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Managing investor and consumer exposure to electricity market price risks through Feed-in Tariff design

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Abstract

Feed-in Tariffs (FiTs) incentivise the deployment of renewable energy technologies by subsidising remuneration and transferring market price risk from investors, through policymakers, to a counterparty. This counterparty is often the electricity consumer. Different FiT structures exist, with each transferring market price risk to varying degrees. Explicit consideration of policymaker/consumer risk burden has not been incorporated in FiT analyses to date. Using Stackelberg game theory and option pricing, we define FiT policies that efficiently divide market price risk, conditional on risk preferences and market conditions. We find that commonly employed flat-rate FiTs are optimal when policymaker risk aversion is extremely low whilst constant premium policies are optimal when investor risk aversion is extremely low. This suggests that if investors are considerably risk averse, the additional remuneration offered to incentivise deployment under a constant premium regime may be sub-optimal. Similarly, flat-rate FiTs are sub-optimal if policymakers are considerably risk averse. When both policymakers and investors are considerably risk averse, an intermediate division of risk is optimal. We find that investor preferences are more influential than those of the policymaker when degrees of risk aversion are of a similar magnitude. Efficient division of risk is of increasing importance as renewables comprise a greater share of total electricity cost. Different divisions of market price risk may thus be optimal at different stages of renewables deployment. Flexibility in FiT legislation may be required to accommodate this.

Keywords: Renewable Energy, Feed-in Tariff, Option Pricing, Renewable Support Schemes, Market Price Risk

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1. Introduction

The intermittent nature of many renewable energy sources combine with uncertain market prices to make renewable energy investment an inherently risky venture. Feed-in Tariffs (FiTs) guarantee a set payment per unit of electricity generated and thus limit investors' exposure to low market prices to a greater extent than alternate mechanisms (Burer and Wustenhagen, 2009; Fagiani et al., 2013; Haas et al., 2011; IEA and OECD, 2008; Ragwitz et al., 2007). Although theoretically less efficient than quantity-based schemes (Ringel, 2006), FiTs have become a preferred policy mechanism for many jurisdictions as the reduced exposure to market price risk has incentivised greater deployment of renewable technologies (Menanteau et al., 2003; Haas et al., 2011).

FiTs do not eliminate market price risk but rather transfer this risk to a counterparty. This counterparty bears the risk of additional policy cost if wholesale prices are less than the FiT guarantee. Often, a policymaker incurs this aggregate risk in the first instance, which is then transferred to electricity consumers through additional charges on consumption (Farrell and Lyons, 2014; Gross et al., 2010). Different FiT designs apportion this risk in different ways (Couture and Gagnon, 2010; Kim and Lee, 2012), with zero, partial or full transfer of market price risk possible (Farrell et al., 2013). Although the literature has acknowledged that appropriate risk transfer is central to successful renewables policy (Klessmann et al., 2013), the optimal division of risk has not been analysed. The literature to date has concentrated on accommodating investor attitudes to risk (Burer and Wustenhagen, 2009; Butler and Neuhoff, 2008; Kitzing, 2014; Falconett and Nagasaka, 2010; Dong, 2012; Menanteau et al., 2003; Ragwitz et al., 2007; Ringel, 2006). These analyses have discussed policy cost in terms of expected values but have not addressed policymaker/consumer preferences to cost uncertainty when deciding on a policy regime. These factors are of increasing importance in academic and policy debate as the magnitude of consumer costs are growing with deployment (Klessmann et al., 2013; Leepa and Unfried, 2013; Loreck et al., 2012). Market developments may also influence this importance. The proliferation of low-cost unconventional gas may have a depressing effect on fossil fuel prices (Energy Information Administration, 2012; Logan et al., 2013). This may potentially increase the relative cost of renewables (Rauch, 2013) and add to existing risks of an increase in policy cost.

To correctly identify the optimal degree of policy intervention in renewables deployment, a characterisation of investors' and policymaker's/consumers' attitude to market, regulatory and policy risks, and their reactions in different contexts, is required (Ekins, 2004; Gross et al., 2010).

Abbreviations: CARA: Constant Absolute Risk Aversion; CE: Certainty Equivalent; CfD: Contract for Difference; CRRA: Constant Relative Risk Aversion; EMV: Expected Money Value; FiT: Feed-in Tariff; IEA: International Energy Agency; MW: Megawatt; OECD: Organisation for Economic Cooperation and Development; O & M: Operations & Maintenance; REFIT: Renewable Energy Feed-in Tariff; ROC: Renewables Obligation Certificate; SEM: Single Electricity Market; VWAP: Volume-Weighted Average Price

This paper addresses this gap, contributing a framework to characterise both investor and policy-maker/consumer exposure to risk, where one can identify the market conditions and attitudes under which a given degree of policy intervention is optimal. Indeed, optimal division of risk between investors and policymakers/consumers is analogous to the division of risk central to the design of insurance contracts (Raviv, 1979). This paper presents a framework to divide risk in a similar way and is structured as follows. The following section will give a literature review. Section 3 will outline the economic problem and methodology employed. Section 4 presents the results whilst Section 5 offers a sensitivity analysis with respect to market parameters and investor/policymaker attitudes to risk. Finally, Section 6 offers a discussion and conclusion.

2. Literature Review and Motivation

Identifying the optimal division of market price risk brings together literature focussing on investment incentives and consumer policy cost. Much analysis from an investor's perspective has compared FiTs with alternate mechanisms (Dong, 2012; Fagiani et al., 2013; Menanteau et al., 2003; Ragwitz et al., 2007; Ringel, 2006). FiTs have led to greater deployment than alternatives as investor exposure to market price risk is lower (Burer and Wustenhagen, 2009; Butler and Neuhoff, 2008; Kitzing, 2014; Falconett and Nagasaka, 2010). Indeed, exposure and attitude to risk is a key determinant in the superior effectiveness of FiT regimes. Comparing FiTs to quantity-based policies, Fagiani et al. (2013), Kitzing et al. (2012) and Kitzing (2014) have emphasised the importance of incorporating market price risk when deciding on a particular policy design, whilst Dinica (2006) state that the relationship between risk and profitability is key to encouraging investment.

Fewer studies have focussed on how different FiT structures affect investment. Couture and Gagnon (2010) offer a descriptive comparison of risk exposure under different FiT designs. Kim and Lee (2012) have analysed FiT payout structures to incentivise Solar PV deployment. Kim and Lee (2012) incorporate network effects and the propensity to adopt household-based solar PV. However, they do not evaluate how different attitudes to market price risk may affect results. Doherty and O'Malley (2011) also focus on investors when analysing the efficiency of Ireland's FiT design. Although they suggest that the current Irish FiT over-remunerates investors, they do not compare FiT choice amongst efficiently specified options, nor do they consider consumer and investor attitudes to market price risk. Farrell et al. (2013) provide a model with which different FiT regimes may be efficiently defined using option pricing theory. For each design, cost and remuneration are equal in expectation. However, the balance of certain/uncertain policy cost and investor remuneration varies between policy options. Farrell et al. (2013) discuss the concept of risk-sharing when choosing between designs. They do not quantify these preferences nor do they consider the quantified sensitivity of FiT choice to changes in these preferences.

Although managing investor risk exposure has been found to be of great importance for optimal energy policy, less attention has been given to managing policymaker/consumer risk exposure. However, a body of literature exists to analyse trends in policymaker/consumer cost. Leepa and Unfried (2013) discuss the impacts of overdeployment and how this may result in excessive consumer cost. Low market prices presents a similar risk of excessive consumer cost. Indeed, a greater penetration of renewables coupled with lower than expected fossil fuel cost has resulted in greater subsidies in recent years (Bryant, 2013; Chawla and Pollitt, 2013; DW, 2013; Farrell and Lyons, 2014; Loreck et al., 2012) with potential for this trend to continue (Batlle, 2011; Chawla and Pollitt, 2013; Devitt and Malaguzzi Valeri, 2011; Fagiani et al., 2013; Klessmann et al., 2013; Leepa and Unfried, 2013; Loreck et al., 2012). One can see that increasing policy cost is a consistent trend, with uncertainty regarding the extent of future policy cost (Devitt and Malaguzzi Valeri, 2011; Klessmann et al., 2013). Given that the setting of a FiT policy is carried out in a prospective manner, where future costs are uncertain, the incorporation of consumer burden and attitudes to risk of excessive policy cost is an important consideration.

Thus, it is important to correctly manage both investor and policymaker exposure to market price risk when designing renewables policy. Discussed in Section 1, such management involves balancing a trade-off: removing one degree of market price risk from the investor requires the policymaker to bear an additional degree of risk. Whilst analyses such as that of Kitzing (2014) and Leepa and Unfried (2013) have considered policy cost under different mechanisms, identifying the optimal point in this trade-off and efficiently managing policymaker exposure to an unexpected increase in future policy cost has not been considered. Such efficient division is quite common in other contexts. Raviv (1979) show that an optimal insurance contract may be designed by first identifying the insured's optimal level of coverage as a function of the insurance premium and then identifying the optimal premium from the insurer's perspective. Mahul (2001) apply a similar framework to identify how weather-dependent production may insure against climate risks, whilst Ma and McGuire (1997) model the design of optimal health insurance contracts.

With regard to FiT policy, analyses to date have compared broad policy specifications (e.g. fixed premium vs. fixed price) rather than a detailed division of market price risk. Such policy structures may not allow for the optimal division of risk to be identified. However, Farrell et al. (2013) have discussed how intermediate divisions of market price risk may be specified. Applying such a modelling framework allows for the optimal point illustrated in this trade-off to be identified.

3. Materials and Methods

FiTs transfer risk from investors, through policymakers, to consumers. To aid the discussion that follows, we refer to policymaker burden alone. However, this may be interpreted as a collective term for the total burden incurred by all consumers. The methodology of this paper comprises

three primary steps. First, we model electricity market prices. Second, we specify efficient FiT specifications which allow for investor remuneration/policy cost to be identified. Third, these cost/remuneration calculations are used alongside a model of risk averse investment to determine an optimal FiT design conditional on risk preferences. This methodology is applied to an Irish case study with data obtained from the literature. These steps will now be outlined in turn.

