RENEWABLE ENERGY POLICY AND INVESTMENT DECISION-MAKING IN ELECTRICITY MARKETS

A Dissertation

Submitted to the National Graduate Institute for Policy Studies (GRIPS)

in Partial Fulfillment of the Requirements for the Degree of

Ph.D. in Public Policy

by

Kazuya Ito

March 2022

Abstract

To achieve further decarbonization under renewable energy (RE) policy, market participants in the electricity market need to make investment decisions on RE power generation. At the same time, market participants also need to address the specific issues associated with an investment in RE power generation, such as the investment cost of RE and the fixed cost recovery of networks. This study formulates frameworks for the evaluation of RE policies by modeling investment in RE and analyzing behavior and social surplus of the entire electricity market using two different methods: the real options approach and complementarity approach.

First, we develop models for the investment decision-making of power generation companies (GENCO) and transmission system operator (TSO) under vertical unbundling and uncertainty, applying the real options approach and game theory. We consider several scenarios in our analysis of the impact of each scenario on investment capacity, investment timing, and social surplus: (a) investment in RE with feed-in premium (FIP) policy; (b) investment in RE with reduction of RE installation cost; and (c) investment in non-renewable energy (NRE). Our results indicate that FIP and installation cost reduction of RE have different impacts on investment timing and capacity. In terms of social surplus, we present that FIP and installation cost reduction of RE can enhance social surplus more than the investment in NRE. Furthermore, when we compare FIP scenario and installation cost reduction of RE scenario, the magnitude of social surplus varies depending on the degree of uncertainty and the range of the installation cost of RE. In that lights, we suggest that appropriate RE policy formulation should take these factors into account. We also indicate that social surplus can be expanded without implementing FIP if the installation cost of RE is reduced sufficiently.

Next, we model the decision-making of electricity market participants in equilibrium, using the complementarity approach and taking into account prosumer investments in distributed energy resources (DERs); prosumer battery operations; fixed cost recovery of networks; electric power network; and pricing schemes. A prosumer is an entity that consumes electricity similar to consumers but also produces electricity similar to power producers. Our focus is on two pricing schemes, namely net metering and net billing, which allow prosumers to receive (or pay) compensation in different manners based on their electricity sales to the market through the grid. We examine the impact of decreased investment cost of RE on prosumer investment decisions, the transmission tariff, and social surplus under each pricing scheme. We find that the prosumer investment increases under both pricing schemes due to the decrease in the investment cost. Furthermore, in terms of social surplus, net metering and net billing obtain roughly the same level of social surplus when the investment cost of RE is high, while net billing obtains a larger social surplus because net metering is strongly affected by the decrease in consumer surplus when the investment cost of RE decreases sufficiently. We also analyze the case where prosumers operate battery storage. In this case, prosumer battery operation leads to larger prosumer investment. Moreover, the results of this case also indicate that net billing results in a larger social surplus than that net metering. Since results of social surplus are similar regardless of whether prosumers operate battery storage or not, our results are more robust. Overall, these results suggest that a larger social surplus can be obtained by net billing when the investment cost of RE decreases sufficiently.

This study develops RE power generation investment models that consider RE policies and electricity market systems, and analyze the impact of the policies and investment cost reductions of RE on the decision-making of market participants and on social surplus. Thereby, we propose frameworks for the evaluation of RE policies from the perspective of the entire electricity market, and provide suggestions for the formulation of future RE policies.

Acknowledgements

I am deeply grateful to my principal supervisor, Professor Makoto Tanaka, who gives me constructive comments and suggestions to support my research during the entire time of Ph.D. program in GRIPS. My dissertation would not have been possible without his continuous encouragement and persistent help.

I would also like to express my gratitude to Professors at GRIPS, especially my advisors, Professor Hisanori Nei and Michiko Iizuka, for their insightful comments and supports of my work.

My appreciation goes to Professor Ryuta Takashima of Tokyo University of Science for his expert assistance as an external evaluator of my dissertation.

