Feed in Tariff Policy for Microgrids: Past and Future

A Case Study of the Option Value of Complementary Energy Assets in Turbulent Conditions

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ABSTRACT

Purpose – The intermittence of renewable energy sources is a substantial barrier to investments. This issue has conventionally been addressed by governmental policies such as feed-in tariffs. The objective of the paper is to assess the effectiveness of these policies and the implications for investments in renewable energy systems, with a specific focus on systems where hydrogen storage systems are emerging as a viable option.

Design/methodology/approach – A quantitative modelling approach is used to analyse a real-life case study considering renewable energy investments staging options vs. an upfront investment.

Findings – The main finding of the paper is that feed-in tariff policy is of little importance when storage is utilised, as the storage hedges weather related risk for customers. If the microgrid does not have local storage, or still exports substantial amounts of power, then feed-in tariffs are still needed. This implies that policies need updating as the energy sector evolves and the type of support needed becomes more sensitive to microgrid design.

Originality – The paper provides new insights about using real options theory in a context of increasing uncertainty when complementarity between assets exist. It also argues that the historical “one size fits all” design of feed in tariffs policies is ineffective for the future.

Research limitations/implications – Simplifications were made when modelling weather. Normal weather volatility is accounted for, but not large-scale unusual weather patterns.

Keywords Case study, Feed in Tariff, Real options, Decision tree, Renewable Energy, Hydrogen storage

Paper type Case study

Introduction

The United Nations Sustainable Development Goal number 7, affordable and clean energy, is a reminder that despite increasing concerns about climate change, our ability to operate a cost-efficient green energy sector remains limited. Many authors (Penht et al. 2006; Bergman and Eyre, 2011) have proposed that one possible path to achieve clean electricity is to invest in decentralised energy systems. This means investing in microgeneration, i.e. generating energy from renewable sources in micro-grids where the electricity is then used. Investments in micro-grids predate most of today's large-scale renewable energy installed capacity. Therefore, the critical impact that the intermittence of renewable energy sources has on the value of microgeneration investments was experienced many years ago. Intermittence aggravated the high cost of renewable energy generation technologies, often resulting in individuals or firms concluding that investment in microgeneration were not worthy. This reluctance to invest was overcome by feed-in tariffs (FiT). If a power generation technology is expensive, it is important that the generation asset is utilised as much as possible. In the instance where local generation exceeds local demand, the excess power generated is exported to a utility grid that pays the microgrid according to a tariff set by the policy. Attractive rates resulted in an increased willingness to invest.

If we fast-forward 18 years to today, FiT rates have decreased significantly or have often been terminated. For example, in the United Kingdom, the country of this paper's case study, the initial FiT rate set by the *Energy Act 2008* for microgeneration was around 40 p/kWh. It was revised in 2011 (21 p/kWh) and 2012 (16 p/kWh). As a result, many UK-based solar installation firms ceased to trade as investing in microgeneration were becoming less attractive. The scheme was stopped in 2019 and replaced by a Smart Export Guarantee of 7.14 p/KWh that rewards the use of smart meters to export power when it is needed, by opposition to an unconditional fee. This decrease and evolution in FiT rates have been observed in many other countries (see for example Skrypnyk et al., 2023 for Ukraine, Yu et al., 2022 for China, Poruschi et al. 2018 for Australia).

There is a rationale for this universal pattern of decreasing, replacing, or withdrawing FIT policies, as shown in figure 1. The value of an investment in local generations is a function of three key variables. Cheap technology costs increase the value of microgeneration as the resultant levelised cost of electricity (LCOE) is cheaper than electricity retail prices. This relation is threatened by weather volatility, but this can be offset by high export tariffs, which limits the loss of value linked to unused local generation. Finally, the value of microgeneration increases as retail electricity price (an opportunity cost in this case) increases.

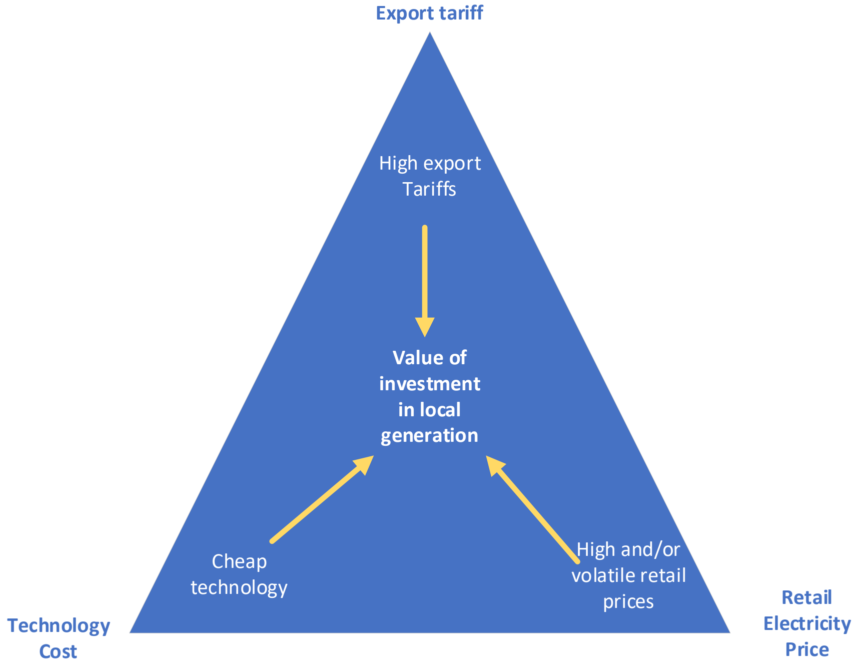

Figure 1. The Determinants of the Value of Investing in Microgeneration Assets (Source: Authors' own work)

The motivation for writing this paper is to assess the value of microgeneration from an engineering economy perspective, and this, in today's context, as this context is fundamentally different than 20 years ago. When compared to the initial wave of investment in microgeneration linked to original FiT policy instruments (2006-2010), the context of investing has indeed changed significantly:

1. Technology costs has decreased significantly and renewable microgeneration generation LCOEs are usually cheaper than retail electricity prices.
2. This means that there is no need for export tariffs, i.e. the technologies are cheap enough to be valuable investments. Thus, one of our research questions is: do FiT policies really matter? Or are they not needed any longer?
3. However, FiT rates were an important risk investment reduction mechanism. By removing this mechanism, risk has been increased. Therefore, a second question is: how do low, or zero, FiT rates affect the value of microgeneration?