3.1. Market Prices

The market price, S_t , received by the renewable investor varies by jurisdiction. For the purpose of this analysis, we choose an Irish case study and thus consider annual Volume Weighted Average Prices (VWAP) Farrell et al. (2013). This is the annual average electricity price weighted by the volume of electricity generated through renewable sources and is used in certain jurisdictions such as Ireland to calculate wind remuneration (Doherty and O'Malley, 2011; Farrell et al., 2013). Much literature to date has modelled annual market price processes using a Geometric Brownian (GBM) (e.g. Yang and Blyth, 2007; Heydari et al., 2012; Zhu, 2012) and we follow this precedent. Following Farrell et al. (2013), Equations (1) and (2) show that changes in the Q of renewables installed affect the rate of growth in VWAP. In this way, any changes in prices due to the level of deployment are endogenous to the assumed price process and thus the investment decision. VWAPs are modeled this way because the 'merit order effect' of certain renewables with no marginal cost (e.g. wind, wave solar; Sensfuß et al., 2008) will result in lower rates of market price growth as the quantity Q of installed capacity increases.

$$dS = \mu(Q)Sdt + \sigma Sd\omega, \quad (1)$$

where

$$\mu(Q) = \bar{\mu} + \eta e^{-\kappa Q}, \quad (2)$$

and $d\omega$ represents the increment of the Wiener process.

3.2. Feed-in Tariff Prices

Once market prices are specified, we must specify efficient feed-in tariff prices. These are derived using the methodology proposed by Farrell et al. (2013). Illustrated in Figure 1, Different FiT designs transfer market price risk in different ways. Potential designs include a constant premium, where investors receive the market price and a constant premium during each trading period; a price floor with market upside shared between investors and policymakers; or a cap & floor policy.

A cap & floor places upper and lower bounds on the market price received by investors, whilst a shared upside offers investors a guaranteed price floor and a share of all market upside. A constant premium offers investors the market price and a constant premium at all times of generation. Farrell et al. (2013) show how each of these FiTs may be efficiently specified using option pricing

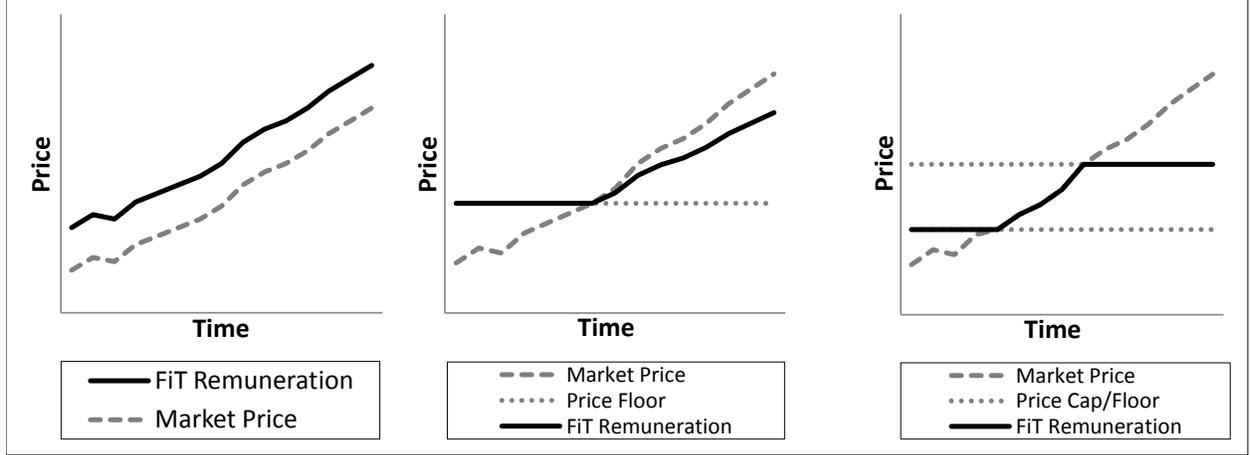


Figure 1: Payment structures: (left) constant premium, (middle) shared upside, (right) cap & floor.

theory. Certain elements of remuneration (i.e. caps or floors) are defined such that the expected value of uncertain market remuneration is taken into account. As such, a price floor would be lower than if no market upside were offered to investors and thus total remuneration (i.e. price floor remuneration + market upside) as opposed to the price floor alone, is sufficient to incentivise investment. This specification results in an inverse relationship between the efficient price floor and the degree of market ‘upside’ offered to investors. Should no market ‘upside’ be shared with investors, efficient price floors are highest, with both shared upside and cap & floor policies converging on a flat-rate price for investors. As a greater share of market upside is offered to investors, the efficient price floor falls to take into account of the value of the market upside. This continues until all market ‘upside’ is available to investors and both shared upside and cap & floor policies converge on a price floor regime. Policymakers incur a subsidisation cost for every trading period when market prices are less than pre-specified price floors and receive a benefit if they exceed a price cap. For a shared upside regime, policymakers receive a predefined share of the market upside in excess of the price floor. The procedure of efficient FiT specification developed by Farrell et al. (2013) is adopted for this study and will now be summarised.

3.2.1. Constant Premium

For a constant premium tariff, the discounted price received by the investor during time t (P_t) is the discounted value of the premium, X , added to the discounted value of market remuneration:

$$P_t = e^{-rt}(X + S_t), \quad (3)$$

which has a expected value

$$E[P_t] = Xe^{-rt} + S_0e^{(\mu-r)t}. \quad (4)$$

The cost for the policymaker, at time t , is constant at X .

3.2.2. Shared Upside

The expected value of remuneration under a shared upside policy comprises two constituent elements; a minimum price guarantee and a portion of market upside. Specifying the expected value of remuneration under this policy type must incorporate the expected value of both elements. This FiT structure resembles a European put option, where the investor has the right, but not the obligation to sell at time t at a given price (i.e., price floor K), but may also sell at the market price S_t should it exceed this floor. Farrell et al. (2013) augment option pricing theory to value P_t under a shared upside policy, with the discounted price at time t denoted as:

$$P_t = e^{-rt}(K + \theta(\max(S_t - K, 0))), \quad (5)$$

which has an expected value

$$E[P_t] = Ke^{-rt}(1 - \theta N(d_2)) + \theta S_0 e^{(\mu-r)t} N(d_1), \quad (6)$$

where $N(\cdot)$ represents the cumulative distribution function of the standard normal distribution while

$$d_1 = \frac{\ln(\frac{S_0}{K}) + (\mu + \frac{\sigma^2}{2})t}{\sigma\sqrt{t}}, \quad (7)$$

$$d_2 = \frac{\ln(\frac{S_0}{K}) + (\mu - \frac{\sigma^2}{2})t}{\sigma\sqrt{t}}. \quad (8)$$

Discounted policy cost under a shared upside regime is

$$F_t = e^{-rt}(\max(0, K - S_t) - (1 - \theta) \max(0, S_t - K)). \quad (9)$$

whose expected value may also be calculated using option pricing theory, as follows:

$$E[F_t] = Ke^{-rt} - S_0 e^{(\mu-r)t} + \theta \left(S_0 e^{(\mu-r)t} N(d_1) - Ke^{-rt} N(d_2) \right). \quad (10)$$

3.2.3. Cap & Floor

A cap & floor policy is also like a put option, where investors have the right to sell at a price floor, but may sell at the market price should it exceed the floor. However, should the price exceed the cap, remuneration is equal to the cap and no more. The price P_t under this policy design is:

$$P_t = e^{-rt}(K + \max(S_t - K, 0) - \max(S_t - \bar{S}, 0)) \quad (11)$$

whose expected value may also, as Farrell et al. (2013) show, be calculated using option pricing theory:

$$E[P_t] = Ke^{-rt} \left(1 - N(d_2)\right) + S_0 e^{(\mu-r)t} \left(N(d_1) - N(d_3)\right) + \bar{S} e^{-rt} N(d_4) \quad (12)$$

where d_1 and d_2 are as previously defined and

$$d_3 = \frac{\ln\left(\frac{S_0}{\bar{S}}\right) + \left(\mu + \frac{\sigma^2}{2}\right)t}{\sigma\sqrt{t}}, \quad (13)$$

$$d_4 = \frac{\ln\left(\frac{S_0}{\bar{S}}\right) + \left(\mu - \frac{\sigma^2}{2}\right)t}{\sigma\sqrt{t}}. \quad (14)$$

For a cap & floor policy, the cost of the FiT at time t is

$$F_t = \max(0, K - S_t) - \max(0, S_t - \bar{S}). \quad (15)$$

which has an expected value

$$E[F_t] = Ke^{-rt}(1 - N(d_2)) - S_0 e^{(\mu-r)t}(1 - N(d_1)) - S_0 e^{(\mu-r)t} N(d_3) + \bar{S} e^{-rt} N(d_4). \quad (16)$$

3.3. Model of Risk-averse Investment

The procedure of modelling renewable energy investment follows the Stackelberg leader game of Farrell et al. (2013). Industry investors decide on a Q level of investment in a given renewable energy technology, conditional on the FiT price offered by the policymaker. In this Stackelberg game, the leader (policymaker) chooses their strategy (FiT price) first with followers (investors) implementing their strategy (investment) conditional on the leader's choice (Chang et al., 2013; Fudenberg and Tirole, 1991). Under this framework investors are modelled as a whole and hence as a single player in the Stackelberg game. The policymaker anticipates the investors' strategic response and chooses the FiT price that results in deployment of the desired quantity of renewable generation. It is assumed that a policymaker wishes to incentivise the deployment of Q_I units, which operate during T discrete time periods in a time horizon $[1, T]$, indexed by t .

FiTs vary according to the degree of certain and uncertain payments in overall remuneration. For investors, a greater proportion of certain payments in overall remuneration reduces market price risk. This is achieved by offering the investor a higher price floor and thus a lower proportion of market upside/lower cap. However, offering a policy of greater revenue certainty for investors requires a greater degree of market price uncertainty to be borne by the policymaker, as a higher floor exposes the policymaker to a greater cost should market prices be low. A FiT must be chosen such the balance of uncertain and certain remuneration incentivises investors to install

Q_I units whilst allowing policymakers to minimise the welfare loss associated with policy cost and exposure to market price risk. Incorporating aversion to market price risk when evaluating cost/remuneration may be incorporated into the decision-making process through the use of a utility function. Under the axioms of a von Neumann-Morgenstern utility function a decision-maker is risk-averse, rational and will act to maximise expected utility (von Neumann and Morgenstern, 1947). A number of utility function specifications exist, each of which may be potentially chosen. A Constant Absolute Risk Aversion (CARA) utility function has a constant degree of risk aversion regardless of the absolute level of the outcome variable being analysed (e.g. wealth, consumption, cost). A Constant Relative Risk Aversion (CRRA) utility function is similar however it has a scaling factor which calibrates the agent's degree of risk aversion according to a pre-existing level of the outcome variable (Arrow, 1971; Meyer and Meyer, 2005). For policymakers, the outcome variable is electricity cost. The literature to date suggests an increasing concern surrounding FiT costs as they comprise a greater share of total electricity cost (Batlle, 2011; Leepa and Unfried, 2013; Loreck et al., 2012). As such, policymakers may become more averse to FiT cost uncertainties as they comprise a greater proportion of electricity cost. A CRRA functional form captures this relationship. For investors, wealth is the outcome variable. Much of the literature to date has employed a CRRA functional form when analysing investment in energy markets and large scale investments (Chronopoulos et al., 2014; Cotter and Hanly, 2012). Given this precedent and ability to calibrate CRRA utility functions to a realistic degree of risk aversion, a CRRA functional form is chosen for this analysis.

