Dynamic Feed in Tariff Price Adjustments for the Rooftop PV Market in Germany

- A system dynamics approach[1] -

Amin Al Yaquob
Graduate School of Policy and Management
Doshisha University
Kyoto, Japan
kbj1052@mail3.doshisha.ac.jp

Kaoru Yamaguchi
Japan Futures Research Center
Awaji, Japan
director@muratopia.org

Abstract

This paper discusses the feed in tariff policy for the rooftop photovoltaic market in Germany. It attempts to explain the fluctuation pattern of the PV deployments occurred between 2011 and 2014. The study aims to figure out the basic system structure behind this phenomenon, and suggest a way to reduce the fluctuations and stabilize the PV market growth. System dynamics method is used to build a simulation model as an alternative to optimization method used in earlier research. The simulation model successfully replicates the historical behavior. The model results were then analyzed to enhance feed in tariff policy design to have a dynamic and real-time feed in tariff policy instead of stepped and discontinuous one. The study concludes that dynamic price adjustments can significantly improve the stability of the market growth. Dynamic price adjustment can provide more cost-effective policy and provide reliable market projections for policy makers.

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1. Introduction

Feed in tariff is one of the successful renewable energy policies that contributed to accelerating the diffusing renewable energy around the world. It has been implemented in more than one hundred countries and states (Couture et al. 2010). The policy also has been successful in reducing the technology cost, increase the technological efficiency and innovation in its related industries (Campoccia et al. 2014). Feed-In Tariff (FIT) policy drives market growth by providing developers long-term purchase agreements with fixed tariffs for the sale of electricity generated from renewable energy (RE) sources (Menanteau, Finon, and Lamy 2003). The policy contract usually lasts between 10 to 25 years (contract period is also referred as feed in tariff term). For each renewable energy technology, the tariff price differs and is determined by different factors, like technology cost, efficiency level, technology manufacturing maturity stage, in addition to the size and location of its power plant. As cost declines and technology efficiency increases, the feed in tariff prices is adjusted accordingly at the end of the feed in tariff qualifying period to guide the market development as intended. The reduction rates of feed in tariffs are called degression rates and are determined by the authority in charge of the policy (Klein 2012).

Germany is one of the leading countries that implemented the feed in tariff policy to boost renewable energy development. The solar photovoltaic market in Germany has been mainly driven by the feed in tariff policy since the year 2000. The German government introduced capacity corridor to guide the supply development to be within 2.5 and 3.5 Giga-watt (GW) per a year (Duetche Bank 2012). Nevertheless, the deployment quantities in the years of 2010 and 2011 have exceeded 7.5 GW. Such unexpected market response requires urgent policy intervention because the cost implication may increase the budget in the magnitude of billion of dollars (Chowdhury, Sumita, and Islam 2012; Frondel, Schmidt, and Vance 2014).

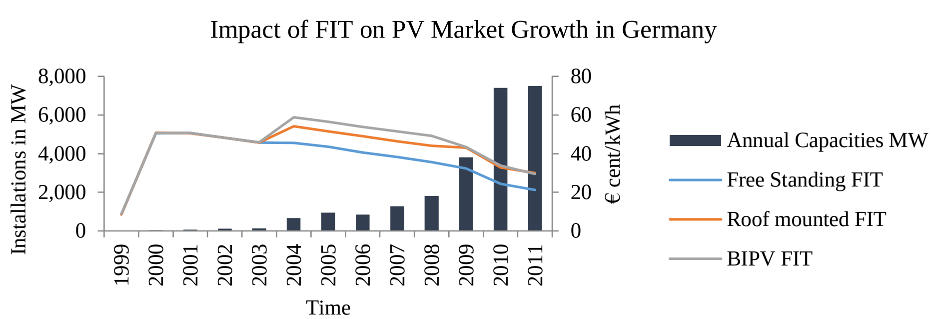

Figure 1: Impact of FIT on PV market growth in Germany

Source: (Jacobs 2012)

As the feed in tariff policy budget is paid by the electricity consumers and or taxpayers. An unexpected increase in renewable energy supply can result in the sudden increments in the electricity prices or taxes

(Frondel, Ritter, and Schmidt 2008). The fact that feed in tariff policy is a long-term contract creates a policy trap for governments and create a long-term burden on the public. Therefore Missing the right time to adjust the feed in tariff prices results in substantiative increase policy cost (Nemet 2009; Jacobs 2012). The feed in tariff policy must be adjusted dynamically and efficiently.

Rooftop PV market in Germany constitutes around 30% of the total PV installations in Germany. Thanks to high levels of feed in tariff, the cost of rooftop PV systems in Germany has witnessed a continuous decline. However, the pattern of rooftop PV follows a cyclic pattern with spikes before price adjustments. This pattern appears as project developers observe the declining cost and wait for the best time to install their projects, or they rush to install more projects at the end of the qualifying period (Grau 2014).

Unlike large-scale photovoltaic projects, small-scale projects have a shorter development time and hence respond quickly to policy changes. The rush to install behaviour is explained by three observations: 1) deployments increases with profit levels proportionally, 2) profit expectations decrease over time and 3) deployment accelerates right before the tariff price adjustment deadlines to benefit from high tariff prices, creating a rush to install effect (Grau 2014). According to the estimates, a rooftop PV installation project has a construction time between 15 to 3 weeks and an average of 7 weeks.