4. To address this risk in the absence of FiTs, a solution is to invest in energy storage. Instead of exporting excess power, it is stored on site for future use. However, energy storage increases the technology cost, and thus reduces the value of the investment, especially if storage is poorly utilised. This raises another question about the impact of value of investing in generation and storage at the same time?
5. Finally, today's context is characterized by an increase in geopolitical conflicts and concerns about fuel security and climate change. All these external variables result in increasingly volatile electricity retail prices. Mosquera et al. (2008) argue that the "*energy industry is boiling over with change*". How does this increased volatility impact the value of microgeneration assets?

The objective of this paper is to focus on the relevance and importance of microgeneration FiT policies in modern electricity systems. Are FiTs a thing of the past, or do we still need them? FiT policies have usually been based on a "one size fits all" approach, i.e. all microgeneration sites are the same and therefore are supported in the same fashion. As technologies evolve and emerge (e.g. big data, industry 4.0, smart grids, energy storage), do we need more adaptable policies?

The next section review reviews the FiT policy literature to confirm the topicality of our research problem and motivation. After the literature review, we introduce the engineering economy framework required to assess microgeneration investment value.

A review of feed-in tariffs policies

Long et al. (2024) performed a systematic literature review of financial mechanisms used to support energy transitions. They classify mechanisms in six groups: public financing, private financing, market-based mechanisms, innovative financing mechanisms, risk mitigations instruments, and institutional support (including capacity building).

Long et al. (2014) classify FiT policies in the market-based mechanisms. Although FiT tariffs are clearly set and evolve in relation to supply and demand, as a policy instrument, they also achieve a significant risk mitigation role, and this in two ways. First, FiT often contains a rate guarantee. When the rates are changed, this normally only applies to new installations.

Second, should the weather be such that it creates a disconnect between microgrid consumption and production, the rate kicks in to offset this disconnect.

In a survey of European and North American investment professionals, Burer and Wustenhagen (Bürer and Wüstenhagen, 2009) show that FiT policy is viewed as the most effective and preferred renewable energy policy. Many scholars confirm this conclusion and show that a well-designed FiT system encourages a deployment of renewable investments in the shortest amount of time and at the lowest costs for society (Le et al., 2022; Haas *et al.*, 2011). Looking at the specific case of Vietnam, the third largest market for solar photovoltaic energy in 2020, Le et al. highlight the critical importance of FiT for regions with low irradiance. In contrast to short-term trading for green certificates in financial markets, FiTs reduce investors' vulnerability by killing two birds with one stone: low market prices exposure is removed by guaranteeing a predetermined payment per unit of electricity generated, and the negative economic consequence of intermittence are avoided by increasing utilisation. For this reason, FiT policies have been an essential part of the investment landscape, and Gatzberg and Kosub (2017) classify them as a policy and regulatory risk factor to be used when considering renewable energy investments. Long et al. (2024) confirm the latter in the conclusion of their systematic review as they explain that instability of financial support mechanisms remains a major challenge to the clean energy transition.

Policy researchers are therefore very positive about FiT policies. Some even argue that they should be extended beyond their main purpose, i.e. facilitating the transition to green energy. For example, Eyre (2013) argue that the UK should introduce an energy saving FiT that encourages energy efficiency improvements.

If there is a consensus on the importance of FiTs to incentivise the clean energy transition, why are they almost systematically being withdrawn?

A first answer to this question is the argument that there are cheaper mechanisms to lower carbon emissions. Poponi et al. (2021) argue, in the case of Italy, that the same carbon emission reductions could have been achieved at a lower cost with energy efficiency measures. Although an important conclusion, it remains a moot point as green power generation and energy efficiency are not mutually exclusive mechanisms.

Pyrgou et al. (2016) provide a second answer to the question above by using data from the FiT schemes of Denmark, Germany, Cyrpus, and Spain in a quantitative model that explains the collapse of FiT schemes. FiT schemes have basically been victims of their own success. For example, Pyrgou et al. (2016) argue that collapse of the schemes in Cyprus and Spain was because the uptake of renewable energy was so high that they started to generate a net cost to energy systems. Their conclusion is to encourage more flexible schemes, where FiT rates are adjusted dynamically as energy markets and generation rates evolve. Therefore, Pyrgou et al. (2016) highlight the importance of our main research question, i.e. can we continue to rely on "one size fits all" schemes?

Valuation framework: A real options theory perspective

An evaluation of the impact of FiT policies on the value of microgeneration cannot be reduced to FiT as single variable. The three key variables shown in figure 1 (FiT rate, technology cost, electricity price) are interdependent. Typically, the evaluation of an investment in microgeneration will be assessed with discounted cash flows techniques, such as the Net Present Value Method (NPV; see Camilo et al., 2017 for an example of residential PV systems with storage). The rest of this section explains why, in the context of investments characterised by multiple sources of uncertainty and different ways of flexibly configuring an investment, real options valuation approach is better suited than discounted cash flow approaches.

In 1976, for the first time, the concept of embedding option values in management decisions was proposed by Dan Galai and Ronald W. Masulis. They established a combined model of capital asset pricing and financial option pricing (Galai and Masulis, 1976). In his paper published in 1977, Stewart Myers defined options written on physical company assets as "real options" (Myers, 1977). As real options theory became more widely used, criticism of other methods increased; several contradictions in the use of discounted cash flow analysis in strategic planning were documented, and real options became the recommended approach to perform strategic investment analysis (Myers, 1984). As a result, real options analysis is now widely employed in various disciplines, including oil extraction, strategic planning, manufacturing, property investment, R&D, governed organizations and utility companies, inventories, supply chains, advertising, and a variety of others.

Park and Herath (2007) provide an account of this paradigm shift by describing real options theory as a new way of thinking in engineering economy. Instead of modelling uncertainty as a variable having a negative impact on the estimated value of an investment, the real options approach encourages decision makers to keep their options open, as uncertainty as a construct encapsulates downside risk (which reduces the value of an investment) but also upside potential (which increases the value of an investment). Park and Herath conclude that conventional investment techniques work well for investments that are stand-alone and non-deferable with low uncertain cash flows. However, if parts of an investment decision can be deferred until more information becomes available, the real option valuation approach provide a better assessment of value. This is because by deferring parts of the investment decision, uncertainty has been reduced and management decision can be flexibly adjusted when a changed condition update becomes available. This link between real options and flexibility has been a main feature of the research literature (Trigeorgis, 1996; Schwartz & Trigeorgis, 2004). Bowman and Moskowitz (2001) provide an example of the application of this approach with a case study from Merck that clearly articulates the distinction between the purchase of an option and the subsequent decision whether or not to exercise this option. In their review, Driouchi and Bennett states that: "*In theory, real options offer flexibility, resource and the capability to benefit from the uncertainty surrounding businesses*" (p. 39; 2012). As investments in renewable energy systems are large scale economic commitments facing considerable uncertainty, real options theory provides an ideal framework for their valuation by considering the uncertainty-flexibility relationship and the commitment-flexibility relationship (Driouchi and Bennett, 2012).