3.3.1. Investor Utility

Under a CRRA utility function, utility for the investor and policymaker is comprised of a scaling parameter and profit/cost of deployment. Generally, pre-existing wealth is used for this scaling parameter. For policymakers and investors in renewable energy, pre-existing wealth may be difficult to define. To ensure that our results are calibrated to realistic degree of risk aversion, we choose the scaling parameter such that the resulting rates of risk aversion are deemed reasonable given the literature. Such flexibility is a further benefit of the CRRA utility function over less flexible forms such as the CARA functional form.

We model investors in a given market together as one entity (Farrell et al., 2013). The investors' utility, under scenario l , is modelled using a power law utility function with risk aversion parameter $\alpha \geq 0$:

$$U_l^{Inv} = \begin{cases} \left(\frac{1}{1-\alpha}\right)(W_l^{Inv})^{1-\alpha} & \text{if } \alpha \neq 1 \\ \ln(W_l^{Inv}) & \text{if } \alpha = 1 \end{cases} \quad (17)$$

The investors' outcome variable, wealth (W_l^{Inv}) under scenario l , is comprised of the scaling

parameter w_{pre}^{Inv} and profit from investment, $\Pi_l(Q)$. This profit is uncertain and subject to fluctuations in market prices and thus varies from scenario to scenario. The amount of uncertainty differs depending on the policy enacted. The investors' profit is also dependent on Q , the number of installed units of renewable energy technology. The Investors' wealth under scenario l is

$$W_l^{Inv} = w_{pre}^{Inv} + \Pi_l(Q). \quad (18)$$

Total industry profit $\Pi_l(Q)$, received during operation from time $t = 1$ to T , is defined according to Equation (19).

$$\Pi_l(Q) = \sum_t [P_t(Q)G(Q)] - C(Q), \quad (19)$$

where P_t is the discounted price received during time t , which may be either the market price S_t^1 or the guaranteed price offered by a given FiT regime. Guaranteed elements of investor remuneration may be either a price floor (K) a cap (\bar{S}) or a share of market upside (θ), depending on the FiT design chosen.

For the installation of Q units, $C(Q)$ is the sum of industry-level capital (A) and operating (O) costs (including any required return to personnel, capital, etc.), discounted according to a discount rate r :

$$C(Q) = AQ + \sum_{t=1}^T e^{-rt} OQ \quad (20)$$

The amount of electricity generated from renewable sources during time t is $G(Q)$. As with Farrell et al. (2013) this function is calculated according to the following equation:

$$G(Q) = b(Q)uvh \quad (21)$$

where v is operational availability net of maintenance and other such outages, u is the capacity factor for initial units and h is the number of hours per time period t . The function b is given by

$$b(Q) = Q_{max}(1 - e^{-\gamma Q}) \quad (22)$$

where Q_{max} is the maximum potential Q , whilst γ is a parameter controlling the rate of change. Equation (22) models capacity by incorporating changes in effective capacity/availability as Q changes².

The investors' objective is to maximise expected utility by choosing a Q level of output:

¹While P_t and S_t are both determined stochastically and hence vary from scenario to scenario, for ease of presentation, the subscript l is ignored for these two variables.

²See Farrell et al. (2013) for further discussion on Equations (21) and (22).

$$\max_Q U^{Inv} = \max_Q E[U_l^{Inv}], \quad (23)$$

$$\max_Q U^{Inv} = \max_Q \int_0^\infty \left(\frac{1}{1-\alpha} \right) \left(W_l^{Inv}(Q) \right)^{1-\alpha} Pr(l) dl, \quad (24)$$

where $Pr(l)$ is the probability associated with scenario l . Assuming concavity, the investors' utility function is maximised when

$$\frac{\partial U^{Inv}}{\partial Q} = 0. \quad (25)$$

3.3.2. Policymaker Utility

In a similar manner to above, the policymaker's utility, under scenario l , is modelled using a power law utility function with risk aversion parameter $\beta \geq 0$:

$$U_l^{policy} = \begin{cases} \left(\frac{1}{1-\beta} \right) \left(W_l^{policy} \right)^{1-\beta} & \text{if } \beta \neq 1 \\ \ln(W_l^{policy}) & \text{if } \beta = 1 \end{cases} \quad (26)$$

The policymaker's outcome variable is total electricity cost, W_l^{policy} under scenario l . This is comprised of the scaling parameter, w_{pre}^{policy} , less the cost of the chosen FiT design. This is calculated as follows

$$W_l^{policy} = w_{pre}^{policy} - F_l(Q). \quad (27)$$

As with the investors' profits, the cost $F_l(Q)$ is subject to fluctuations in market prices and thus varies from scenario to scenario whilst also depending on the amount of units of renewable energy technology installed. This cost is the sum of the difference between the price that the investors receives P_t and the market price S_t :

$$F_l = \sum_t F_t = \sum_t P_t(Q) - S_t(Q) \quad (28)$$

The policymaker's goal is to choose the FiT design that maximises their expected utility whilst ensuring that investors choose Q_I units of renewable energy technology as follows:

$$\max U^{policy} = \max E[U_l^{policy}], \quad (29)$$

$$\max U^{policy} = \max \int_0^\infty \left(\frac{1}{1-\beta} \right) \left(W_l^{policy} \right)^{1-\beta} Pr(l) dl, \quad (30)$$

subject to

$$Q = Q_I, \quad (31)$$

$$\frac{\partial U^{Inv}}{\partial Q} = 0. \quad (32)$$

3.3.3. Solving this problem

Including the investors' optimality condition as a constraint in the policymaker's problem ensures that the policymaker chooses the FiT design that will allow the investors to maximise their profits with Q_I units installed. The policymaker's problem is set up as a maximisation problem to aid computation. As pre-existing electricity cost is held constant, it is equivalent to minimising the FiT cost. The CRRA specification allows aversion to FiT cost to be considered relative to total electricity cost.

In the numerical examples presented in Sections 4 and 5, the derivative in Equation (32) is approximated using finite differences as follows

$$\frac{\partial U^{Inv}}{\partial Q} \approx \frac{U(Q) - U(Q - \Delta Q)}{\Delta Q} = 0, \quad (33)$$

where ΔQ is small while the market price (S_t) is simulated using Monte-Carlo simulation. Thus, both policymaker and investor wealth, and hence expected utility, are also calculated via Monte-Carlo simulation. 100,000 simulation iterations are run for this procedure.

3.3.4. Interpreting utility

Utility may be interpreted as the derived utility value or the 'Certainty Equivalent' (CE). The CE is calculated as the inverse of the derived utility value and is the certain amount of remuneration/policy cost that yields the same utility as an uncertain alternative (Hardaker et al., 2004). The Expected Money Value (EMV; the expected value of remuneration) of an uncertain level of remuneration may be higher than its CE, reflecting aversion to risk. The CE of a return falls as remuneration becomes more uncertain, whilst the CE of a cost increases with uncertainty.

3.4. Investment data

This analysis may be carried out for any renewable technology and wind turbine deployment in Ireland is chosen for this analysis. A stylised case study following Farrell et al. (2013) is considered, with parameters outlined in Table 1. We assume that the cost parameters of Table 1 include any ordinary profits and additional remuneration required to cover non-market price related risks. This allows us to focus on any additional remuneration required to compensate for market price risk. It is assumed that a wind turbine is operational for 20 years, with FiT remuneration available during all 20 years of operation.

W_l^{policy} is calculated as the risk aversion scaling parameter w_{pre}^{policy} less the expected cost of the FiT policy, $F_l(Q)$. w_{pre}^{policy} is chosen such that the observed degrees of risk aversion represent those

expected by the literature. Hirst (2002) estimate that hedging wholesale market price risk to provide a fixed cost for consumers adds 5-10% onto electricity cost. Zhang and Wang (2009) analyse a number of contracts to provide a hedge against wholesale market fluctuations for consumers, finding that contract prices may range anywhere from 0.38% to 23% of the electricity price, depending on the portion of the load that is hedged. For fixed price tariffs with a high fixed price, they find that hedge contracts may range from 0.38-4.12%. This literature analysing electricity price hedging focuses on hedging all market price risk, not just the FiT cost portion. Given that FiT costs comprise a smaller proportion of electricity cost than the total electricity cost that is analysed in these papers, we take this lower range as being a more representative range of hedge values considered. We chose this range for our baseline analysis but test sensitivity to alternate ranges in Section 5.

Similarly, w_{pre}^{inv} is chosen such that investors' risk aversion is of a range considered realistic. Hern et al. (2013) survey wind investors in the UK and find that switching from a Renewable Obligation Certificate (ROC) scheme to a FiT through Contracts for Difference (CfD), in essence a switch from incurring market price risk to incurring no market price risk, results in a 20% reduction in the expected rate of profitability for onshore wind. This gives a rough benchmark as to the premium required for incurring market price risk in wind investment. Although providing a suitable benchmark, the degree of risk presented to UK investors is slightly different to that in Ireland and actual premiums in an Irish context may deviate from this benchmark. Indeed, premiums may vary for each investor. Nevertheless, in the absence of further information, the findings of Hern et al. (2013) provide a useful calibration point, where baseline findings of 'high', 'expected' or 'low' levels of investor risk aversion may be interpreted relative to this benchmark.

Risk aversion parameters generally range from 0 (risk neutral) to 4 (extremely risk-averse) for CRRA utility functions (Anderson and Dillon, 1992). Arrow (1965) assumes that risk aversion 'hovers about 1'. As such, w_{pre}^{inv} is assumed to be €18.98bn such that a change from a policy of constant premium to fixed price requires a c.20% premium on investment when the risk aversion parameter is 1. If one believes that alternate levels of risk aversion are more appropriate, a wide range of risk aversion parameters are modelled to capture the optimal investment. We also carry out a sensitivity analysis with respect to the w_{pre}^{inv} parameter to capture further degrees of risk aversion. Section 4.1 discusses the implications of different risk aversion parameters to aid interpretation should the reader prefer alternate levels of risk aversion.

