</sup>We can easily transform monthly data in an annual data by the following formula:

$$\sigma_{yearly} = \sqrt{12 : \sigma_{monthly}^2}$$

<sup>9</sup>The parameter  $\eta$  can be calculate by using the formula  $-\log(\theta + 1)$ , where  $\theta$  is the coefficient of  $p_{t-1}$  in the regression A.2 in the Appendix A (see Dixit and Pindyck 1994, pp. 74-79)

<sup>10</sup>As Breyer and Gerlach (2010), we are using the end user price to compute our Grid Parity. Clearly, the break even point for industrial or domestic consumers have to be computed on their reference prices.

<sup>11</sup>The values of LCOE depend mainly on the assumptions made for its calculation. For an accurate analysis of costs concerning the photovoltaic power generation plants, it is useful to present the effects of the variation of

single cost component on LCOE. The sensitivity results reported in this paper are taken from the Salvadores and Keppler (2010a) and from Darling et al. (2011)

<sup>12</sup>As matter of fact, a minimum and a maximum LCOE are calculated for each plant size. We take the average to have a single value.

<sup>13</sup>For the sake of completeness, it is important to mention some key methodology assumptions used in both studies. PV modules can be divided in two different categories: thin film modules and crystalline silicon modules. Being this the most diffused on the market, both studies refer only to this category. For the assurance cost, the estimates are based on direct and indirect damages coverage and theft coverage. For the choice of the capacity factor, both works consider 1250 hours of operation per year and a capacity factor of 14-16%. Clearly, being Italy a peninsula with different levels of solar radiations, southern regions have higher capacity factors than the northern ones. This important issue is not at stake in our model. Finally, it is important to underline that taxes are excluded from the computation of the LCOE.

<sup>14</sup>For more details about the learning curve approach see Nemet (2006).

<sup>15</sup>From 2004 to the third quarter of 2008 the price of PV modules remained flat, despite manufactures were making continuous improvements and scale to reduce their costs. This was due to the fact that German and Spanish tariff incentives allowed project developers to buy the technology at those prices. The 18 largest quoted solar companies followed by Bloomberg made average operating margins of 15% Bazilian et al. (2009). When the Spanish incentive regime ended abruptly at the end of September 2008 global demand had a sudden deceleration, while silicon availability increased. This sudden need to compete on prices pushed PV constructors to reduce margins. They were able to drop their prices by 50% and still make a positive margin, given the costs reductions achieved in past years. In addition, following the understanding and comfort of PV deployment risks, financing costs were falling. Nowadays, the recent excess production capacity can push the price to fall to the level of marginal production costs, having important implication on future PV module prices. In Germany Q-cells and Solon have announced bankruptcy between the end of 2011 and April 2012 and the U.S. First Solar closed its European operation in April 2012. For this main reasons, some have argued that prices are below sustainable levels and might even gave to rise slightly. However, technological advancements, process improvements and changes in the structure of the industry suggest that further price reductions are likely to occur in coming years Bazilian et al. (2009)

<sup>16</sup>PV learning curves are computed at module level, because module costs account for nearly a half of the total LCOE.

<sup>17</sup>The progress ratio is equal 1 minus the learning ratio, it express the cost decrease of the future years at each doubling of cumulated output.

<sup>18</sup>In the 2012 "Solar Energy Report", there is a medium term punctual forecast on the possible PV installations for 2012 and 2013. The expectations for 2012 define a 20% increase of the PV market, with the construction of 2,7 GW of new plants. For 2013, taking into account the interactions between the actual "5<sup>th</sup> Conto Energia" and the end of the incentive system, the market is expected to growth by 10%, with 1.475 Mw of new installed plants.

<sup>19</sup>Both *GRs* are adjusted for taking account that (3) expresses the dynamic of LCOE in continuous time.

<sup>20</sup>IEA5 and IEA10 are both referred to the Utility sector.

<sup>21</sup>We work under the assumption of a GBM.

<sup>22</sup>This model is equal to the one used by Breyer and Gerlach (2010)

<sup>23</sup>This result is a consequence of the learning curve which expresses an historical 20% learning rate for the PV industry.

<sup>24</sup>We assume that correlation between (1) and (4) is null throughout the whole analysis.

<sup>25</sup>The equivalent of the GBM in discrete time.

<sup>26</sup>The annualized capital expenditures are obtained trough the use of the capital recovery factor (CRF), the CRF simply converts a present value into a stream of equal annual payments over a specified time period at a given discount rate.

<sup>27</sup>In the study made by the Politecnico di Milano, *O&M<sub>pex</sub>* costs are on average 1,5% of the total costs for PV.

<sup>28</sup>What we do, in practice, is to transform a volume-dependent formula, usually used to express learning curves, in a time-dependent formula, which is more suitable for our analysis.

<sup>29</sup>Obviously  $m$  should be positive; otherwise  $E(t^{**}) = \infty$  (see Cox and Miller (1997) p. 221-222).

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