I would like to acknowledge the support from all GRIPS staff for administrative support. For the foremost, I received generous support from Mr. Lawrie Hunter of the Center for Professional Communication in GRIPS for editing my dissertation. Last but not least, I would like to express special thankfulness to my family for always being there for me. I also would thank my parents and sisters for their profound support.

Table of Contents

List of Figures

List of Tables

List of Acronyms

DERs	Distributed energy resources
FIP	Feed-in premium
FIT	Feed-in tariff
GBM	Geometric Brownian motion
GENCO	Power generation companies
ISO	Independent system operator
KKT	Karush-Kuhn-Tucker
LNG	Liquefied natural gas
MILP	Mixed-integer linear programming
NG	Natural gas
NPV	Net present value
NRE	Non-renewable energy
PV	Photovoltaic
RE	Renewable energy
RPS	Renewable portfolio standard
TSO	Transmission system operator

Chapter 1

Introduction

1.1 General Background

1.1.1 Global warming and future energy sector challenges

Global warming is an environmental problem that need to be addressed as a global goal, as demonstrated in the Paris Agreement adopted at the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change (COP21) in 2015. The Paris Agreement stipulates that all ratifying countries, including major greenhouse gas emitters, must submit and update their reduction targets every five years in order to keep the global average temperature rise (from pre-industrial level) below two degrees Celsius. With that stipulation, that agreement established an international framework for addressing the global warming problem, involving developing countries and developed countries. To achieve that goal, it will be necessary to push forward with the decarbonization of energy and reduce global greenhouse gas emissions to virtually zero by the end of this century.

Energy demand is decreasing in OECD countries, and the share of OECD countries in global energy consumption has decreased to about 45 %. In the case of Japan, overall energy demand is decreasing due to the declining birthrate and the shrinking of the working population, with a further decrease in energy demand expected in the future (IEA, 2021). The reduction of energy demand in developed countries also can be considered the result of energy conservation thanks to more products and systems that consume energy more efficiently. Conversely, energy demand outside developed countries is increasing due to rapid economic and population growth in emerging countries, especially Asian nations such as India, China, and the ASEAN members. Compared to energy consumption in 2018, energy consumption in Asia is expected to increase by about 40% by 2040, and it will occupy the majority of global energy demand (IEA, 2019a). In total, future energy demand is predicted to increase due to continued global population growth and economic growth (IEA, 2019a). This future increase in energy demand could be a major factor contributing to carbon dioxide emissions. In the energy sector, which is essential for human activity and is a key to reducing carbon dioxide emissions, it is necessary to promote decarbonization in tandem with responses to the increase in energy demand.

In light of the above, the electricity sector's contribution is indispensable to the advance of decarbonization while accommodating increasing energy demand. Verbruggen and Lauber (2009) state that renewable energy (RE) power supply will be a critical factor for achievement of the goals of the Paris Agreement, and that the electricity sector needs to be converted to RE sources by 2050. In addition, the future progress of electrification in developing countries may contribute to the increase in electricity demand. In short, there is a need for investment in RE power generation that does not emit carbon dioxide and has rich resources for the achievement of decarbonization while still meeting the increasing energy and electricity demand.

1.1.2 Current status of and problems related to electricity market reform and RE policy

At the time of writing, RE policy development is underway worldwide, resulting in a rapid increase in investment in RE. Electricity generation from RE increased by nearly 7% between 2019 and 2020, with RE share of global electricity generation reaching 29%. It has been estimated that RE electricity generation will increase by an additional 8% or more in 2021 (IEA, 2019b). At the same time, electricity market reform, including deregulation and restructuring of regulatory designs, is being undertaken to ensure efficient operation of the electricity market. The past electricity markets were natural monopolies in countries with vertical integration and price control. However, in many countries electricity liberalization and vertical unbundling have been implemented as electricity market reforms aimed at the creation of more efficient markets. Electricity liberalization is expected to break away from the conventional natural monopolies and create an efficient electricity market through competition in terms of stable electricity supply, innovations in power generation methods, and downward pressure on electricity prices. Vertical unbundling, a mechanism involving the dismantling of traditional vertical integration, ensures fairness in the use of transmission lines. These electricity market reforms facilitate participation by new power generation companies and retail companies new to the electricity market. Nevertheless, continuous reform of the electricity market is essential for coping with the changes in market structure caused by the spread of RE (Conejo and Sioshansi, 2018). Thus, it is important to make appropriate changes to the future electricity market and formulate RE policies to attract further investment in RE. In the following, we consider several problems specific to investments in RE.