4. Results and Discussion

4.1. Risk Aversion

First we present quantified representations of risk aversion to aid interpretation of policy choice results. Table 2 shows the CE of 20-year discounted policy cost under different levels of risk aversion (β) for a shared upside policy when $\theta = 1$. When $\beta = 0$, the CE is the same as the

Table 1: Baseline Simulation parameters

Parameter	Value
Capital Cost (Wind, per MW)	€1.76m ^a
Annual Operations & Maintenance Cost	2% of capital cost ^a
Irish Single Electricity Market (SEM) Installation target (Q_I)	4,630 MW ^b
Capacity Factor (u)	0.35 ^a
Availability (v)	0.95 ^a
Maximum Q (Q_{max})	16 GW ^c
γ	$(6.75 \times 10^{-5})^b$
Generation during t (G_t)	12,501,319 ^e
Long-run electricity Price Growth ($\bar{\mu}$)	0.0155 ^a
η	0.01 ^e
κ	0.001 ^d
Electricity Price Volatility (σ)	0.13 ^a
Initial VWAP (S_0)	€52.41 ^a
Discount Rate (r)	0.06
w_{pre}^{inv}	€18.98bn ^e
w_{pre}^{policy}	€38.36bn ^e

Source: ^a calibrated to Doherty and O'Malley (2011); ^b calibrated to Mc Garrigle et al. (2013); ^c SEAI (2011); ^d calibrated to IWEA (2011); ^e own calculation

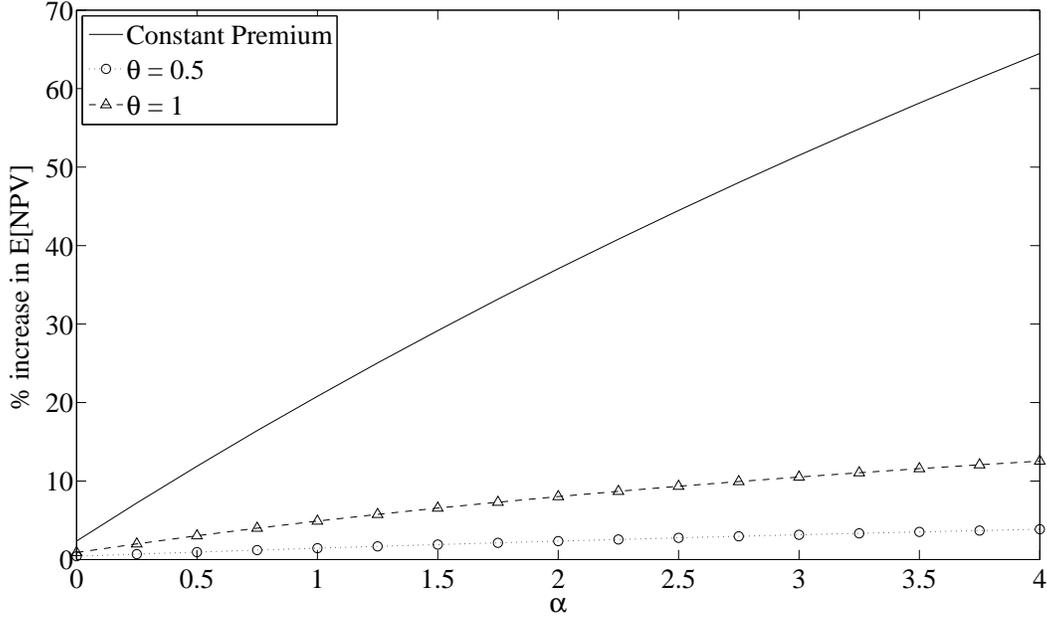
expected value of remuneration. One can see that as the risk aversion parameter β grows, the CE grows also as the policymaker is willing to incur a greater certain policy cost in order to forego a given level of cost uncertainty. When a β parameter of 1 is in place, the policymaker is willing to take a certain cost that is 1.36% higher to forego the possibility of incurring extremely high policy cost. One can see that this threshold increases as the policymaker's level of risk aversion grows, with a β value of 4 implying that a policymaker is indifferent between incurring the uncertain policy cost and a certain payment that is 5.527% greater than the expected value (i.e. $\beta = 0$).

Table 2: Certainty equivalent of 20-year discounted policy cost by level of risk aversion (β)

β	0	1	2	3	4
Certainty Equivalent	3.252bn	3.296bn	3.341bn	3.386bn	3.432bn
Increase relative to $\beta = 0$	0	1.367%	2.745%	4.132%	5.527%

To understand investor risk aversion, Figure 2 compares the change in EMV required by an investor under different α risk aversion parameters as a result of switching from a fixed price policy ($\theta = 0$) to varying degrees of shared upside and a constant premium. One can see that when $\alpha = 1$, EMV must be c.20% greater for investment under a constant premium. This corresponds to the added remuneration quoted by Hern et al. (2013) and thus provides a suitable benchmark

Figure 2: Quantification of Investor Risk Aversion



rate of investor risk aversion. One can see that the risk-sharing properties of the shared upside policies result in a much lower additional level of remuneration than the constant premium regime. However, EMV is still c.5-10% greater than when $\theta = 0$. These rates of risk aversion are given greatest attention in this analysis. Section 5 presents results relative to alternate ranges of risk aversion.

4.2. Optimal policy choice

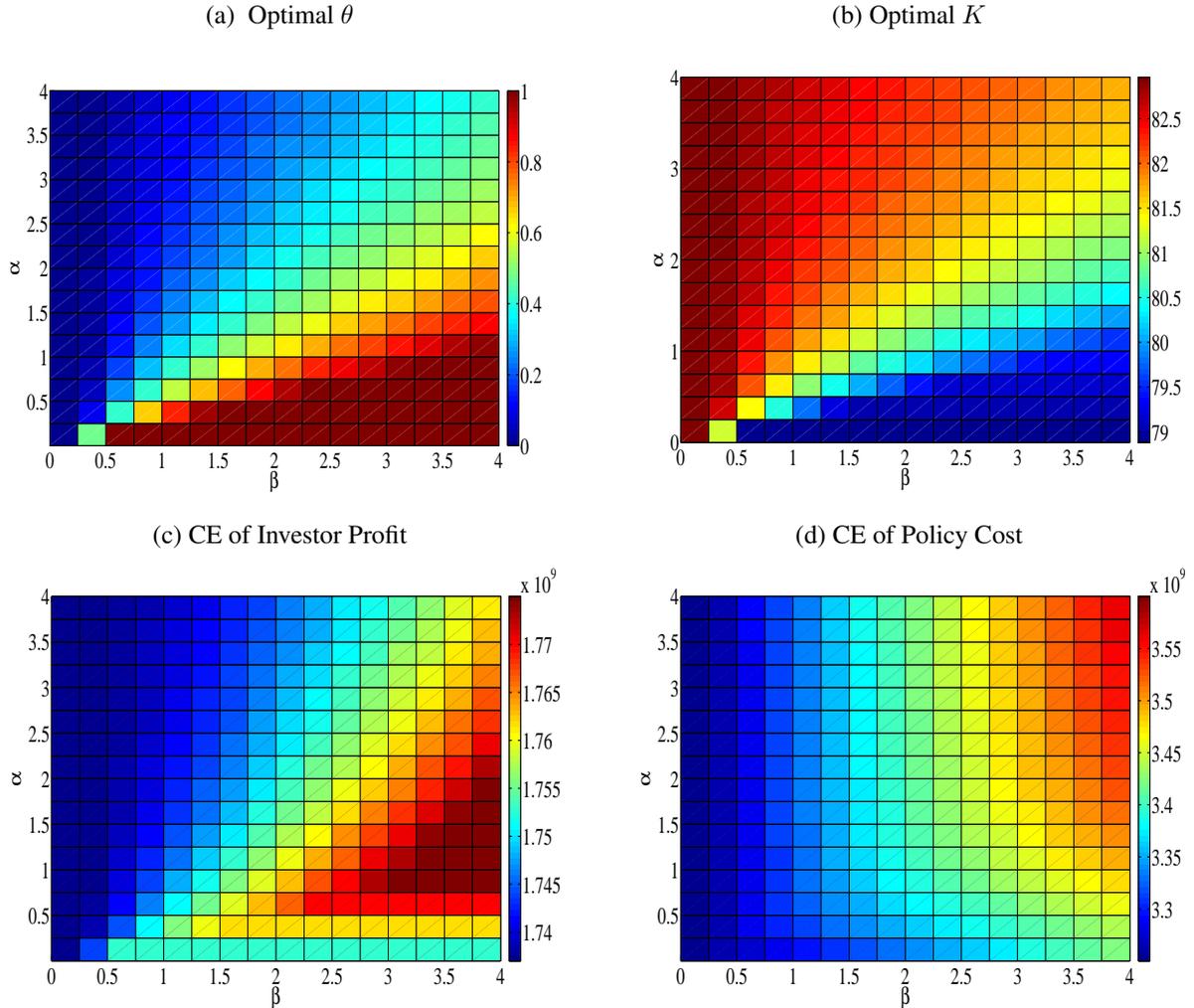
We identify optimal levels of market price risk division both within and between policy types. This is first carried out for the discussed baseline scenario, followed by a sensitivity analysis with respect to the calibrated degree of risk aversion and assumed market price parameters. Quantifying such sensitivity gives insight into what FiT policy designs may be optimal when parameters differ from our baseline assumptions. The results of Table 2 and Figure 2 may be used to aid interpretation of risk aversion parameters in the baseline discussion that follows.

4.2.1. Optimal shared upside policy

Figures 3(a) and 3(b) show the optimal price floor (denoted K) and corresponding share of market upside (θ) for each α and β combination. We find an inverse relationship, predicted by Farrell et al. (2013), where a larger share of market upside (θ) results in a smaller price floor (K).

Figure 3 shows that the optimal division of market price risk is primarily a function of the relative balance of risk aversion. If investors have very low level of risk aversion, (≤ 0.25) and

Figure 3: Optimal Shared Upside Specifications



Note: Figure displays optimal θ (share of market upside going to investor), K (price floor) for a shared upside regime simulated using market parameters outlined in Table 1. Figure 3(c) and (d) show the Certainty Equivalent of investor profit and policy cost under each scenario.

policymakers are extremely risk averse, it is optimal for investors to bear the greatest share of market price risk through a price floor regime. Similarly, if policymakers have a low level of risk aversion (≤ 0.25), a fixed price regime is optimal. Figure 3(a) shows that intermediate policies are optimal when both investors and policymakers have similar degrees of risk aversion. We see that should investors and policymakers have an equal degree of risk aversion, a lower θ value is optimal, indicating that investors are more dominant. Indeed, it is only when investors have an extremely low level of risk aversion (≤ 1) that a price floor policy is optimal. For this to occur, the magnitude of policymaker risk aversion must be in the region of three times greater than investors' risk aversion.