As a result, many renewable energy researchers have used real options theory to evaluate investments in renewable energy systems. For example, Santos et al. (2014) provide a comparison of discounted cash flow techniques versus real options with a case study of an investment in a mini-hydro plant. They conclude that the real options approach is better and creates a greater awareness of decisions that can be deferred. Fernandez et al. (2011) review of the literature on non-renewable energy systems reaches the same conclusion. Another example is the appraisal of a hydropower case study where, again, the benefits of a real options approach are confirmed and are extended to considering different design decisions (rather than solely managerial options) as well as optimal timing decisions (Martínez-Ceseña and Mutale, 2011). Loncar et al. provide an example of an empirical application of considering several options with a compound option set (expand, repower, contract, and abandon) for an offshore wind farm case study which considers a FiT contract within the model (Loncar *et al.*, 2017). In a literature review, Kozlova (2017) also recommends considering project design options and she lists the different possible options that are being researched. She also reveals that electricity price and technology are considered as the top two uncertainty factors considered by researchers and that the timing of investment is a research issue in 60% of her sample, followed by the decision to invest in a system (23%) or abandon a project (18%). She also shows that real options are used in the design of support policy for renewable energy systems. Kozlova's review is useful in drawing a typical portrait of the real options research that has been performed to date: concern is expressed about the high level of uncertainty, typically with the market electricity price and technology performance. For this reason, investment in renewable energy systems rarely provide any value according to traditional investment evaluation techniques. Using a real options approach, more value is revealed, typically by postponing investment decisions or staging a project into sub-projects.

This paper departs from this now well-established conclusion. None of the research to date has considered the option to store electricity as part of one of the system design decisions. Considering storage has two implications. The first is that, in a context of ever-decreasing feed-in-tariffs, storing electricity may not need to be a postponed decision, as storing electricity could provide a better benefit than using the tariff. This means that instead of looking at options that create value from deferral, we look at value creation from bringing a decision forward, i.e. an "option to expedite" an investment. The second implication is that by not considering storage, investments in systems suffering from intermittence will always be under-valued as intermittence increases downside risk. The fact that the value of a renewable power generation asset is dependent on a complementary asset (energy storage) connects our research with a recent research advance in real options theory, advance that goes beyond the traditional flexibility and commitment relationships with uncertainty.

Leiblin et al. (2016) argue that real option theory can be used to understand value creation in strategic factor markets by accepting that managers face uncertainty about the current and prospective value of assets. Their argument is that when managers better understand the complementarities between different assets, they are better able to process information about these assets, know when to exercise options, and they are able to gain a source of competitive advantage that competitors have missed. This is because managers saw value within an asset when other investors only perceived high value uncertainty.

The next section presents how a case study was designed to explore this complementarity dynamics.

Methodology

In order to explore how uncertainty about electricity price and FiTs create valuation uncertainty for an investor when a complementary asset is available, we use a case study of an industrial firm. The case study is based on a real (anonymous) firm (named X in the rest of the paper) and used real cost and engineering data about commercially available generation and storage technologies. The organisation was selected for its energy intensive process, making it particularly vulnerable to fluctuations in the price of electricity. In the case study, we explore the value of an investment aiming to make firm X grid-independent by using renewable energy sources and storage. The method used in this paper is model-based research (Bertrand et al., 2023; Bertrand and Fransoo, 2002). We explore, in the context of our case study, what the value of an investment in microgeneration would be and explore the sensitivity of this value to the three variables shown in figure 1.

Case study

The analysis investigates the impact of firm X investing in a solar photovoltaic (PV) system on their factory roof and onsite wind turbines. To become grid-independent, a hydrogen storage solution is considered as well. When excess electricity is produced, an electrolyser produces hydrogen. This hydrogen is then compressed and stored in a tank. When supply from renewable sources is low, stored hydrogen is converted into electricity with a fuel cell.

The design principle was that the average power supply should be equal to the daily demand of firm X (2760 kWh/day). This is achieved by selecting the number of turbines and solar PV panels that achieve the required level of output at an aggregate level (rather than hourly) level. The storage was designed to only buffer the resulting one-day variability caused by the intermittent nature of wind and solar power.

Investing in renewable generation can be complex in terms of planning permission, but we did not consider this aspect, as our research question is purely about exploring the value impact of complementary technologies (thus we ignore both zoning and space constraints). We collected real-life solar irradiance and wind data and defined a base case as the average value of irradiance and wind at different times of the day, modelled as a set of 1-

hour time intervals. We assume demand to be constant within the day as firm X runs a continuous process. This also allows us to focus on supply side intermittence issues. Our real-life data also captures the complementarity between solar and wind sources, e.g. wind picks when the sun drops, and vice-versa.

System Balancing Rules

Given the parameters of an average day, and the technical characteristics of all the assets, our first step is to characterise, for each time interval, the system energy balance. Once the system is balanced, it is possible to compute the life cycle cost and the levelised energy cost (using a 25 year system life) as well as autonomy from the grid, as illustrated in figure 2.

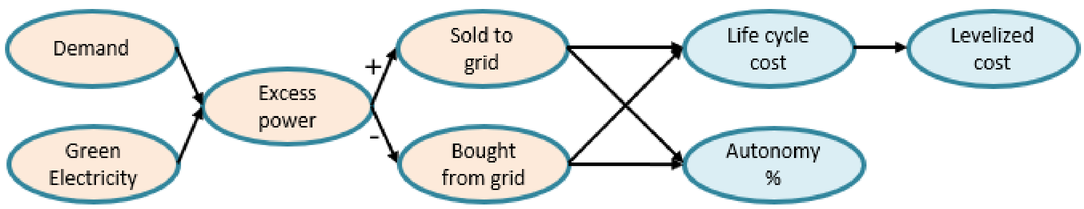

Figure 2. System balancing step

The following equations (1,2) were used to balance the system.

1- In case of no storage (Eq. 1):

$$\mathbf{S + W + Gb = C + Gs} \tag{1}$$

2- In case of storage (Eq. 2):

$$\mathbf{S + W + Stc = C + Sts} \tag{2}$$

Where **S** is the electricity produced from solar source, **W** the electricity produced from wind, **Gb** the electricity brought from the utility grid, **Gs** the power sold to the grid, **C** the local electricity consumption, **Stc** the energy consumed from storage, and **Sts** the energy stored.

Based on the typical day weather data that we use storage builds up in the first two thirds of the day and is used to compensate for lower power generation in the evening and at night. A round-trip efficiency of 60% is assumed for the hydrogen storage system.