The first is the problem of the cost of RE investment. Unfortunately, the RE investment cost is relatively high compared to that of other power sources, hence it is difficult to recover the investment costs. For that reason, many RE policies to date have been aimed at solving this problem. At the same time, there has been a recent increase in RE investment, driven by reduction of RE investment costs: now the costs associated with RE are expected to continue to decrease (IRENA, 2021). Although the problem of RE investment costs is gradually being solved by current RE policies and investment cost reduction, there is still a need for system and policy support because the approach to RE cost reduction varies across countries and regions.

Second, problems related to networks, especially the problem of recovery of fixed costs related to networks, have also appeared. For example, in Germany, where

RE investment has been progressing rapidly, delays in investment in networks have caused a shortage of transmission capacity between the north and south regions, which makes it difficult to achieve smooth power supply (Schermeyer et al., 2018; Kunz, 2013). Moreover, the problem of fixed cost recovery of networks is closely related to the increase in distributed energy resources (DERs), which are small-scale power generation facilities using RE such as photovoltics (PVs). The resource of investment in and maintenance of networks is mainly collected from consumers based on their electricity usage. However, as the number of DERs increases, consumers without DERs will bear a large share of the fixed cost recovery of networks, since consumers with DERs consume electricity from their DERs and minimize the use of network. Furthermore, consumers without DERs will install DERs to avoid the related hefty burden, creating a spiral that will increase the burden on consumers without DERs, as a result of further decrease in the use of network. This problem is referred to as the death spiral problem (Castaneda et al., 2017).

In order to address the above problems with further RE investment, appropriate tariff and regulatory designs are required. In that light, addressing those problems is an inevitable part of electricity market reform and the formulation of RE policy.

1.1.3 Current policy for further promotion of RE power generation

For further RE investment, RE policies are being implemented with consideration of the problems mentioned in Section 1.1.2. However, it is not sufficient to implement the same RE policy in every country. Each country must change and update its policies in an ongoing manner, in light of its electricity market, the type of RE source, and the status of RE diffusion in the country. In this study, we examine some instances of RE policy, feed-in premium (FIP); net metering; and net billing, and discuss future reconfigurations of those policies.

We begin with a discussion of feed-in tariff (FIT) and FIP as the most representative RE policies, recognized for their significant contribution to the promotion of RE investment (Schallenberg-Rodriguez, 2017). FIT policy has been observed to increase the predictability of investment cost recovery and to encourage RE investment by purchasing RE electricity at a fixed price set higher than the market price in long term. On the other hand, it is necessary to continuously change the level of the fixed price for FIT, in anticipation of a decline in the cost of RE investment since FIT ensures incentives for RE investment by means of trading exeptions in the electricity market. In addition, when the RE share of power generation increases under FIT, market price fluctuations increase, resulting from changes in RE electricity generation practice. Therefore, RE policy should be varied in accordance with the degree of impact of RE generation on the electricity market (Winkler et al., 2016). Thus, given the likelihood of future increases in the degree of RE penetration, and the financial burden of implementation of FIT, appropriate policy updates may be necessary to ensure incentives for RE investment as RE power generation penetrates the market. For this reason, formulation of new RE policies is under discussion by each country. The FIP system, currently being introduced mainly in the EU, allows electricity generated from RE sources to (a) be traded in the electricity market in the same manner as other power sources, and (b) be sold at a premium (Schallenberg-Rodriguez and Haas, 2012). FIP policy is expected to enable the integration of RE power generation into the electricity market while ensuring incentives for investment.