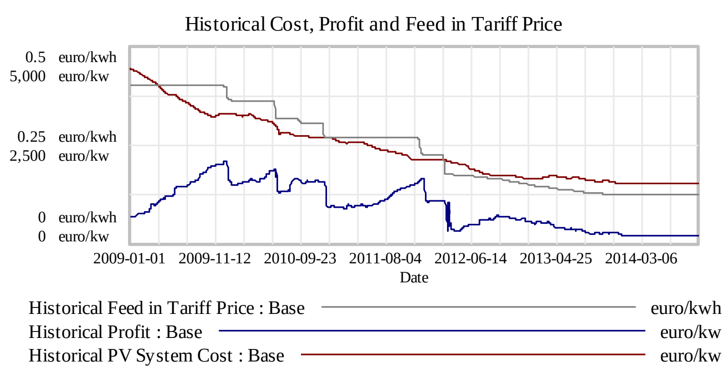

Figure 2: Feed in tariff is adjusted to cope with declining PV system cost

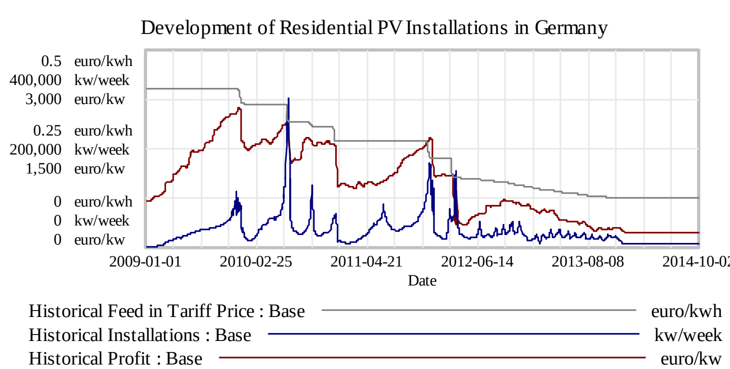

Figure 3: Weekly deployment levels of photovoltaic projects in German

2. (Grau, 2014) Model

A regression model was used to estimate the deployment based on profit level. The model is enhanced to model the rush to install effect using an optimization technique, where developers will decrease the construction time to the minimum possible to ensure the highest level of profitability. Although the results obtained from the optimization model replicate historical patterns fairly well, the model has a shortcoming that it does not incorporate developers' expectations of cost and price adjustments and the delay time needed to form these expectations. Therefore, the model assumes perfect decision making for the PV developers. As explained by (Sterman 2000) optimization techniques considers perfect outcomes and ignores the operational processes in the decision making, as well as imperfections and the effect of bounded rationality.

In (Grau 2014) model the installation rate is calculated using the following:

$$Y_{t+d} = \alpha * \pi_{t+d} - c$$

Where, Y_{t+d} is the installation quantity, π_{t+d} is the profit, and α and c are parameters. The net profit is given by:

$$\pi_{t+d} = v_{t+d} - p_t$$

Where, v_{t+d} is the present value, and p_t is the average system cost. The present value is then formulated as:

$$v_t = f_t * h * \sum_{j=0}^{n} (1+i)^{-j}$$

Where, f_t is the feed in tariff price at time *t*, and h is the average operational hours per a year, *i* is the interest rate and j is the feed in tariff term. The feed in tariff price data is given in the figure, facility operational hours is estimated with 900 kilo watt hour (kWh) per kilo watt kW system per a year. The interest rate is assumed to be fixed at 3.5%, and the feed in tariff term for residential roof top photovoltaic projects is 20 years.

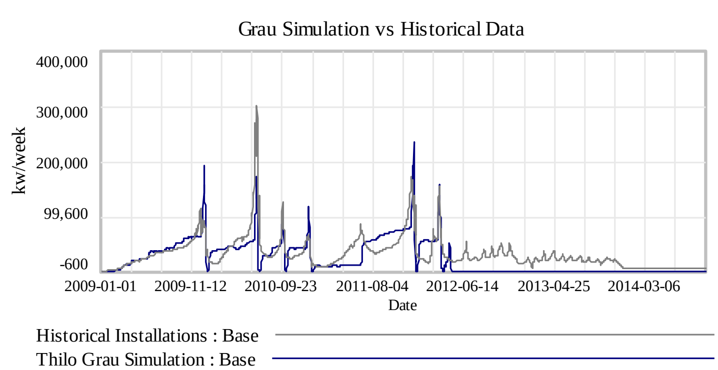

Figure 4: Comparison of (Grau, 2014) simulation and weekly historical installation of rooftop PV in Germany

3. System Dynamics Approach

The causal loop diagram shown in the figure below explains the growth of the deployment. As the first observation suggests, the level of profitability gained by the investors and developers mainly influences the deployment of PV projects. The economies of the scale of PV installations helps in reducing the overall cost of PV projects and consequently the increase the profit levels, as illustrated in the reinforcing loop R1. The project cost in turn reduces the generation cost (known as the Levelized Cost of Electricity Generation or LCOE) and consequently the feed in tariff price. The tariff rate is adjusted discretely (or stepped fashion) after a certain delay, called qualifying period. The price adjustment is determined by the generation cost and predefined internal rate of return (IRR[2]). The price adjustment loop B1 helps to correct the incentive level to make sure that the deployment levels as intended by the policymakers.