Consistently with Steffens and Douglas (2007) we do not consider a base case along with a set of "add-ons" real options, where each new option adds to the value of the initial investment. Instead, we consider from the outset a range of different investment decision sequences, some of them with embedded real options. This means that the system balancing needs to be performed for each different investment scenario.

For each scenario, yearly cash outflows $\mathbf{CF_i}$ are calculated according to Eq. 3:

$$\mathbf{CF_i = TFC_i + TVC_i} \tag{3}$$

where $\mathbf{TFC_i}$ are the total fixed technology costs and $\mathbf{TVC_i}$ the total variable technology costs.

Total fixed costs include the cost of the turbine and the solar panels (inclusive of estimated civil engineering costs and installation). As some scenarios require storing and releasing energy, they also include the cost of a hydrogen compressor, hydrogen storage tank, electrolyser, and a fuel cell system. Variable costs include the cost of electricity brought from the grid after a deduction of the electricity sold back to the grid, and the variable operations and maintenance cost of the system. For the final year, the fixed cost flows include a terminal value to account for any discrepancy between the useful life of assets and the duration of the project. The discounted Levelised Cost of Energy **LCOE** (LCOE; in £/kWh) is calculated through Eq. 4 for each decision scenario, where **r** is the discount rate, **D** the annual demand, and **N** the duration of the project in years:

$$\boldsymbol{LCOE = \frac{\left(\sum_{i=0}^{N} \frac{CF_i}{(1+r)^i}\right)}{N.D}} \tag{4}$$

<u>Valuation Approach</u>

The real options literature can differ widely in terms of how the value of an option can be computed. It is important to remember that historically, real options were defined as an extension of financial options. Therefore, many of the valuation models used for real option valuation find their root in financial modelling. The Black and Scholes model (Black and Scholes, 1973) provides an analytical formulation through which the value of an option can be computed and is often considered as "the best" valuation approach. However, it is important to remember that this model was designed to account for market uncertainty, i.e. the volatility of a traded stock, and as such it assumes that the value of the stock is log-normally distributed. This assumption is often debated in finance, and there is very little reason to believe that either electricity prices or the value of power generation assets is log-normally distributed.

The second most popular valuation approach is the simplified approach for option pricing, the binomial model. The main assumption is that the price of the asset can go up or down within every time increment, resulting in the typical representation of a recombining lattice. This provides a sound and more general model of the volatility of a traded stock, but it does not match well the volatility characteristics of electricity prices, FiT, and real asset values.

Finally, the last valuation method is the use of decision trees. In some cases, authors recommend a hybrid approach between traditional decision trees and the binomial method, i.e. using binomial decision trees (Brandão *et al.*, 2005) as binomial decision trees provide a more realistic model of underlying uncertainty when managers face multiple uncertainties and concurrent options. For other authors, this idea is extended to argue that the real nature of uncertainty faced by managers is more complex and discrete in nature (Mosquera *et al.*, 2008). Steffens and Douglas (2007) use a decision tree valuation approach as it offers a perfect way to model the intertwined relationship between uncertain variables and the different integral options to the decisions to be made. This is not to say that there are no conditions when more traditional methods could be used (for example, the valuation of an oil exploration project is linked to oil price uncertainty, a traded commodity), but these conditions do not apply in this paper, as shown in the next section.

Decision Model

As investing in such a system would be a radical departure from the normal investments of company X, all possible decision sequences are considered from the outset of the project. When real options are embedded in the decision tree, it means that one branch will capture the best expected value and point decision makers to the right option start. The decision model is a tree structure divided into 12 main groups (labelled by their branch number B_i) of decision sequences, which is shown in figure 3. The project duration of **N**= 25 years is divided into three stages. The first stage is a decision/commitment made today, the second stage is a decision made 5 years later, and the third stage starts after 10 years. The 12 decision sequences are shown in Table 1 and Figure 3.

Branch	**Description**
B_0	Decision to rely solely on national grid supply.
B_1	Decision to invest in solar PV only.
B_2	Decision to stage, where the first stage is to implement the PV system and the second stage is to implement the wind turbines.
B_3	Decision to stage, where the first stage is to implement the PV system and the second stage is to implement the wind turbines plus hydrogen storage.
B_4	Decision to stage, where the first stage is to implement the wind turbines and the second stage is to implement the hydrogen storage then PV system.
B_5	Decision to stage, where the first stage is to implement the wind turbines and the second stage is to implement the hydrogen storage plus PV system.
B_6	Decision to stage, where the first stage is to implement the wind turbines and the second stage is to implement the PV system then hydrogen storage.
B_7	Decision to stage, where the first stage is to implement the wind turbines plus hydrogen storage and the second stage is to implement the PV system.
B_8	Decision to stage, where the first stage is to implement the wind turbines plus hydrogen storage and then nothing.
B_9	Decision to stage, where the first stage is to implement the wind turbines plus PV system and the second stage is to implement the hydrogen storage.
B_{10}	Decision to stage, where the first stage is to implement the wind turbines plus PV system and then nothing.
B_{11}	Decision to not stage, i.e. investing 100% upfront.

Table 1. The 12 Branches of the Decision Tree (Source: Authors' own work)