The other two prominent policy systems, net metering and net billing, allow consumers with DERs to receive compensation based on their electricity sales to the market via power grid, and are expected to increase investment in DERs. The increase in DERs contributes to the spread of RE and plays a vital role in risk diversification and resilience enhancement related to energy supply and demand. Especially in Japan, where the Great East Japan Earthquake exposed the vulnerability of the conventional electricity system, DERs will play an important role in the future. Net metering is a system that allows consumers who own DERs to offset their electricity consumption and electricity sales at the same price (Prol and Steininger, 2017). The net metering scheme, first introduced in the U.S. in the 1980s, is now in use in almost every state in the U.S. and in other countries with abundant solar resources, e.g., Spain (Dufo-Lopez and Bernal-Augstín, 2015). Although it has been found that the net metering scheme encourages investment in DERs, there is now discussion of further revisions to the system, such as shifting to net billing, given the probability that it could give rise to the death spiral problem (Chhabra and Lamare, 2021). Net billing, a system that allows consumers who own DERs to offset their electricity consumption and electricity sales at different prices, generally sets the sale price of electricity lower than that for electricity consumption (IRENA, 2019). The primary difference between net metering and net billing is in the way how consumers with DERs are charged when selling excess electricity to the grid.

In this study, we examine policy-based means of promotion of RE investment in tandem with the addressing of two problems, RE investment cost and fixed cost recovery of networks. In particular, we focus on FIP, net metering, and net billing and discuss how to re-formulation of these policies in the future.

1.2 Literature review

1.2.1 Electricity market reform and RE policy

Due to the increase in RE implementation, further adjustments in and research on the electricity market are essential. Based on an examination of electricity market reform over the last 30 years, Conejo and Sioshansi (2018) argued that it is necessary to conduct research on a number of issues for efficient operation of the future electricity market, considering the changes in basic electricity market structure. Blazqueza et al. (2018) stated that increasing the share of RE electricity generation and encouraging decarbonization are the primary means of achieving the goals set out in the Paris Agreement. They argued that RE diffusion using current electricity market designs might distort electricity prices and slow down the introduction of RE. They also claimed that introducing FIP and coexistence with fossil fuels are necessary for continued acquisition of the share of RE. Finally, they pointed out an incompatibility between electricity liberalization and RE policy, and argued that there is a need to reconsider the regulatory designs of the electricity market. Peng and Poudineh (2019) noted that ongoing investment in RE and the increasing share of RE generation have caused distortions in the electricity market, even though the previous electricity market reform was aimed at removing RE investment risk. However, the EU aims to be getting 50 % of its total electricity supply from RE by 2030; and to be fully decarbonized by 2050. They pointed to a need to rethink the future electricity market design in order to sustain further investment in RE. In particular, they stated that there is room for market reform to further decarbonization in terms of support mechanisms for RE; grid regulation; long-term energy resource adequacy; and short-term operational security of the electricity market. Jamsb and Pollitt (2005) indicated the achievements and future challenges of the UK electricity market reform. RE policies have led to achieving targets for RE electricity generation; at the same time, that achievement revealed a need for further innovation in RE policies. They mentioned that RE policy represented by FIT contributes significantly to the predictability of RE investment, while it is challenging to balance economic efficiency and diffusion of RE. They concluded that the relationship between future electricity market reform and RE policy would be an essential issue.

There are also studies on the problems caused by past electricity market reforms. For example, Joskow (2008) demonstrated that electricity market reform in many countries has encouraged investment in new power generation facilities and improved power generation performance, using empirical analysis. They also mentioned that the electricity crisis, e.g., the California electricity crisis and the electricity crises in Brazil and Chile, represents imperfections of electricity market reform. Lee et al. (2019) applied a regression model to analyze the impact of electricity market reform, such as vertical unbundling and regulation, on investment in power generation facilities for 27 of the OCED countries. They demonstrated that electricity liberalization and vertical unbundling positively affect the generation capacity and the reserve ratio, while some regulations negatively affect investment in power generation facilities. Joskow (2005) examined the efficient use of the power grid. They indicated that U.S. transmission policies have stalled investment in new networks, and led to network congestion due to intensive use of existing networks.