Figures 3(c) and 3(d) show the difference in CE for investor profit and policy cost (less pre-

existing wealth) to give insight into the additional remuneration required for the risk borne by each party under each scenario. Interestingly, we see different patterns for investor and policymaker risk.

In Figure 3(c) we see that additional investor remuneration to account for price risk is greatest when policymaker risk aversion is high (about 4) and investor risk aversion is about 1. In such circumstances, the policymaker's preferences dominate those of the investor, and a θ close to 1 prevails. This requires investors to incur almost all market price risk. As the optimal θ is higher than alternate scenarios where α is high, investors require a greater degree of additional remuneration to bear this additional risk. Under this circumstance the policymaker is willing to incur a considerable additional certain cost to ensure that they minimise their exposure to market price risk. However, this diagram shows that offering such an additional level of remuneration is only optimal when policymaker's level of risk aversion is much greater than investors. The disutility associated with an increase in additional investor payments shown in Figure 3(c) combines with the greater disutility associated with increased investor risk aversion to give the pattern of Figure 3(d). Figure 3(d) shows that policymaker disutility grows with both investor and policymaker risk aversion.

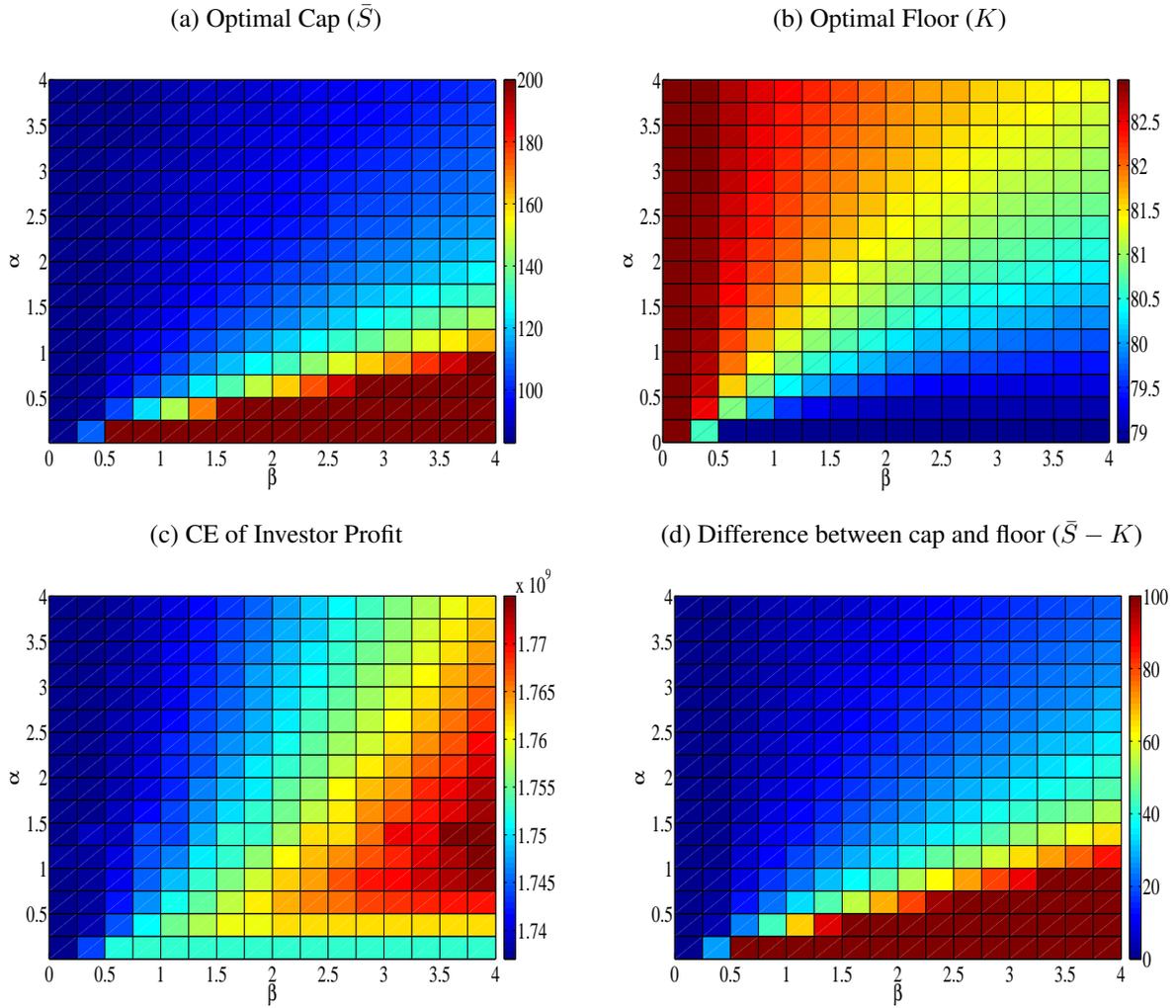
4.2.2. *Optimal cap & floor policy*

Figure 4(a) and Figure 4(b) show efficient cap (\bar{S}) and floor (K) policies, analogous to the results of Figure 3. To aid interpretation of the degree of market price variability that each party is exposed to under each policy, the difference between the cap and floor for each scenario is displayed in Figure 4(d). Analysing these results indicates that the pattern of optimality for cap and floor policies follows a similar trend to that of the shared upside policy.

However, one difference may be observed. For each risk aversion scenario that involves investors receiving market upside, cap & floor policies require a slightly lower efficient price floor. This is due to differences in the pattern of risk sharing between policies and the attitudes of each party to such differences. A shared upside policy offers a portion of all market prices in excess of an efficient floor, whilst a cap & floor policy offers all market prices, in their entirety, in excess of the floor and as far as a certain threshold (cap). Each market price has a probability of occurrence, with lower prices having a greater probability than higher prices. As a result of these differences, cap & floor policies have a greater emphasis on prices that are more likely to occur. This improves the expected value of market remuneration for a cap & floor regime relative to a shared upside regime and the required efficient price floor is slightly lower.

These effects are most evident when one examines Figure 4(c) where the investor certainty equivalent follows a similar trend to the shared upside policy, but is of a modestly lesser amount. This difference reflects the Investors' aversion to greater reliance on market remuneration that is

Figure 4: Optimal Cap & Floor Specifications



Note: Figure displays optimal \bar{S} (price cap), K (price floor) for a cap & floor regime simulated using market parameters outlined in Table 1. The \bar{S} value of '200' denotes all values greater than or equal to 200. Figure 3(c) shows the Certainty Equivalent of investor profit under each scenario. Figure 3(d) shows the difference between the cap and floor under each regime, with '100' denoting all values greater than or equal to 100.

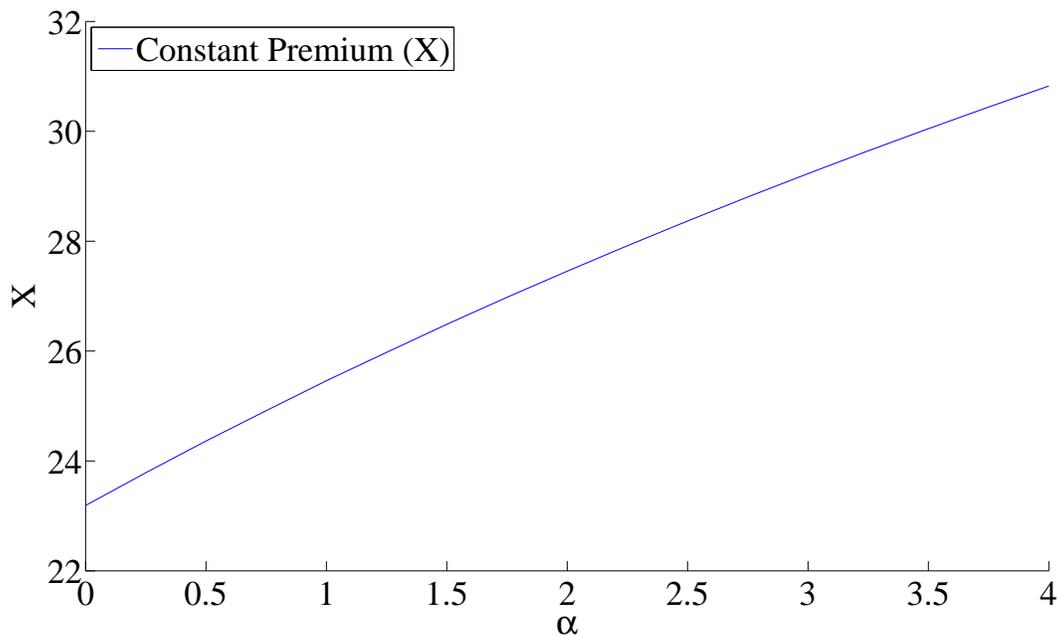
more uncertain. The slightly lower price floor for a cap & floor regime reflects the small difference in market price risk that must be borne relative to a shared upside policy.

The purpose of this model is to compare efficiently specified FiTs and does not capture FiT misspecification. However, Farrell et al. (2013) illustrate a further benefit of cap & floor regimes in this regard. Greater protection against FiT misspecification may be offered by a cap and floor regime, where policymaker's are protected against offering over-remuneration should market prices exceed the cap to a degree that is greater than expected. This characteristic may affect the choice between policy options, alongside the differences outlined when FiTs are efficiently specified.

4.2.3. Optimal Constant Premium Policy

Optimal constant premium policies are insensitive to the degree of policymaker risk aversion as the policymaker does not incur any market price risk. Differences in FiT prices offered are thus entirely determined by the risk premium required by investors. Figure 4.2.3 shows that the pattern of optimality follows an increasing and concave trend. For each additional degree of investor risk aversion, a considerable increase in remuneration is required. For this baseline policy scenario, the required premium grows from €23.1/MWh when $\alpha = 0$, to to €25.5/MWh when $\alpha = 1$. This rises to €30.8/MWh when α rises to 4. This is due to the fact that investors must bear all market price risk under a constant premium regime.

Figure 5: Optimal Constant Premium (X)



Note: Figure displays constant premium (X) as /MWh required in addition to the prevailing market price for each value of α .