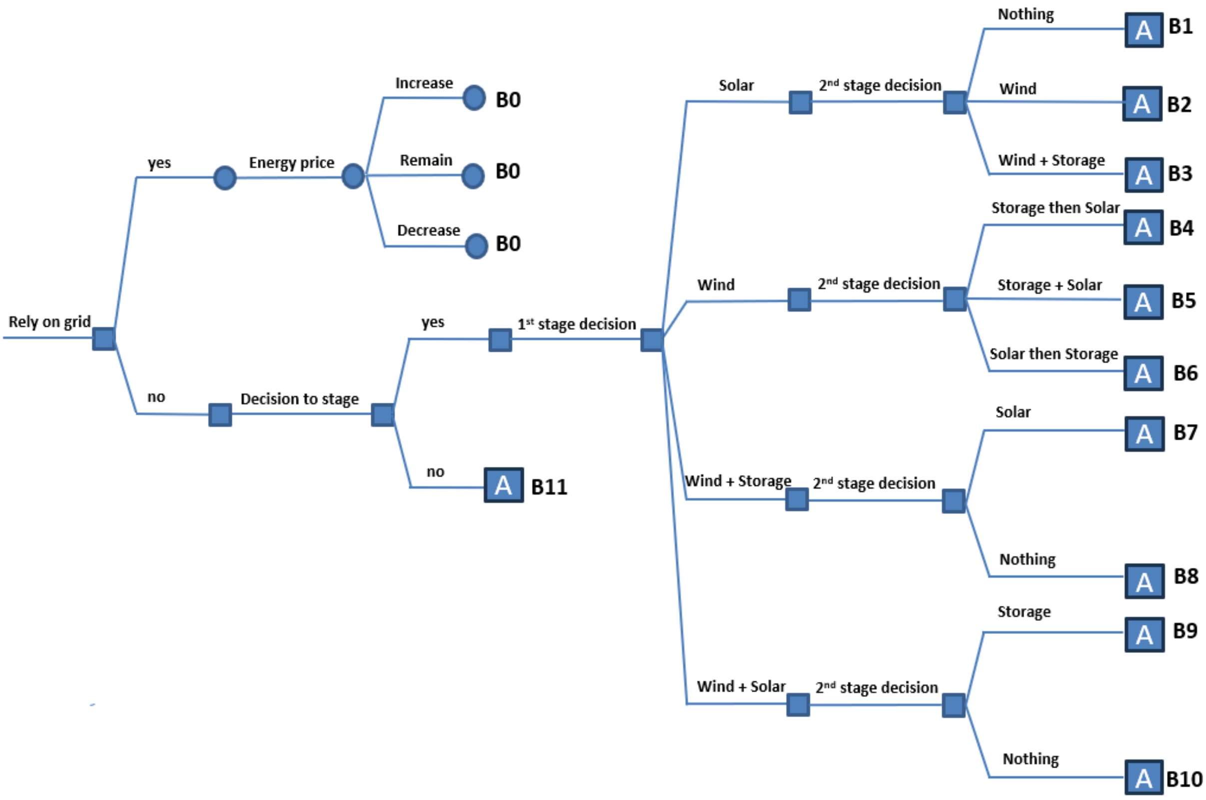

Figure 3. Decision Tree Structure (Source: Authors' own work)

Uncertainty is modelled with the following parameters:

- Price uncertainty applies to the industry electricity rate and to FiT, as shown in figure 4, resulting in 9 possible outcomes for each B_i branch of the tree (i.e. the full tree contains 108 sub-branches).
- Three separate uncertainty scenarios are considered, as described in table 2 (in the first analysis, we set FiT as a constant at 5 p/kWh). Scenario 1 represents a certain and constant electricity price to establish a base case. Scenario 2 captures the most likely "risky" scenario: that of a likely significant increase in the future, but eventually, conditions return to normal (i.e. the prices in scenario 1). Scenario 3 captures the case of a likely and sustained increase in electricity price.
- Discount rates values of 0, 5, and 10% p.a. are considered. Although a discount rate of 0% is impractical, including it in the model is useful to illustrate the

impact of the discount rate on the value of each branch. The 5% rate is used to represent a subsidised investment rate; whereas the 10% value represents the typical competitive rate experienced by an industrial company.

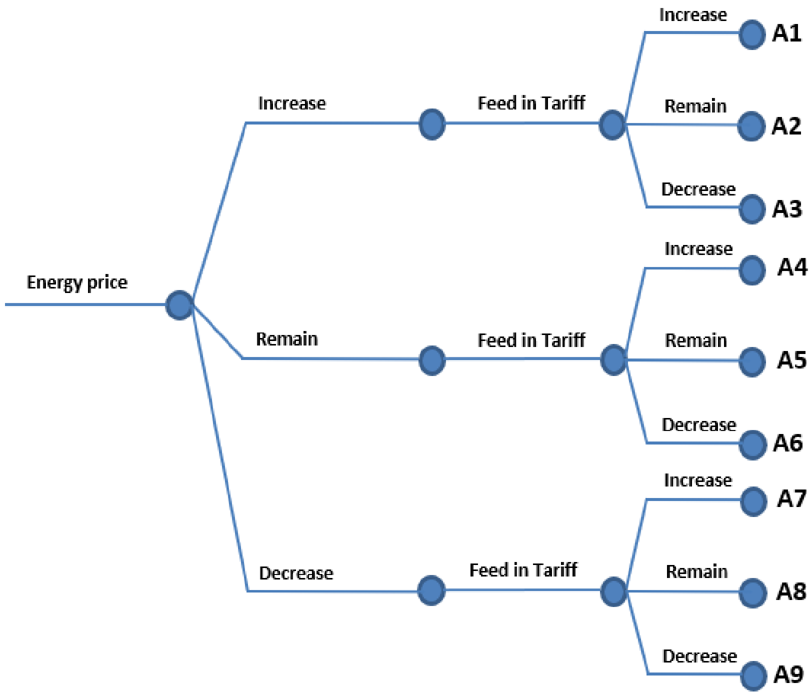

Figure 4. Sub-Tree Structure for Price Uncertainty (Source: Authors' own work)

Scenario	Description	Price_High (p/kWh)	Price-Most Likely (p/kWh)	Price-Low (p/kWh)
1	Base case - current price for industry user, no uncertainty.	0.25	0.25	0.25
2	Significant increase in price, followed by a return to normal.	3	0.71	0.5
3	Significant increase in price, maintained	3	0.71	0.5
	Associated probabilities	0.8	0.18	0.2

Table 2. Scenarios Assumptions (Source: Authors' own work)

The expected energy cost of each branch (EC_{Bi}) is computed with equation 6, where P_j and Q_k are the subjective probabilities associated with price and FiT uncertainty, respectively:

$$EC_{B_i} = \sum_{j=1}^{3}\left(\sum_{k=1}^{3} P_k Q_j LCOE_{i,j,k}\right) \tag{6}$$

The following P_i probabilities were used: 80% probability of an increase, an 18% probability of not changing, and 2% change of a decrease. The Q_i probability were all sets at 33%.

We do not compute the financial value of the subsets of the assets. Instead, we use EC_{Bi} to solve the decision tree and identify the best decision sequence, assuming a constant FiT price. We then select the branches with the lowest ECB_i to narrow the decision of these branches and define the value of investing in green power generation, the value of staging options, and the value of investing in storage. More details are provided in the following section.

Results

Table 3 shows the results of the analysis and that the decision sequence B10 (invest upfront in wind and solar generation, but not storage) achieves the best results overall. Branch B11, the full upfront investment, underperforms B10, but often by a very small margin.

Doing nothing (branch B0) only outperforms other decisions if electricity prices are low and certain (scenario 1), there is no inflation, and the discount rate is high. This is shown in Table 3 for the sake of illustrating the dynamics between the different variables, but it is clearly based on a set of impractical assumptions. This observation can however be generalised by stating that in a period of low prices and economic stability, not investing in anything or investing small amounts pays off (see the good performance of B0, B1, and B6 in scenario 1 for different discount rates). These are the instances where the options to stage, to wait would be used.

The dynamics between variables can be summarised as follows, bearing in mind that the model was designed around constant British weather (this limitation is discussed later):

- Doing nothing (B0) puts firm X in the most exposed position in terms of risk: this can be observed as the largest difference between scenarios 1, 2, and 3. All other options decrease exposure to electricity price risk. A higher discount rate attenuates this exposure as future payments of electricity have a lower present value.