There has been no perfect electricity market reform to this day. Further research on the relation between RE policy and electricity market reform is necessary, given the impact of future RE energy generation.

1.2.2 Evaluation of FIT and FIP to date and the way forward

There are many studies that showed the achievements of FIT. Nicolini and Tavoni (2017) examined the effectiveness of RE policies using examples of five EU countries since 2000. They mentioned that FIT is positively correlated with increases in RE investment and RE electricity generation, and is effective in the short and long terms. González and Lacal-Arántegui (2016) indicated that FIT and FIP have a positive impact on the investment in wind power. They also argued that RE policies need to update continuously.

There are also many studies on the relation between the electricity market and RE policy. Couture and Gagnon (2010) mentioned that there is a growing interest in future policy formulation that incorporates the advantages of FIT and FIP, based on the case study in Spain. They found that FIT is an effective policy for increasing RE investment; however, a shift in policy should be made in order to integrate RE into existing electricity market as the market share of RE increases. In particular, they concluded that FIP could be an effective means of integrating RE into the market while ensuring power generation incentives. Schallenberg-Rodriguez and Haas (2012) conducted a performance assessment for FIT and FIP have been implemented in Spain. They stated that those policies have positive results for RE investment. They also proposed introducing a new form of FIP (FIP with upper bound) to address the overcompensation by the current FIP. Wagner (2017) analyzed the impact of RE power generation on networks. They examined the impact of FIT and FIP on investment in networks and the location choice of RE generation facilities. They argued that a need for appropriate RE policy formulation and coordination of investment between transmission and new power facilities, under electricity liberalization and vertical unbundling. Especially, they pointed investors under FIT and FIP might not invest in the best place for the electricity market, resulting in inefficiencies in an investment of network.

Several studies also mentioned the importance of the future conversion of RE policy due to an increase in RE. Kitzing (2012) investigated RE policies that have been implemented in the EU over the past decade. They presented a tendency to combine several RE policies rather than a single policy in the EU, mainly FIT and FIP. They concluded that combining multiple policies might be important for the future efficient introduction of RE. Winkler (2016) examined the impact of an increase in the share of RE in the electricity market. They mentioned that an increase in RE power generation results in lower electricity prices and increased price volatility, which leads to reducing the operation rate of power generation with fossil fuels. In that situation, power generation with fossil fuels cannot recover fixed costs for investment in new power generation facilities and maintenance of existing power generation facilities, since that power generator cannot earn enough income by electricity sales. That problem of fixed cost recovery of power generation facilities is known as the missing money problem. They also analyzed the impact of various RE policies on the electricity market based on the case study of Germany. They conclude that FIP could be a compromise policy for further RE investment with mitigating impact of RE investment on the electricity market.

Many studies suggested that FIT has a considerable effect on the spread of RE in many countries. However, studies also showed that, in anticipation of future increases in RE, there is a need to shift to other policies, mainly FIP.

1.2.3 Pricing schemes: net metering and net billing

This study includes net metering and net billing as RE policy. Net metering is a widespread system mainly in the U. S., where 99% of all PVs in the US adopted net metering in 2014. Although FIT, FIP, and tradable green certificates are mainly adopted in the EU, net metering and net billing are adopted in some countries, e.g., Italy and the Czech Republic. Currently, many countries are considering the implementation of net metering and net billing in order to promote investment in PVs with phasing out subsidies (IRENA, 2017). Wittmayer (2021) noted that prosumers, who consume electricity similar to consumers but also produce electricity similar to power producers, will be essential for the future spread of RE. They also indicated that net metering and net billing will be critical policies in the future because prosumer electricity generation in all EU member states could account for more than 20% of electricity demand in 2050. Poullikkas et al. (2013) surveyed net metering schemes implemented in various countries in various ways. Christoforidis et al. (2016) suggested net metering becomes one alternative to FIT because FIT has been significantly scaled back or eliminated in recent years. They conducted a case study of net metering in Greece to propose an evaluating methodology for RE policy. Although adoption of net metering is limited in EU countries at present, there is a lot of interest in net metering and net billing as alternative options to provide future investment opportunities for small-scale PV in Mediterranean countries with high PV potential. Therefore, these policies are expected to play an active role in the coming years.