4.2.4. Comparing Policies

As discussed, the EMV and CE of investor remuneration varies to reflect the additional remuneration required to account for different levels of risk aversion. Similarly, the utility of policymaker subsidy cost will vary according to the EMV outlay required, along with the disutility associated with a given optimal degree of market price risk exposure. As absolute policy cost and utility of policy cost (i.e. incorporating risk exposure) are both of concern for policy decisions, overall optimality of policy choice will be discussed in terms of both EMV and the utility equivalent.

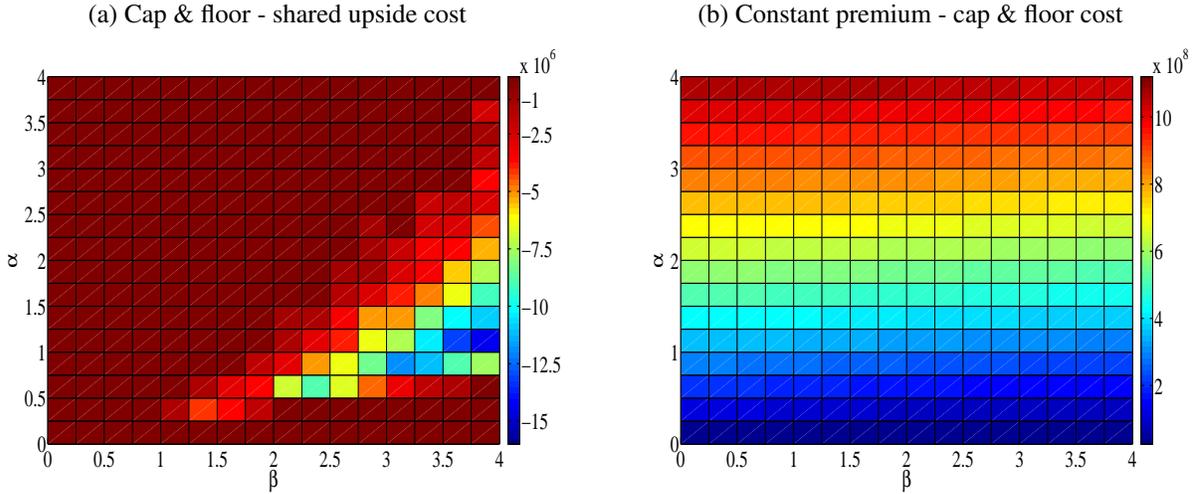
For both cap & floor and shared upside policies, Figure 6(a) shows that the EMV cost for a cap & floor policy is modestly less under all risk aversion combinations. This difference in policy cost is low when risk aversion parameters are of similar levels but increases when the policymaker risk aversion parameter is 2 or greater. As section 4.2.2 discussed, the price floor K is always lower for a cap & floor policy as investors receive all upside immediately in excess of the guaranteed minimum. This effect is exaggerated when the efficient price floor is lower due to a high degree of market upside being offered to investors. In such circumstances, a marginal reduction in the price floor has a greater impact on policy cost, as the foregone market remuneration has a higher probability of occurring. As such, the reduced cost of a cap & floor policy, relative to a shared upside policy, is greater when a greater share of market upside is offered to investors. However, this only prevails when α is greater than zero as the pattern of market price risk, and thus the difference in resulting utility, only occurs when investors are risk averse. When investors are risk neutral, they are indifferent to the pattern of remuneration and thus any difference in policy cost is negligible.

The difference in policy cost between cap & floor and constant premium policies is displayed in Figure 6(b), where absolute difference in cost is predicated primarily on the Investors' level of risk aversion (α). Constant premium policies have a similar cost to cap & floor policies when investor's are risk neutral (c.1.27% more expensive), rising to a 32% difference when investors have a risk aversion parameter of 4. Although a higher β yields a higher cap & floor policy cost and thus lessens the gap to the constant premium cost, this is not apparant in Figure 6 as this difference is greatly overshadowed by the differences between investor risk aversion parameters.

For shared upside and cap & floor policies, policymaker utility is very similar, with a difference of 0.00-0.07%. As such, the discussed differences in absolute cost may be more important when deciding between a cap & floor or shared upside regimes. Utility-based analyses are more appropriate for determining an efficient within-policy cap & floor or shared upside specification.

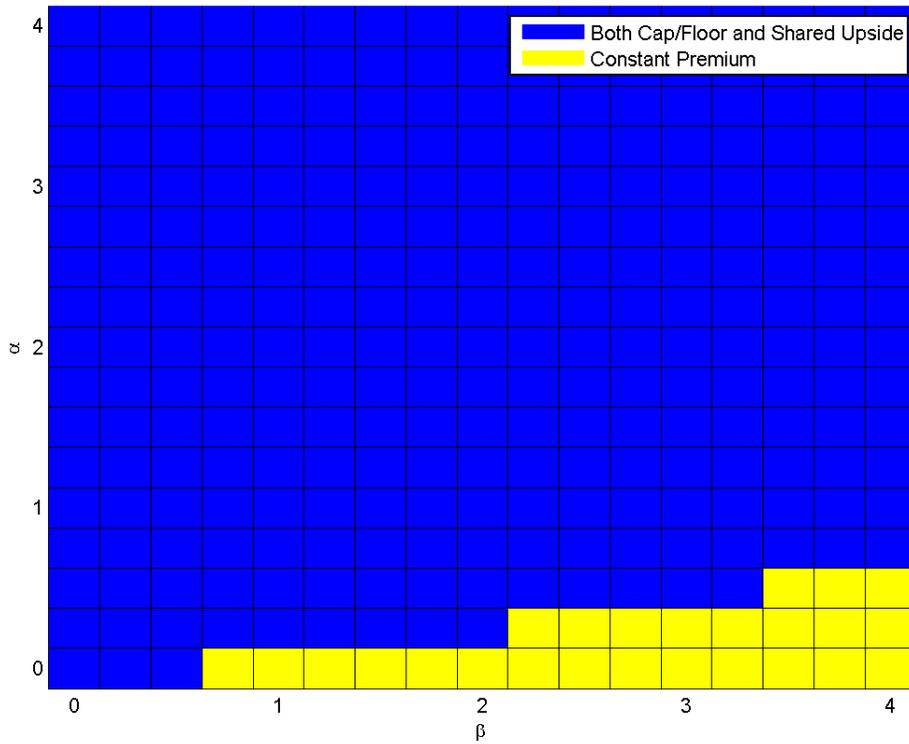
However, the utility derived from a constant premium policy differs greatly to that for a shared upside or cap & floor policy. Policymaker utility under a shared upside or cap & floor policy may be up to 7% more than for a constant premium policy. We compare policymaker's utility under cap & floor/shared upside policy with their utility under a constant premium policy in figure 7. We see

Figure 6: Difference in EMV policy cost



Note: Figure 6(a) displays, for each α/β combination, the cost of the cap & floor policy minus the cost of the equivalent shared upside policy. Figure 6(b) displays, for each α/β combination, the cost of the constant premium policy minus the cost of the equivalent shared upside policy. Cost is calculated as the Expected Money Value (EMV).

Figure 7: Policymaker preference: Baseline Scenario



Note: Figure displays the policy choice which yields the greatest utility for the policymaker. The difference in utility between cap & floor and shared upside policies is $\leq 0.03\%$ and thus these are assumed to have equal utility.

that a constant premium results in a greater level of net utility for the policymaker when investor risk is ≤ 0.5 , whilst policymakers must have a risk aversion parameter of 0.75 or greater. As expected levels of risk aversion hover about 1, this would suggest that investors must be indifferent to risk for a constant premium policy to be optimal. This is an important finding in relation to the common use of constant premium policies in many jurisdictions. This suggests that for such policies to be optimal, policymakers must be more than four times as risk averse as investors. If this is not the case, the disutility associated with the additional remuneration required for a constant premium tariff is greater than the foregone disutility associated with an alternate FiT structure, and thus a constant premium FiT is suboptimal.

This section has shown that intermediate division of market price risk is optimal when investor and policymaker risk aversion is of a similar magnitude, with a difference of $\leq 0.07\%$ between utility for shared upside or cap & floor regimes. On utility grounds, both return similar values under our baseline scenario. Modest cost differences occur when floor prices are low (likely to occur when policymakers are highly risk averse and high levels of market upside are offered to investors) and cap & floor policies thus result in a lower EMV cost. Constant premium policies are considerably more expensive than both shared upside and cap & floor policies in EMV terms. However, a constant premium policy may be preferred on utility grounds when investor's risk aversion is ≤ 0.5 and policymakers have risk aversion parameters in the region of 0.75 or greater. A sensitivity analysis will now analyse results when alternate ranges of risk aversion or alternate market conditions prevail.

5. Sensitivity analysis

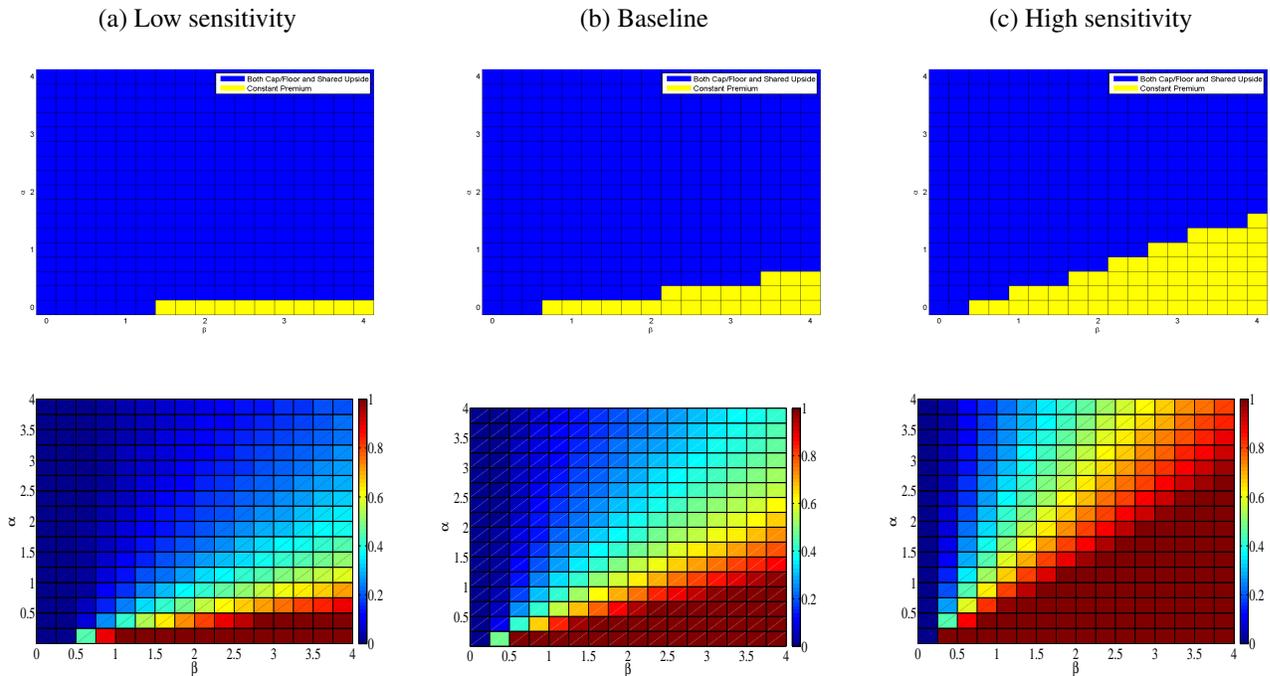
Different levels of calibrated risk aversion may result in different degrees of optimal market price risk apportionment. If FiT policy comprises a greater share of total electricity cost, policymakers may be more sensitive to bearing market price risk. Similarly, investor sensitivity may increase if they have a less diversified portfolio of investments and thus require a higher EMV in order to incentivise investment. Furthermore, the baseline scenario considered market price conditions representative of deployment in Ireland, with results potentially sensitive to alternate market assumptions. This section informs policy as to optimal FiT choice under alternate scenarios of calibrated risk aversion and market conditions.