	Discount rate = 0%			Discount rate = 5%			Discount rate = 10%		
Decision Sequence	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
B0	0.25	0.71	2.08	0.14	0.45	1.03	0.09	0.31	0.57
B1	0.24	0.73	1.99	0.15	0.5	1.07	0.11	0.36	0.65
B2	0.2	0.78	0.78	0.16	0.59	0.59	0.12	0.45	0.45
B3	0.21	0.21	0.21	0.18	0.18	0.18	0.15	0.15	0.15
B4	0.2	0.42	0.42	0.14	0.25	0.25	0.12	0.18	0.18
B5	0.19	0.19	0.19	0.15	0.15	0.15	0.12	0.12	0.12
B6	0.19	0.33	0.33	0.13	0.23	0.23	0.11	0.17	0.17
B7	0.19	0.19	0.19	0.15	0.15	0.15	0.13	0.13	0.13
B8	0.2	0.2	0.2	0.15	0.15	0.15	0.13	0.12	0.13
B9	0.19	0.19	0.19	0.14	0.14	0.14	0.12	0.12	0.12
B10	0.19	0.19	0.19	0.14	0.14	0.14	0.12	0.12	0.12
B11	0.18	0.18	0.18	0.15	0.15	0.15	0.13	0.13	0.13

Table 3. Results of the analysis, showing the LCOE for company X over 25 years in £/kWh. The red values show the decision sequence achieving the best LCOEs for each scenario (feed in tariff is set at 5 p/KWh; Source: Authors' own work).

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- Investing large amounts upfront (e.g. B9, B10, B11) mitigate this exposure. These decision sequences are equivalent to signing a 25-years forward contract for electricity prices (bearing in mind our constant weather assumption).
- Solar PV, due to its limited capacity when compared to demand, has only a minor impact when compared to doing nothing (difference between B0 and B1).
- All the staging options end up being compromises being doing nothing (B0) and expediting investments (B9, B10, and B11). Within these options, staging only has a minor impact. This is a departure from the traditional real options literature that typically advocates to wait, postpone, or stage.
- An increase in discount rates further decreases the impact of staging investments.

Based on these results, the rest of this section will narrow the analysis on branches B0, B9, B10, and B11 in order to further describe the dynamics between price uncertainty and the discount rate, as shown in Figure 5.

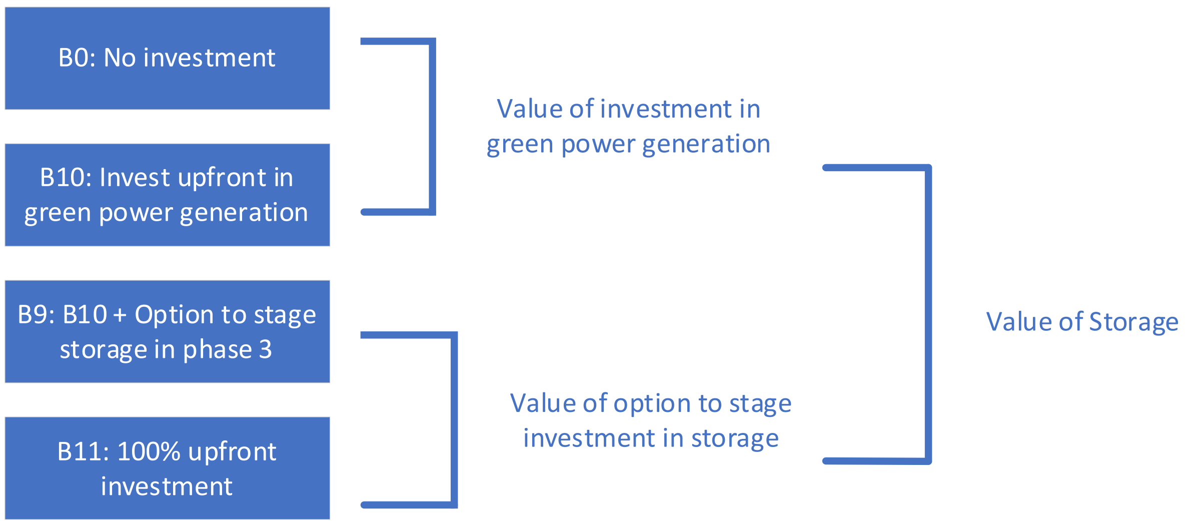

Figure 5. Defining the different values of investing in the energy system (Source: Authors' own work)

The sensitivity analysis for the results shown in Table 3 are performed under a discount rate of 10% (the most realistic cost of capital for an industrial company) and scenario

2. If a business is concerned by a high and sustained increase in electricity price (scenario 3), the decision to invest in renewables energy source is easy to make as these sources become competitively priced. The case in which a company will struggle to make a decision is when it expects an important price increase in the future that will not be sustained, i.e. a short-term energy crisis (scenario 2).

Figure 6 displays the sensitivity analysis of the 3 value measures (i.e. LCOE as a proxy to measure value) as defined in figure 5 according to the high value (Ep+) of possible future electricity prices. The mid-point and low values, and the FiT rate, are kept at their base case value.

Figure 6 shows that investing in green power generation becomes more valuable as the market price (Ep+) increases. Using storage presents the advantage of "locking-in" electricity prices but the required investment means that investing in storage decreases value. The option to stage the investment in storage is in the money, as the investments is postponed to a later date and thus is cheaper in present value terms.

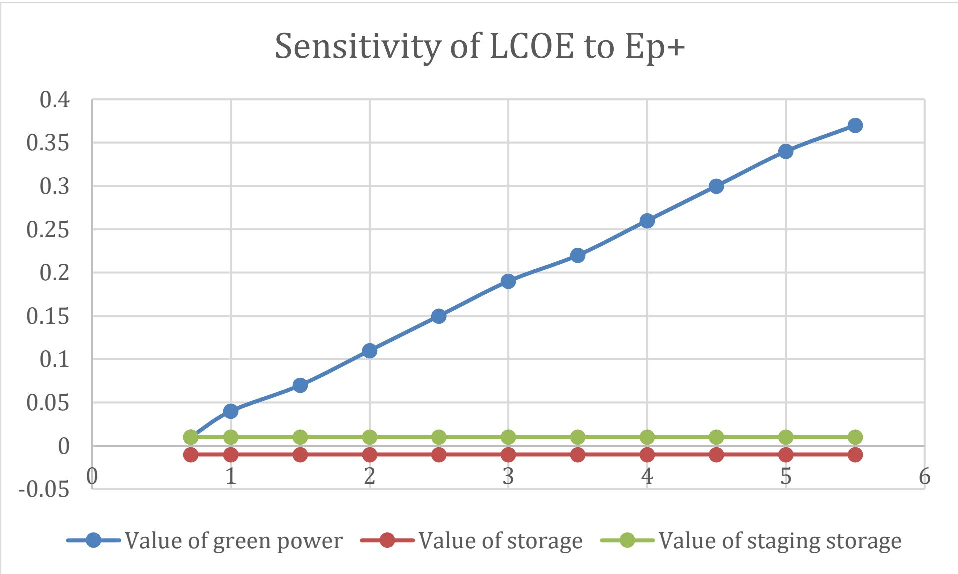

Figure 6. Sensitivity of value to Ep+ (Y= LCOE in £/kWh and X= Ep+ in £/kWh) (Source: Authors' own work)