There are also some discussions related to an increase in DERs due to net metering. Castaneda et al. (2017) applied a system dynamics model to assess the impact of PV on the electricity market under net metering, based on the case study of Colombia. They showed that net metering might cause a death spiral problem by increasing consumers' PV capacity and network tariff. They also indicated that net metering might hinder investment in networks. Finally, they suggested that net billing becomes one of the solutions for those problems. Watts et al. (2015) conducted the performance analysis of the impact of net metering and net billing on the productivity and economics of PV. They mentioned that net billing could be an advantageous pricing scheme when consumers install PVs with a small capacity within their own electricity consumption. Moreover, they revealed that those pricing schemes are affected by differences in the retail electricity price and solar radiation, leading to significant changes in PV performance and the payback period of the investment cost. IRENA (2019) reported that Italy, Portugal, and the U.S. in Arizona and New York are gradually shifting from net metering to net billing.

For further investment in DER, we need to consider the implementation of several pricing schemes as RE policy. In this study, we focus on net-metalling and net-billing and discuss the future formulation of those..

1.2.4 Modeling methods for investment in RE power generation

This study provides analytical frameworks by modeling two different methods: the real options approach and the complementarity approach. In both methods, we construct models that can analyze social surplus and decisions of market participants, considering the RE investment under RE policy.

We first construct a model for investment decisions using the real options approach. The real options approach is a method that enables us to analyze investment decisions under uncertainty (Dixit and Pyndyck, 1994). There are many real options models regarding RE investment decision-making since the electricity market involves many uncertainties, such as electricity demand; power generation; and fuel and electricity prices. For example, Boomsma and Linnerud (2015) modeled investment decisions of RE generation projects under FIT and FIP with consideration of the price and subsidy uncertainty. They focused their analysis on the investment timing. Ritzenhofen and Spinler (2016) applied the real options approach to RE generation projects to analyze the relationship between the level of FIT price and investment decisions of RE under conditions of continuous review of RE policy. Reuter et al. (2012) applied the real options approach to examine investment decision-making of new power generation facilities and choice of technologies, considering an increase in the number of competitors and the electricity price uncertainty. On the other hand, the real options approach also have been applied to investment decisions of transmission side. Sereno and Efthimiadis (2018) examined the investment problem of bilateral power grids under electricity demand uncertainty, using the real options approach. They focused on the threshold and investment capacity for analysis. As described above, the real options approach is an effective modeling method for decision-making under uncertainty and RE policy. However, those previous studies have applied the real options approach to either decision of power generation side or transmission side, focusing mainly on the investment timing and capacity for analysis. In this study, we apply the real options approach to construct models that simultaneously consider the investment decision-making of power generation companies (GENCO) and transmission system operator (TSO) under RE policy and uncertainty. Furthermore, our analytical framework enables us to examine social surplus and decisions regarding all market participants, and evaluate RE policy from the perspective of the entire electricity market.

We also build a model that includes prosumer investments in DERs using the complementarity approach. There are several analyses focused on prosumer investment. Kappner et al. (2019) applied net present value (NPV) to the economic evaluation of prosumer for various combinations of PV and battery capacity. Calvillo et al. (2016) analyzed prosumer investment decisions by modeling the profit maximization problem for optimal operation planning of the aggregated DERs, using mixed-integer linear programming (MILP). Castellini et al. (2021) examined prosumer investment in terms of the optimal PV size and investment threshold, using the real options approach. As shown above, several modeling frameworks for prosumer investment decisions are constructed. However, few studies modeled the entire electricity market decision-making, including prosumers. Ramyar et al. (2020) constructed an equilibrium model regarding all market participants' decisions, including prosumers; consumers; producers; and grid operator, using the complementarity approach. However, their study did not consider prosumer investments, battery operations, and net metering and net billing, which are the focus of this study. We examine market equilibrium in terms of decision-making of all market participants and social surplus with consideration of prosumer investments; pricing schemes; electric power networks; and transmission cost recovery.