Nevertheless, the delay in systems usually creates fluctuations (Sterman 2000). Given the market growth loop, we can assume that the cost will have a declining trend (with some fluctuation resulted from market forces), and this allows more profit gains for the investors and developers. Consequently, the period before the price adjustment (usually price reduction) will provide the highest level of profitability. The profit to supply relationship developed by (Grau 2014) can be used to represent the inflow of a stock for intended projects. These projects, however, are realized depending on the construction time or project completion time decided by the developers. This allows us to explore the developers' decision in more details.

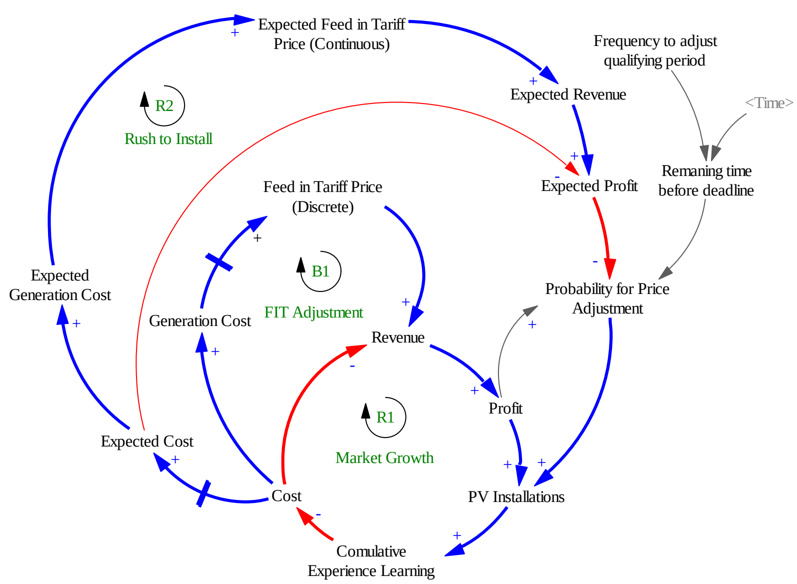

Figure 5: Model causal loop diagram

2 The IRR percentage in this model is estimated from historical data.

The project completion time is defined using the following relationship. Throughout the qualifying period, the project completion time is assumed to be the average, 7 weeks, however, as the remaining period before the price adjustment deadline becomes less than 7 weeks, the completion time is adjusted to be the maximum possible as shown in the figure below. The policy term or the qualified period can be used to set a timeframe for projects. That is the duration of a policy term (as shown in figure 6), provides an indicator or a deadline for project developers. Hence the variable "remaining time before the deadline" is devised to estimate how project developers plan their project schedules. When the remaining time before the deadline is less than 7 weeks, project completion can range between 7 and the minimum of 3 weeks using the relationship defined in figure 7. This relationship, however, is not sufficient to explain the non-linear behavior of weekly installations. The rush to install effect discussed above can be modeled using the developer expectation of cost and project profitability. Unlike fixed or discrete feed in tariff price schedules, estimation of continuous feed in tariff prices can provide an updated indicator of the likelihood of price changes.

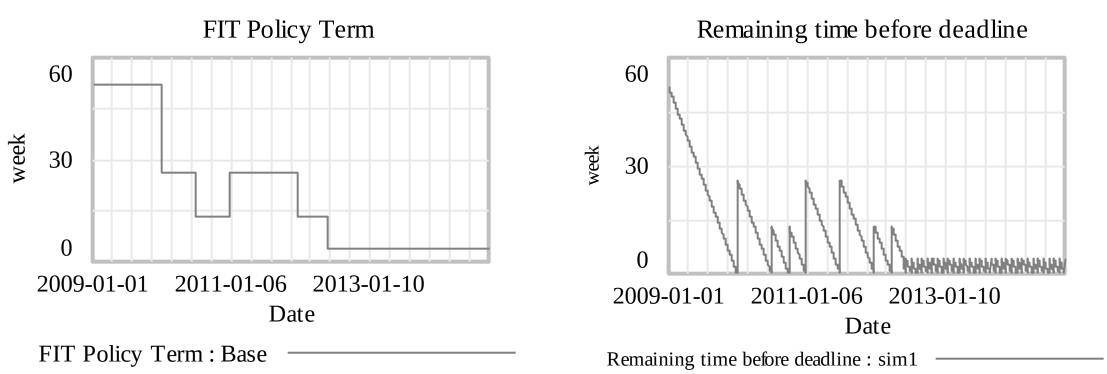

Figure 6: Designing the remaining time before the deadline

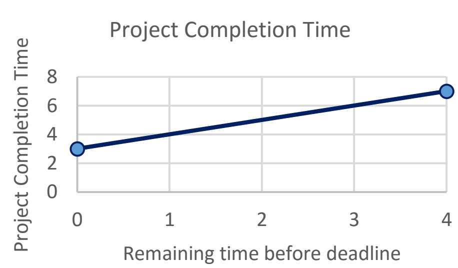

Figure 7: Project completion time

The likelihood indicator influences the developers to speed their project construction if profits are expected to decline in the future, vice versa. The likelihood can be represented as follow:

$$L = \frac{\pi}{\pi'}$$

Where L is the likelihood indicator, π is the project profit, and $\pi'$is the expected profit. Using the likelihood indicator, the developers form their expectations from the trend of profits as shown in loop R2 in the causal loop diagram.