We model a scenario of greater risk sensitivity by doubling the calibration parameters (w_{pre}^{policy} and w_{pre}^{inv}) and model lesser sensitivity by halving the calibration parameters. 'Low sensitivity' results are calculated where the calibration parameter is double the baseline level. For investor risk aversion, this results in the baseline range of risk premia of figure 2 falling to a range of 2.34-39%, with a value of 12% when $\alpha = 1$. For policymaker risk aversion, the baseline range of risk premia of table 2 fall to a range of 0.6-2.6%, with a value of 0.6% when $\beta = 1$. 'High sensitivity' results

are calculated where the calibration parameter is half the baseline level. For investor risk aversion, this results in the baseline range of risk premia of figure 2 rising to a range of 2.34-99%, with a value of 34% when $\alpha = 1$. For policymaker risk aversion, the baseline range of risk premia of table 2 rise to a range of 3-12.6%, with a value of 3% when $\beta = 1$.

5.1. Changes in the calibrated rate of policymaker risk aversion

Figure 8: Policymaker sensitivity to risk and FiT choice



Note: Investor risk aversion calibrated at baseline level for all scenarios in Figure 8. Policymaker risk aversion organised by column. Top row shows between-tariff optimality for each scenario. Difference in utility between cap & floor and shared upside policies is $\leq 0.03\%$ and thus these are assumed to have equal utility. Bottom row shows within-tariff division of market price risk using the shared upside regime. 'Low sensitivity' results are calculated where the calibration parameter is double the baseline level. For investor risk aversion. 'High sensitivity' results are calculated where the calibration parameter is half the baseline level.

Figure 8 shows the optimal FiT policy choice, both in terms of optimal between-tariff choice (cap & floor/shared upside or constant premium) and within tariff choice (division of market price risk when cap & floor or shared upside policies are optimal). For brevity of presentation, within tariff-choice is presented in the context of a shared upside policy alone. Inferences as to the equivalent cap and floor policy may be identified with reference to the relationships illustrated by figures 3 and 4.

Under all scenarios, constant premium policies are only optimal when policymaker risk aversion is greater than investor risk aversion. Figure 8 shows that when policymakers are less sensitive to risk, perhaps when renewables comprise a small proportion of total electricity cost, constant

premium policies are only optimal when investors are risk neutral. As policymakers are more sensitive to FiT cost uncertainty, perhaps due to increased deployment or low fossil fuel costs and thus a higher proportional burden, we find that constant premium policies are of greater importance. When policymakers are highly sensitive, we find that constant premium policies are optimal when investor risk aversion is around half that of policymaker risk aversion. As such, constant premium policies are of increasing importance as the burden of renewables policy increases. However, even with a doubling of the level of underlying sensitivity, constant premium policies are only optimal when policymaker risk aversion is much greater than investor risk aversion.

Figure 8 also shows the division of market price risk when shared upside policies are chosen for each of these policymaker wealth scenarios. When policymaker sensitivity is low, a flat rate FiT or low share of market upside for investors is generally optimal. As policymakers become more sensitive to market price risk, a higher θ/cap value and thus lower K guarantee is required for efficient division of market price risk.

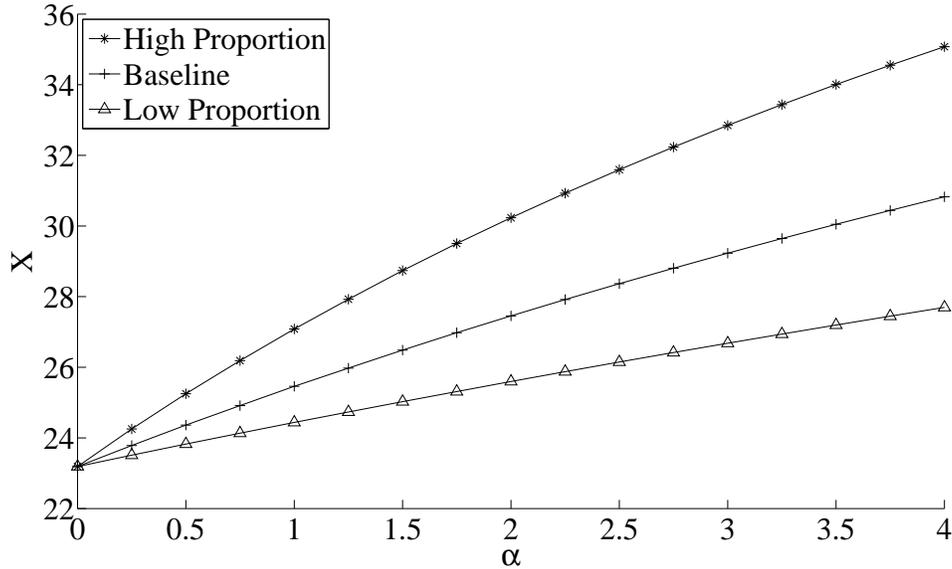
Figure 8 shows that as policymakers become more sensitive to market price risk, the optimal division of market price risk evolves from zero to gradually incorporate varying degrees of market upside for many risk aversion combinations. Such changes in sensitivity may occur due to an increasing renewables subsidy burden as deployment progresses. For prudent forward-looking policymakers, this finding shows that flexibility is required in legislative frameworks, such that divisions of market price risk may be augmented to accommodate this evolving optimality.

5.1.1. Changes in the calibrated rate of investor risk aversion

Unlike changes in policymaker risk sensitivity, optimal constant premium policies will change with changes in investor risk sensitivity. Figure 9 shows that a greater constant premium (X) is required as investor risk sensitivity grows, with this difference greater for higher levels of risk aversion.

Analysing between-policy FiT choice, Figure 10 shows that as investors become more sensitive to market price risk, the scope for a constant premium FiT diminishes. This is in contrast to a changes in policymaker risk sensitivity. As renewables deployment matures, FiT costs are likely to comprise both a greater proportion of a policymaker's electricity budget and a lesser proportion of investors' budgets, as larger, less specialised developers who are more diversified may enter the industry. As such, investor risk aversion falls whilst policymaker risk aversion rises, suggesting that the scope for premium policies may grow as both sensitivity analyses would suggest. Indeed, if both investor sensitivity falls and policymaker sensitivity grows, the magnitude of this growth may of an even greater extent than that described.

Figure 9: Optimal Constant Premium (X) for different levels of investor risk sensitivity



Note: Figure displays constant premium (X) as /MWh required in addition to the prevailing market price for each value of α .

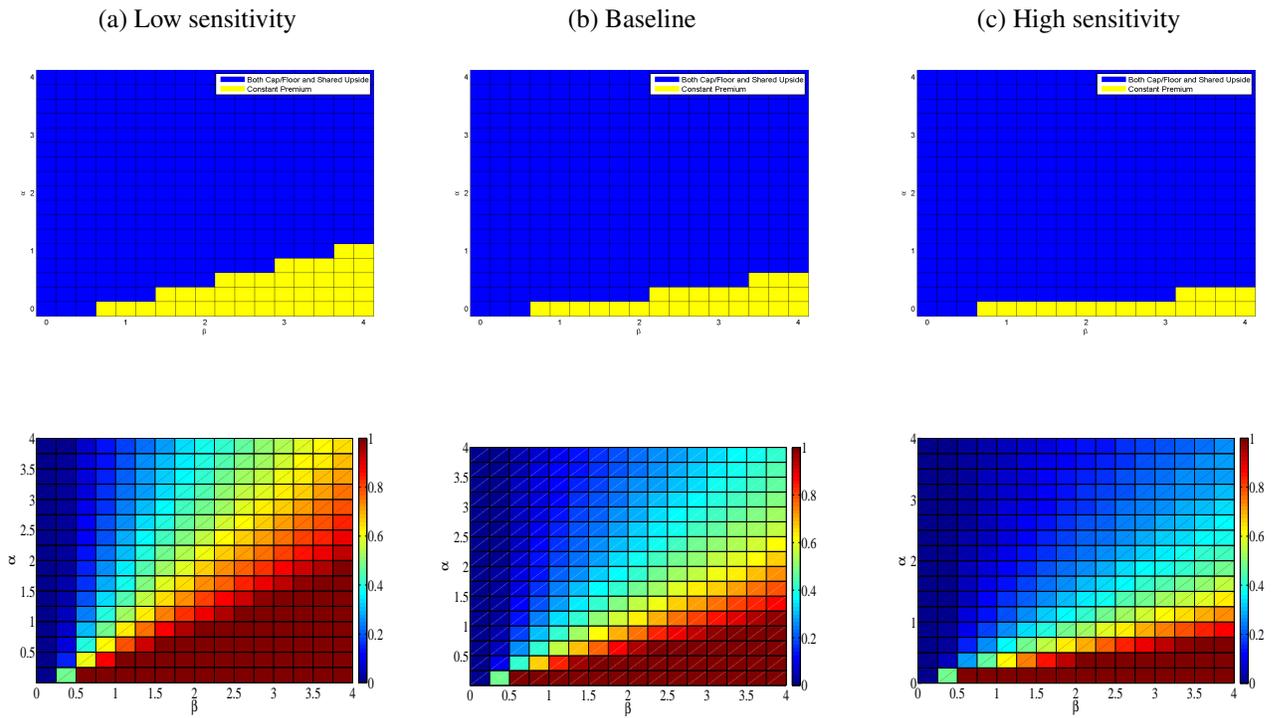
5.2. Sensitivity of policy choice to changes in market parameters

Sensitivity to market price parameters is tested by, holding all other factors constant, doubling the rate of growth or volatility in the Geometric Brownian Motion market price process. Figure 11 shows the change in a constant premium as market price growth and volatility change. An increase in the rate of market price growth shifts the required premium downwards. Relative to the baseline scenario, increasing risk aversion causes the required premium to grow at a greater rate when the underlying rate of price growth is higher. This suggests that the premium policy is more sensitive to change in investor risk aversion when the underlying rate of growth is higher.