Figure 7 is based on setting Ep+ to the base case value of £3/kWh and illustrates a sensitivity analysis of value to the FiT rate. The results are sensitive to FiT and the value of green power generation increases with higher FiT rates. The results shown in figures 6 and 7 confirm why historically, investments in renewable energy had to be supported by attractive FiT tariffs.

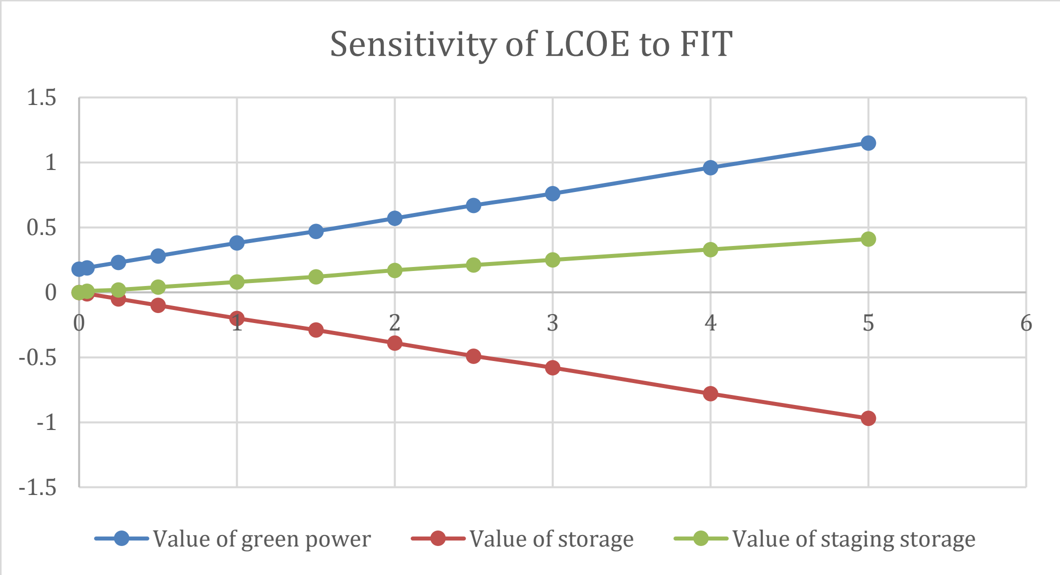

Figure 7. Sensitivity of value to FiT value (Y= LCOE in £/kWh and X= FiT in £/kWh) (Source: Authors' own work)

Figure 7 also shows that the value of storage is increasingly negative as FiT rates increase. This is because the model captures the opportunity cost of not being able to sell excess power production at the higher rates. This effect is mitigated by using the option to stage the investment in storage. In practical terms, an investor would keep the option open during the energy crisis and upon realising that the electricity prices are decreasing, the investor would not exercise the option (this is not shown in figure 7).

Figure 8 presents the sensitivity analysis of investment value to the cost of investing in storage. For ease of presentation, we compute a levelised cost of hydrogen (LCOH) generated (in and out of storage) over the full lifecycle. The base case value is 4.22 £/kg.

For high values of the cost of hydrogen, it is not worth investing in the storage system. The indifference point between investing or not investing in storage is 2.11 £/kg, half of the base case value. Figures 6, 7, and 8 together shows that *without* storage, FiT policy does matter. With storage, FiT policy does not matter. It is important to note that our levelized cost of hydrogen (LCOH) in figure 8 does not include generation costs as normally specified in the literature. Instead, it represents the cost of the full storage system (electrolyser, tank, and fuel cell) as the cost of generation is accounted for elsewhere in our model.

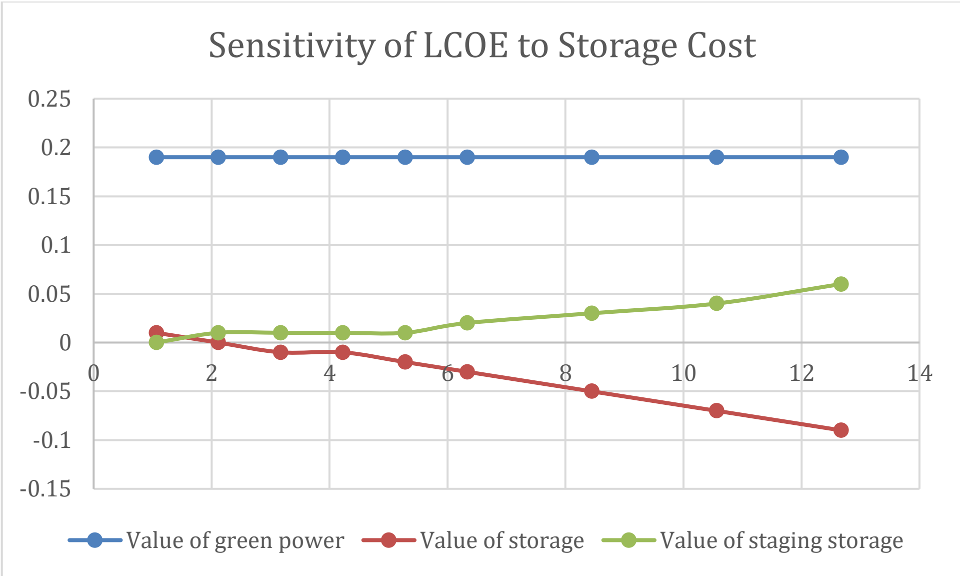

Figure 8. Sensitivity analysis of value to storage cost (levelized storage cost in £/kWh; scenario 2, discount rate = 10%, Ep+ =3 £/kWh, FiT = 5 p/kWh)

(Source: Authors' own work)

Discussion

The paper has important implications for real options theory as it reverses the tendency to justify investments by postponing decisions. Instead, the case study shows that firms can consider the option to expedite an investment. The traditional ultimate performance metric, the value of the staging option, is negative in our case study as soon as electricity price passes a not-so-distant threshold.