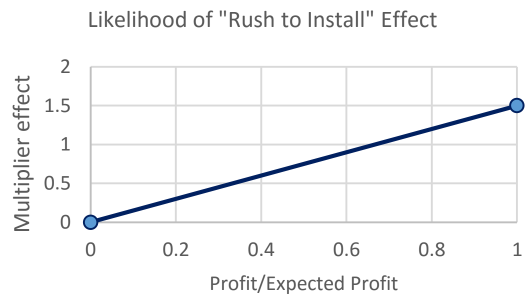

Figure 8: Rush to install effect

As the pattern shows, the developers' decision-making is influenced by time. Therefore, the probability multiplier impact is marginal except at the 3rd quarter of the qualifying period. For this reason, a corrective non-linear relationship is necessary. The following relationship in the figure below shows the impact of remaining time before the price adjustment on the probability multiplier. This relationship is formulated as follow:

$$e = L(R)$$

Where e is the effect of remaining time on the decision for project deployment, R is the ratio of remaining time. R is defined as:

$$R = \frac{t_R}{q_D}$$

Where t_R is remaining time befoe the qualified period deadline, and q_D is the qualified period duration.

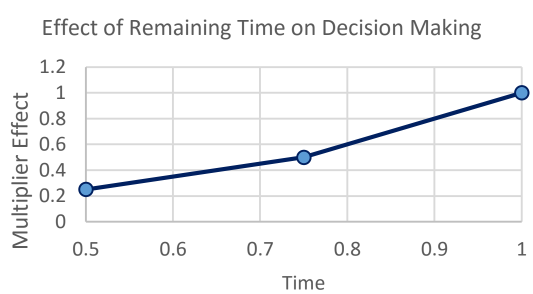

Figure 9: Effect of remaining time to complete projects

The interaction between these variables is explained in the stock flow diagram below. Note that the stock for the simulated installations of PV project is disaggregated into three stocks, since its pattern matches a second order material delay. The stock called "Installation before Connection" refers to the PV installations installed by the project developers before they are connected to the electric grid. This stock will be used to analyzing the PV installations pattern.

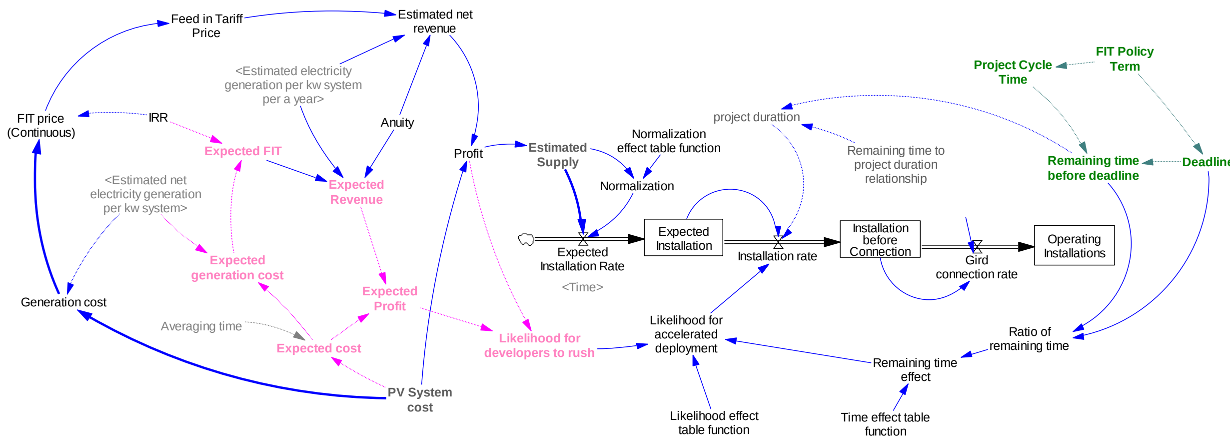

Figure 10: Stock flow diagram

4. Model Results

Using the incremental developers expectation about cost and profit to form their decision-making process, the model succeeded in replicating not only historical data but also the historical pattern and the logic behind it. This provides an alternative method to the optimization technique used by (Grau 2014). The figure below shows the expected profit which is developed from the parallel structure introduced in loop R2 and how it influences the likelihood for the rush to install effect. The simulated result of installations is shown in figure 12.