Similarly, the required constant premium is more sensitive to changes in investor risk aversion when the underlying rate of volatility is higher. Figure 11 shows that increasing the rate of volatility has a greater proportional impact than increasing the underlying rate of growth when α is ≥ 2 . This suggests that the underlying rate of volatility is of greater importance when setting a constant premium tariff, especially when investor risk aversion is expected to be high.

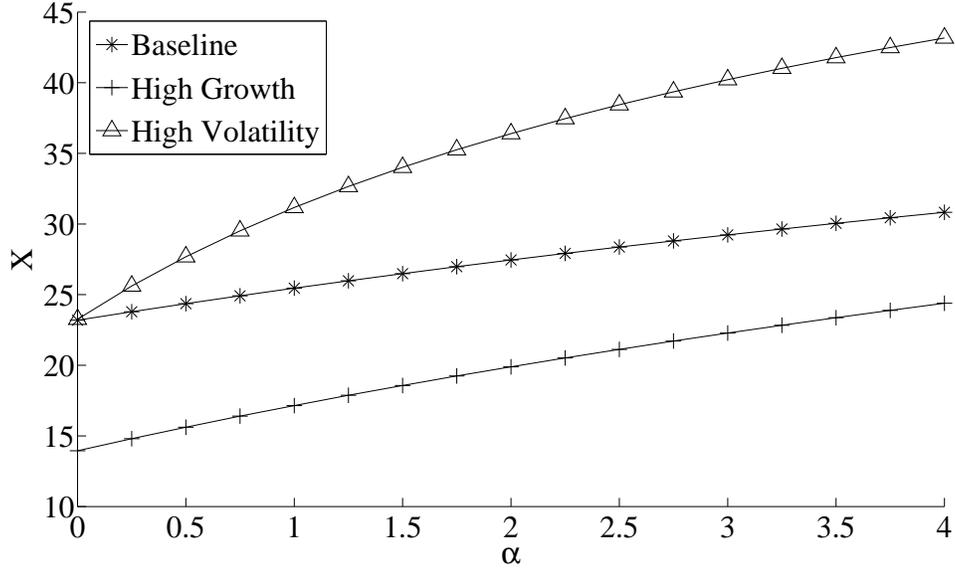
Figure 12 demonstrates the sensitivity of between and within-tariff choice to a doubling of either the rate of volatility or growth in market prices. Analysing the division of market price risk in Figure 12 shows that both scenarios show a very modest shift in the division of risk towards the policymaker, with fixed price and low θ FiTs being of slightly greater prevalence. Constant premium policies are optimal only when investors are risk neutral or extremely risk averse. For increased growth, this may be due to the lower level of subsidy and thus lower policymaker risk.

Figure 10: Investor sensitivity to risk and FiT choice



Note: Policymaker risk aversion calibrated at baseline level for all scenarios in Figure 10. Investor risk aversion organised by column. Top row shows between-tariff optimality for each scenario. As before, the difference in utility between cap & floor and shared upside policies is $\leq 0.03\%$ and thus these are assumed to have equal utility. Bottom row shows within-tariff division of market price risk using the shared upside regime. 'Low sensitivity' results are calculated where the calibration parameter is double the baseline level. 'High sensitivity' results are calculated where the calibration parameter is half the baseline level.

Figure 11: Optimal Constant Premium (X) for different market conditions



Note: Figure displays constant premium (X) as €/MWh required in addition to the prevailing market price for each value of α .

As such, optimality is shifted towards lower θ values. For scenarios of increased volatility, this may be attributable to increased market price risk and thus greater influence of the investor in determining the optimal division.

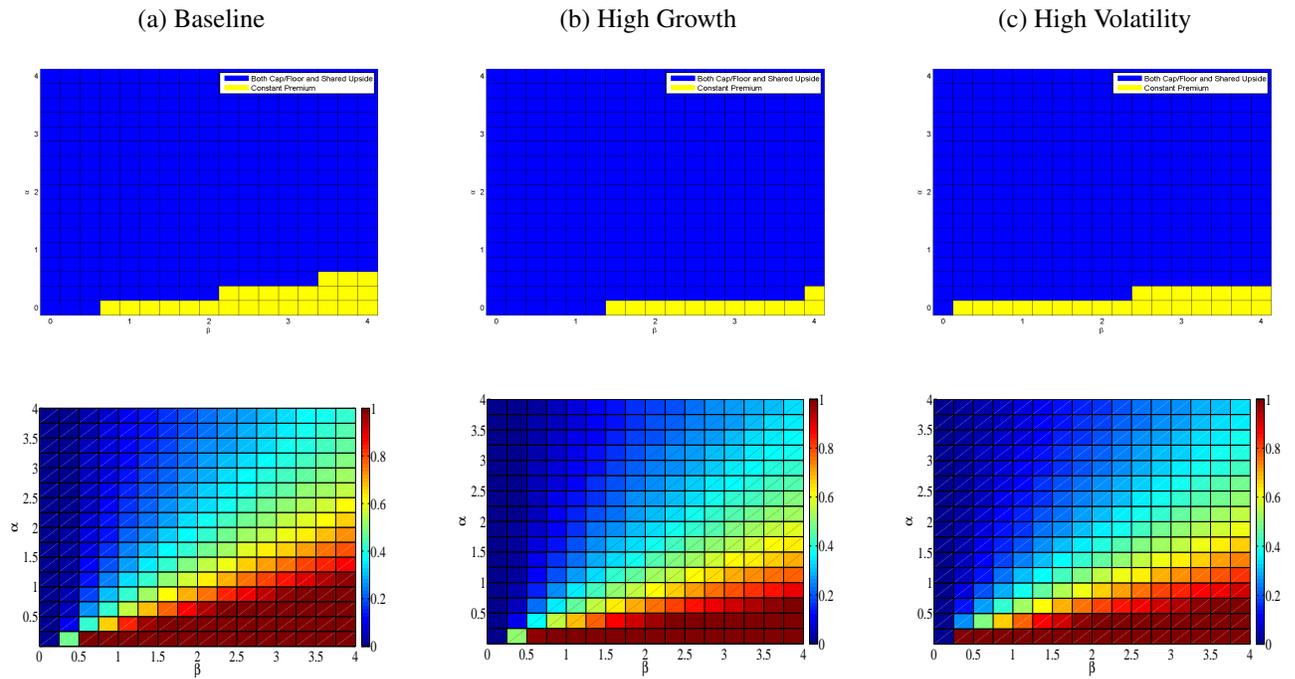
6. Conclusion

Feed-in Tariffs are a favoured renewable energy support scheme due to their ability to mitigate market price risk for potential investors. This risk is transferred through a policymaker to a counterparty, often the consumer. Different FiT designs transfer this risk in different ways. This paper has contextualised the optimal use of each FiT design with respect to investor and policymaker exposure to market price risk.

Optimal FiTs are identified by setting up renewable energy investment as a strategic leader game. Investors install a given quantity in order to maximise utility, with policymakers observing this response and specifying a FiT price to meet policy targets. Risk aversion is modelled using a Constant Relative Risk Aversion (CRRA) utility specification, calibrated to degrees of risk aversion observed in the literature. Alternative levels of risk aversion are captured through a wide spectrum of risk aversion parameters and sensitivity analyses. We characterise the spectrum of market price risk division for three classes of FiT. We analyse constant premium, shared upside and cap & floor policies alone and together.

We find that investor preferences are more influential than those of the policymaker when de-

Figure 12: Sensitivity to change in market parameters



Note: Market analyses organised by column. Top row shows between-tariff optimality for each scenario. As before, the difference in utility between cap & floor and shared upside policies is $\leq 0.03\%$ and thus these are assumed to have equal utility. Bottom row shows within-tariff division of market price risk using the shared upside regime. 'High volatility' results are calculated by doubling the rate of volatility relative to the baseline value of Table 1, holding all else constant. 'High growth' results are calculated by doubling the rate of growth relative to the baseline value, holding all else constant.

degrees of risk aversion are of a similar magnitude. Under our baseline assumptions, market price risk should be shared except under circumstances of extreme investor/consumer indifference to risk. This suggests that commonly employed fixed price and constant premium policies are sub-optimal unless investors or consumers are risk neutral. We find that cap & floor policies offer a similar but consistently lower level of utility to shared upside policies. This is because the different pattern of risk sharing requires a slightly lower minimum price guarantee under a cap & floor regime. This impact is emphasised when efficient prices are lower, an occurrence which is more likely to prevail when policymakers are extremely risk averse and investors are modestly risk averse. In Expected Money Value (EMV) terms, constant premium policies are always more expensive than those that share market upside, but offer higher utility when policymakers are risk averse and investors have low levels of risk aversion. Efficient division of market price risk is of increasing importance as policymakers and investors are more sensitive to market price risk, with policymaker sensitivity of greater influence. Such sensitivity may change as renewables deployment grows and becomes a larger share of total electricity cost. For many risk aversion scenarios, the optimal division of market price risk transitions through a wide spectrum of possible levels as such sensitivity changes. This has implications for both current and future policymaking. First, this suggests that consideration of optimal market price risk is of increasing importance as renewables deployment grows. Second, current policy should anticipate such a potential requirement and put in place flexible legislative measures to accommodate market price risk division if required.

Renewables deployment has continued at great pace in many jurisdictions, with FiTs the predominant support measure and growing in influence. Cited as a hedge against fossil fuel market price fluctuations, the relative benefit of renewables has been under increasing strain with the international proliferation of low-cost unconventional gas and depressing effect this has had on electricity prices. Not only has this potentially reduced the hedge value of renewables, the potential risk of high subsidy cost has become a greater concern in many jurisdictions. Such concerns may grow with increasing renewables penetration. This paper presents a means for policymakers to consider environmental policy in the context of such risks. Through the modelling framework presented, we provide an economic rationale for optimal FiT specification with which a policymaker may make a more informed decision as to both the level and format of a chosen FiT.

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