It also has implications for policy makers as it suggests that the presence of storage as a complementary asset means that FiT may become redundant should energy prices continue to increase. The major challenge of a successful FiT policy has always been to continue guaranteeing that the FiT payments are sufficient to cover project expenditures throughout the course of the project while allowing for a good return (Klein et al., 2008). This is especially useful for funding equity projects with high start-up costs or with a high percentage of fixed to variable costs (Couture and Gagnon, 2010). As shown in this paper, this entire logic will change when a complementary storage asset is introduced. Hydrogen storage creates value not only by creating immunity to the variability of electricity price *and* FiTs, but also by increasing the value of the renewable energy assets.

Flexible assistance for investors in the renewable energy industry is necessary, contingent upon the architecture of the microgrid system. Certain microgrids might profit from the FiT policy, particularly if designed to generate income from a substantial quantity of exported electricity (microgrids with no storage). Other microgrids might benefit from other types of subsidy mechanisms, such as low interest loans or direct subsidies. This is the case for microgrids with storage systems. A flexible balance is needed to encourage more microgrid design diversity, with each type of design better serving the specific needs of industrial consumption nodes. If the promotion of autonomous microgrids is to be supported, as suggested by most of the current research that considers autonomy a performance metric (Mallick et al., 2024; Sánchez et al., 2024), then the current "one size fits all" FiT policies are the most effective instrument. However, other authors advocate the establishment of more collaborative microgrids (Feleafel et al., 2024, Sato et al., 2017) that seek to decrease the volatility of orders placed to the utility grid. The downside of this approach is to increase the excess power generated by the microgrid. This illustrates a case when FiT policies remain useful in their current form, even though an investment in storage has taken place. Given the fact that a collaborative microgrid is increasing its cost to ease pressure on a utility grid, it makes sense to argue that the tariffs received should include some form of compensation, i.e. be different from the tariff received from a microgrid with no storage at all. These ideas are summarised in table 4, illustrating the different implications for policies.

It is however important to note that even though our most important contribution is to characterise the interplay between FiT, electricity price, and storage capacity, we did not explore this interplay by considering medium- and long-term weather variability, which remains an important direction for future research. Similarly, aside from the solar PV system, none of the assets considered in our model have experienced full cost reduction from learning curves. However, our findings can be generalised beyond our case study, which is based on a within-day balancing of local generation with consumption through storage. In order to extend our model to longer time horizons, the investment in storage will have to be increased but storage utilisation will decrease. This is not a desirable investment proposition when storage is still an expensive addition to the design of micro-grids, so the needs for policy support increases as we generalise the design of the case study. It is only as the LCOH decreases by experiencing technology learning curves that the need for support decreases.

Type of microgrid investment	Microgrid design objectives	Microgrid impact on utility grid	Recommended policy instrument
Autonomous or "selfish" microgrid without storage.	Achieves independence from the grid whilst remaining connected for backup purposes.	Export of low quality and volatile green power. Volatile orders to grids for backup purposes.	FiT is required to generate income from exported power.
Autonomous or "selfish" microgrid with storage.	Lock in price of electricity by maximising autonomy. Storage provides the equivalent of a forward contract on electricity prices.	Export of low quality and very sporadic green power.	Storage investment best supported by subsidies. FiT not required, unless exported power is substantial (It is not in the case study used in this paper).
Collaborative microgrid with storage	Generate green power locally and create a stable electricity order regime to the grid.	Smooth stable demand, with rare backup power needs. Export of good quality green power.	Storage investment best supported by subsidies. FiT is required as a fair compensation for collaboration and quality of exported power.

Table 4. Illustration of the principle of contingent FiT policies.

If the issue of weather volatility is set aside, an emerging question is why are firms not systematically investing in renewable energy? The cost of the technologies is not a barrier any longer and the only remaining two reasons to explain a reluctance to invest is (i) capital rationing and (ii) risk profile. Investing in a renewable energy system with storage means paying electricity bills upfront, but it assumes that this investment is possible. If it is not, then firms can either do nothing or consider staging options that offer lower returns. In their review of green electricity financing mechanisms, Long et al. (2024) conclude with the fact that capital rationing remains one of the main reason for not investing in renewable energy generation.

If a business manager is risk averse and if electricity price is their main input risk exposure, then investing in storage upfront is a sensible option. Exposure to electricity price is eliminated altogether and figure 8 shows that the sensitivity of the value of storage to LOCH is low. Investing in storage even if the LCOH is twice the value of the base case is still a much better option than doing nothing in scenario 2. Conversely, if we consider a manager with a risk taker profile, they may speculate that energy prices cannot increase forever without seriously hurting economies. It is therefore reasonable to consider that the exposure to risk is captured by scenario 2, i.e. the only risk is a short-term energy crisis. Assuming that a business has enough cash to shoulder the higher price during the crisis, it will benefit from not investing in storage.

Conclusion

Renewable energy investments have for long been regarded as difficult to justify because of their costs and intermittent nature. Often, environmental concerns and matters of energy security must be invoked to justify these investments and deploy subsidies or other support mechanisms. As electricity storage is only at an early adoption stage of its lifecycle, prices are high, meaning that few energy users will consider an investment in storage practical. In this paper, we have used a real options approach to reveal the importance of not thinking of different technologies as independent investment projects. This is because different technologies embed high complementary asset real option value. In the event of either an important decrease in the price of these technologies, or an increase in the volatility of future energy prices, or a continued decrease of FiTs, this complementary asset option value is such that it could reverse the logic of investment evaluation altogether. This is an important conclusion when considering the need to design sustainable energy systems for the future and the social cost of energy crises. The results indicate the necessity for more adaptable policy measures, wherein the policymaker must distinguish the reasons why a microgrid exports power, and whether these exports benefit the whole energy system. This is illustrated, for example, by the difference between autonomous versus collaborative microgrids. Improved FiTs at competitive prices are required to incentivise investments that result in microgrids exporting green electricity as a result of levelling out their orders to the utility grid. Alternatively, for autonomous microgrids, particularly those including storage, alternative measures like as subsidies or loans may be more successful than FiTs.

The objective of this paper is only to present a practical illustration of the complementarity mechanisms, and it leaves many questions unexplored. For example, storage is only considered as a short-term production levelling mechanism in this paper, and the impact of season or unusual weather patterns is not explored. Considering longer-term storage solutions is expensive, but it will reveal new ways of using renewable energy systems, i.e. new complementarities. Similarly, the idea of using non-renewable energy sources as back-up generation sources is not popular for environmental reasons but also because the low utilisation of these backup assets makes them expensive. However, by considering asset complementarity between renewable sources and back up generation, it becomes possible to define optimal storage and back up generation practices. All these questions are important directions for future research.

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