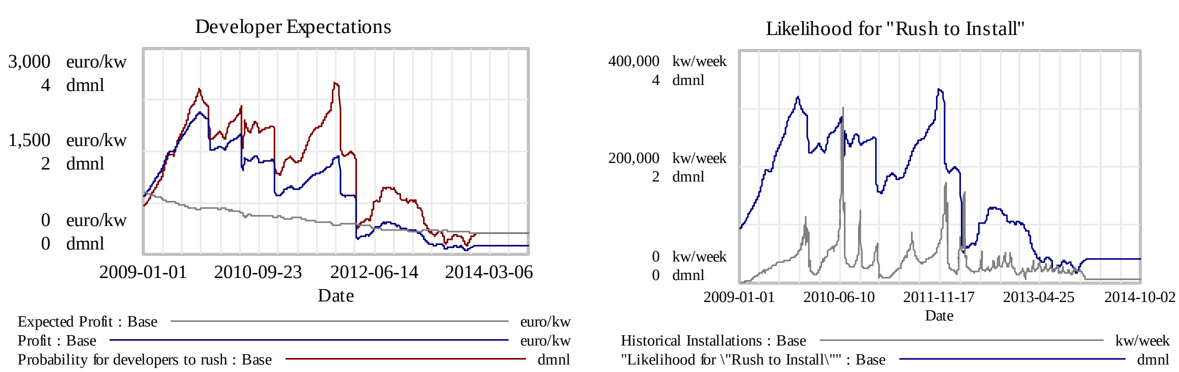

Figure 11: Project developer expectations and the likelihood of accelerated deployment

Using the understanding developed in the basic structure, the simulation results could replicate the installation pattern.

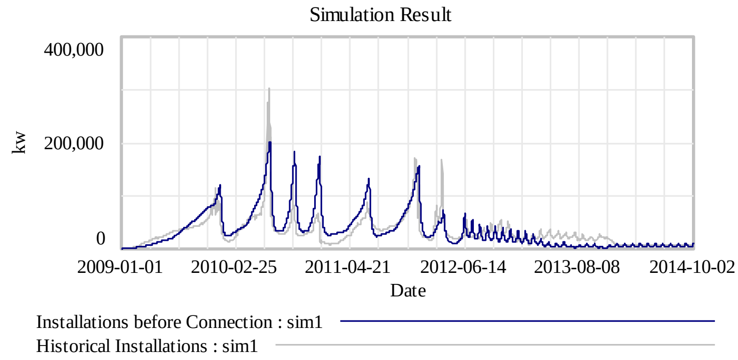

Figure 12: Model results

4.1 Discrete Feed in Tariff Policy

The PV system cost is a contributing variable to the design of feed in tariff policy. In order to see the impact of PV system cost changes, the changes have to be tested against responsive feed in tariff policy. Since the historical feed in tariff price data will not provide accurate results, the discrete model of the feed in tariff price adjustments is developed for this purpose. Due to the complexity of the feed in tariff pricing policy, a simpler model has been devised to testing purpose. The discrete model offers relatively accurate trend to the historical data.

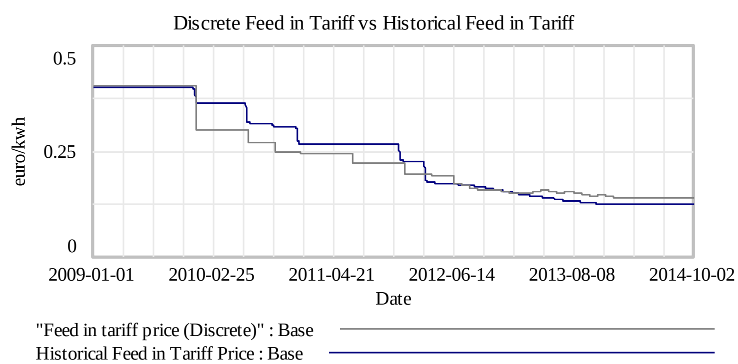

Figure 13: Feed in tariff comparison

4.2 Testing and Analysis for the Discrete (Stepped) Model

The model was tested using partial tests to verify its intended rationality. Specifically, the model was tested to examine its response to unexpected changes in system cost. This will be modeled using STEP function for the period between the 70th and 130th week. The results show reasonable behavior; the expected profits increases when the cost increase and vice versa. This is because the R2 loop of developer expectation dominates in the systems, in which the feed in tariff prices are adjusted accordingly to create a profitable margin. Moreover, the developer expectations are derived from an exponential averaging of PV systems cost.

Also, the model was tested against extreme values. Testing the model with large values of unexpected cost increases may lead to negative profits and consequently negative installation quantities. However, a normalization relationship is introduced to correct this issue. The simulation of the discrete policy provided excellent results similar to the historical pattern. However, to have an efficient policy the pattern has to be more stable against fluctuations.

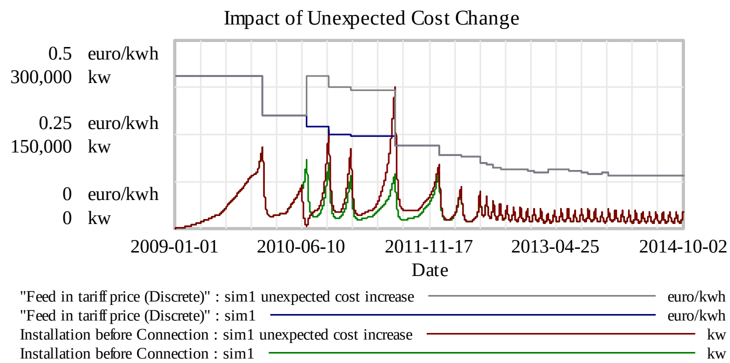

Figure 14: Impact of Unexpected Cost Change

4.3 Continuous (Smooth) Feed in Tariff Policy

The continuous feed in tariff policy assumes no deadlines for price adjustments. Similar to electricity prices, the tariff prices can determined depending on the updated cost of PV systems. This allows the policy to remove a critical delay that causes the fluctuations of PV deployment. Moreover, based on this assumption, as there are no deadlines, the majority of projects will have a completion time around the average of 7 weeks, and there will be no need to shrink this period. Consequently, there will be no effect of remaining time before the deadline, which is a major non-linearity in the discrete model that reinforces the deployment rate.

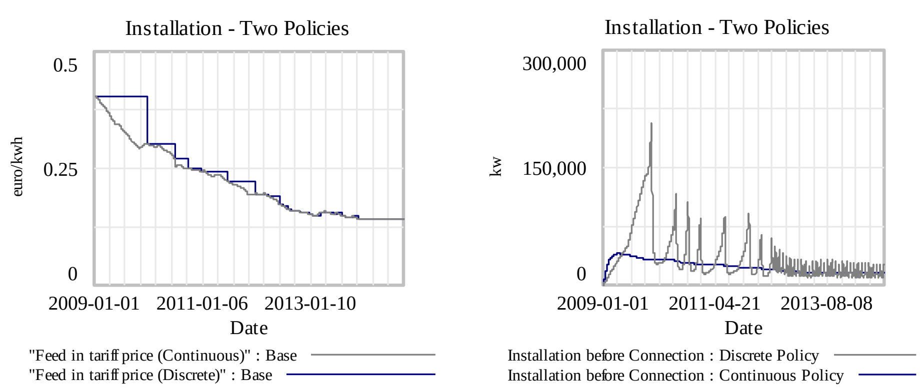

Figure 15: Impact of two policies

The results show that the continuous policy is more robust and stable to change. The following figure shows a STEP test of the cost increase of 50% between the 70th and 130th weeks. The developer expectation in the case of continuous price adjustments stabilizes. The probability to rush becomes marginal as the model eliminate the effect of remaining time.

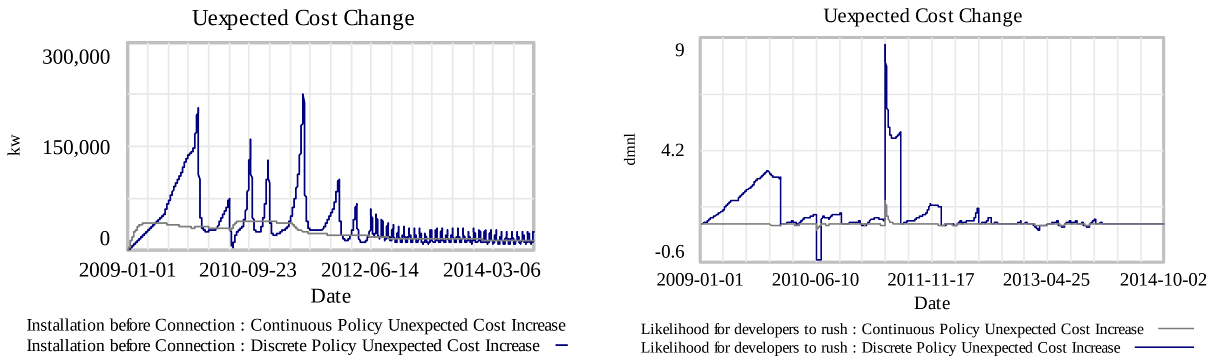

Figure 16: Unexpected cost change on PV installations

4.4 Comparison of Continuous and Discrete Policy

When comparing the results of the two policies, it is clear that the continuous policy can reduce substantive policy costs. The policy budget to be realized by the end of the 2015 policy term (i.e. after 20 years) will in the year of 2035. Discrete feed in tariff policy can introduce faster share of solar energy with the fluctuating pattern as the growth is highly motivated by profit and unpredictable market conditions. Whereas continuous policy offer slower but more reliable pattern, that prioritize cost efficiency rather than the speed of renewable energy deployment. According to the model results, the discrete policy can achieve an operating capacity of 10 GW by October 2014 at a policy budget of around 5 trillion euros, while the continuous policy achieves 7 GW at the same period with a half the budget.

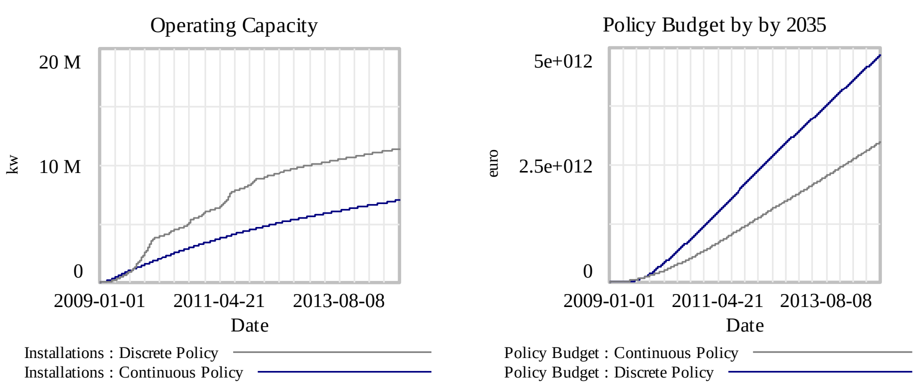

Figure 17: Policy budget comparison

5. Summary and Conclusion

The paper discussed the influence of feed in tariff policy on the development of rooftop PV in Germany. Feedback loop analysis was used to identify issues incorporated in the discrete based feed in tariff policy. We found that time delays and nonlinearities were a major cause for the cyclic fluctuations development trend of PV deployments. The system dynamics model developed in this paper was capable of generating historical pattern and allowed discrete and continuous policy comparison. The model showed how continuous price adjustments could improve market growth while maintaining the policy budget under control.

Acknowledgement

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[3] The sponsor of this research does not influence the research results and is not accountable for its outcome.

Appendix A

Comparison between our model and Grau model against historical data.

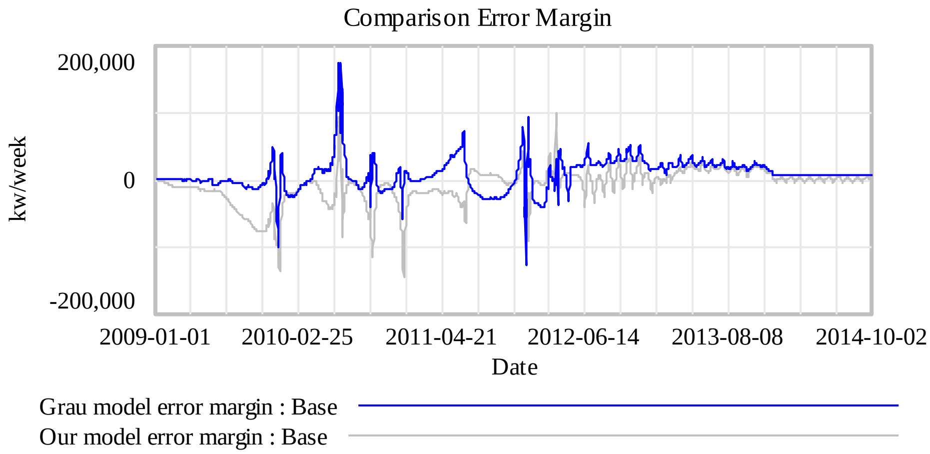

Figure 18: Simulation comparison showing the error margin between Grau and our models

6. Appendix B

System Dynamics Model Documentation

```
"1 - increase in cost"=
                    step(1, 0)+step(0.5, Time of change)-step(0.5, Time of change2)
          Units: dmnl

"2- decrease in cost"=
          step(1, 0)-step(0.2,Time of change)+step(0.2,Time of change2)
Units: dmnl

"3- Variable change"=
          smooth3(random uniform(0,1,1),16)
Units: dmnl

Alternating=
          if then else(modulo(Time, FIT Policy Term)=0,pulse(Time, 0.1),0)
Units: dmnl

Anuity=
          14.7
Units: dmnl

Averaging time=
          2
Units: week

Change=
          if then else(Switch for response to cost change=0, 1,
          if then else(Switch for response to cost change=1,"1 - increase in cost" ,
          if then else(Switch for response to cost change=2, "2- decrease in cost",
"3- Variable change")))
Units: dmnl
Switch for testing the system response to chnage in cost. 0: no
                    change, 1: step increase, 2: step decrease, 3: varibale change
                    using random parameter.

Connected and Operating Installations= INTEG (
          connection,
                    0)
Units: kw

connection=
          Installation before Connection/per week
Units: kw/week

Deadline=
          FIT Policy Term
Units: week

difference=
          "Feed in tariff price (Discrete)"-"Feed in tariff price (Continuous)"
Units: euro/kwh

effect df(
          [(0,0)-(1,1)],(0,0),(1,1))
Units: dmnl

Estimated cost=
```

param c*exp(param d*Connected and Operating Installations)
Units: euro/kw

Estimated electricity generation per kw system per a year=
Annual operation time in hours*kw kwh
Units: kwh/kw

Estimated net electricity generation per kw system=
Annual operation time in hours*Facility life time in years*kw kwh
Units: kwh/kw
Annual operation time in hours*16*kw kwh

Estimated net revenue=
Feed in tariff price*Estimated electricity generation per kw system per a year
*Anuity
Units: euro/kw
if then else(Time<260,900*20*FIT price, 900*20*Feed in tariff
box*(1-anuity))

Estimated Supply=
(param a*(Profit)-param b)
Units: kw/week
-399998x + 861573 954684*exp(-0.714*(Project cost/Quantity of
approved projects)) param a*LN(Profit NPV)-param b supply
rel(Profit NPV) if then else(switch three=0, (param a*Historical
Profit)-param b, (param a*Profit NPV)-param b)

Expected cost=
smooth(PV System cost, Averaging time)
Units: euro/kw

Expected FIT=
Expected generation cost*(1+IRR)
Units: euro/kwh

Expected generation cost=
((Expected cost+operation cost)/Estimated net electricity generation per kw system
)
Units: euro/kwh

Expected Installation= INTEG (
Expected Installation Rate-Installation rate,
initial capacity)
Units: kw

Expected Installation Rate=
Estimated Supply*Normalization
Units: kw/week

Expected Profit=
Expected Revenue-Expected cost
Units: euro/kw
DELAY3(Expected Revenue-Expected cost, 6)

Expected Revenue=
Estimated electricity generation per kw system per a year*Expected FIT*Anuity
Units: euro/kw

Feed in Tariff Degression Rate=
difference*Alternating/TIME STEP
Units: euro/kwh/week

```
(difference)*Alternating*16/per week

Feed in tariff price=
        if then else(Feed in tariff switch= 0,"Feed in Tariff Price (Historical )"
 ,
        if then else(Feed in tariff switch= 1, "Feed in tariff price (Discrete)",
"Feed in tariff price (Continuous)"))
Units: dmnl

"Feed in tariff price (Continuous)"=
        Generation cost+(Generation cost*IRR)
Units: euro/kwh
if then else(Time<260, Historical Feed in Tariff Price,
                Generation cost+(Generation cost*IRR))

"Feed in tariff price (Discrete)"= INTEG (
        -Feed in Tariff Degression Rate,
                "Feed in tariff price (Continuous)")
Units: euro/kwh

"Feed in Tariff Price (Historical )"=
        fit historical dt(Time)
Units: euro/kwh

Feed in tariff switch=
        1
Units: **undefined** [1,2,1]
0 for historicla 1 for discrete 2 for continuous

FIT Policy Term=
        if then else(Time<52, 52,
        if then else(Time<75, 26,
        if then else(Time<104, 13,
        if then else(Time<156, 26,
        if then else(Time<178, 13,4)))))
Units: week [4,52,4]
if then else(Time<24, 12, if then else(Time<60,6, 3))

Generation cost=
        ((PV System cost+operation cost)/Estimated net electricity generation per kw system
)
Units: euro/kwh
if then else(Time<261, Historical cost/estimated net electricity
                generation per kw system, (Project cost+operation
                cost)/estimated net electricity generation per kw system)

Historical Installations=
        Historical Installation dt(Time)
Units: kw/week

initial capacity=
        1
Units: kw

Installation before Connection= INTEG (
        Installation rate-connection,
                0)
Units: kw

Installation rate=
        (Expected Installation/project durattion)*Likelihood effect
```

Units: kw/week

IRR=
    0.075
Units: dmnl
Initial IRR*(1-(Installation/Goal))

Likelihood effect=
    Likelihood effect table function(Likelihood for developers to rush)*Time effect
Units: dmnl

Likelihood effect table function(
    [(0,0)-(1,2)],(0,0),(1,1.5))
Units: dmnl

Likelihood for developers to rush=
    Profit/Expected Profit
Units: dmnl

Normalization=
    effect df(Estimated Supply)
Units: dmnl

operation cost=
    PV System cost*operation cost percentage
Units: euro/kw

operation cost percentage=
    0.525
Units: dmnl

param a=
    if then else(Time<52, 50, 50)
Units: (kw*kw)/(euro*week)

param b=
    890
Units: kw/week
if then else(Time<=52, 37250,890)

param c=
    3813.9
Units: dmnl

param d=
    -9e-008
Units: dmnl

per week=
    1
Units: week

Policy Budget= INTEG (
    Connected and Operating Installations*Estimated net revenue,
        0)
Units: euro

Profit=
    Estimated net revenue-PV System cost
Units: euro/kw
if then else(Time<261, estimated net revenue-Historical cost,)

Project Cycle Time=
if then else(modulo(Time, FIT Policy Term)=0,0, modulo(Time, FIT Policy Term
))
Units: week

project durattion=
if then else(Feed in tariff switch =2,7, Remaining time to project duration relationship
(Remaining time before deadline))
Units: week

PV System cost=
if then else(Switch System Cost=0, "PV System Cost (Historical)"*Change,
Estimated cost)
Units: euro/kw
The system cost can be either set to historical cost to validate
the model against the historical data using (Parameter
a*exp(Parameter b*Installations))*Change or to set it a
regression model to allow a feedback loop.

"PV System Cost (Historical)"=
Historical Cost Data(Time)
Units: euro/kw

Ratio of remaining time=
1-(Remaining time before deadline/Deadline)
Units: dmnl

Remaining time before deadline=
(Deadline-Project Cycle Time)
Units: week

Remaining time to project duration relationship(
[(0,0)-(10,10)],(0,3),(4,7))
Units: week

Switch for response to cost change=
0
Units: dmnl [0,4,1]

Switch System Cost=
0
Units: dmnl [0,1,1]
0: Historical Cost 1: Estimated Cost using a regression model

Thilo Grau Simulation=
Thilo Grau Model Simulation dt(Time)
Units: kw/week

Time effect=
if then else(Feed in tariff switch=2, 1, Time effect df(Ratio of remaining time
))
Units: dmnl

Time effect df(
[(0.5,0)-(1,1)],(0.5,0.25),(0.75,0.5),(1,1))
Units: dmnl

Time of change=
75
Units: week

Time of change2=
120
Units: week

TIME STEP = 0.0625
Units: week [0,?]
The time step for the simulation.

7. Bibliography

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