Accordingly, this study develops RE investment models using the real options approach and complementarity approach, respectively. Both models enable us to evaluate RE policy in terms of social surplus and decisions of market participants by covering the entire electricity market.

1.3 Results and contribution

To achieve decarbonization, RE policy formulation for investment in RE is becoming increasingly important. Since each RE policy has its advantages and disadvantages, it is necessary to formulate RE policy suitable to the degree of RE diffusion and investment cost. Participants in the electricity market face important decision-making about matters that they have not experienced before, such as investment in RE and fixed cost recovery of networks, in the context of continuous updating of RE policy and electricity market. The aim of this study is to evaluate RE policy by conducting two analyses (one using the real options approach; the other using the complementarity approach) of market participant RE investment decisions and social surplus. In both analyses, we consider the decision-making process of all market participants for the evaluation of RE policy from perspective of the entire electricity market.

First, we analyze the decision-making of GENCO and TSO related to investment in generation and transmission capacity with different objectives under vertical unbundling. We combine a real options approach and game theory for our analysis, and compare the impact of each FIP and installation cost reduction of RE in terms of investment timing, capacity, and social surplus. We observe that FIP and installation cost reduction of RE have different effects on each decision regarding investment timing and capacity. We also argue that appropriate policy formulation is required since the magnitude of social surplus under the FIP and installation cost reduction of RE varies depending on the degree of uncertainty. Finally, this analysis suggests that if the installation cost of RE decreases sufficiently, it may be possible to obtain a greater social surplus without FIP.

Next, we construct an analytical framework for decision-making by electricity market participants in equilibrium, by modeling prosumer investments in DERs;

battery operations; electric power networks; and pricing schemes such as net metering and net billing, using the complementarity approach. We demonstrate that prosumer investment in PVs under both pricing schemes increases as the investment cost of PV decreases. In terms of total social surplus, both net metering and net billing yield roughly the same total social surplus within the range of the high investment cost of PV. However, net billing yields a greater total social surplus than net metering when the investment cost of PV is reduced, since net metering is affected by a sharp decrease in the consumer surplus. Besides, from the case where prosumers operate battery storage presents that prosumer battery operation raises prosumer investment in PVs under both pricing schemes. Furthermore, net billing obtains a larger total social surplus than net metering, in a manner similar to that in the case without prosumer battery operation. Hence, we demonstrate that net billing can generate a large total social surplus both with and without prosumer battery operation, and suggest that it could be a better regulatory scheme.

This study first models the decision-making of GENCO and TSO with their different objectives, using the real options approach and game theory. Based on that modeling, we propose a framework for analyzing investment timing, capacity, and social surplus while considering FIP and installation cost reduction of RE. Next, we propose a framework for analyzing the decision-making of market participants and social surplus in equilibrium by modeling the electric power network; pricing schemes; transmission cost recovery; prosumer investments; and battery operations, using the complementarity approach. In both analyses, we model investment decision-making in RE with consideration of the entire electricity market and propose frameworks for analyzing investment decisions and social surplus. Our contribution is an approach to the evaluation of RE policy from the perspective of the entire electricity market, and the derivation of suggestions for future RE policy formulation.

1.4 Organization of this study

This study is organized as follows: In Chapter 2, we model the decision-making of the GENCO and TSO using the real options approach and analyze the results focusing on investment timing, capacity, and social surplus. In Chapter 3, we model the framework of the complementarity approach to analyze prosumer investment decisions and social surplus and make suggestions. Chapter 4 summarizes the results and policy implications of these analyses as a conclusion. The overview of this study is illustrated in Fig. 1.1.

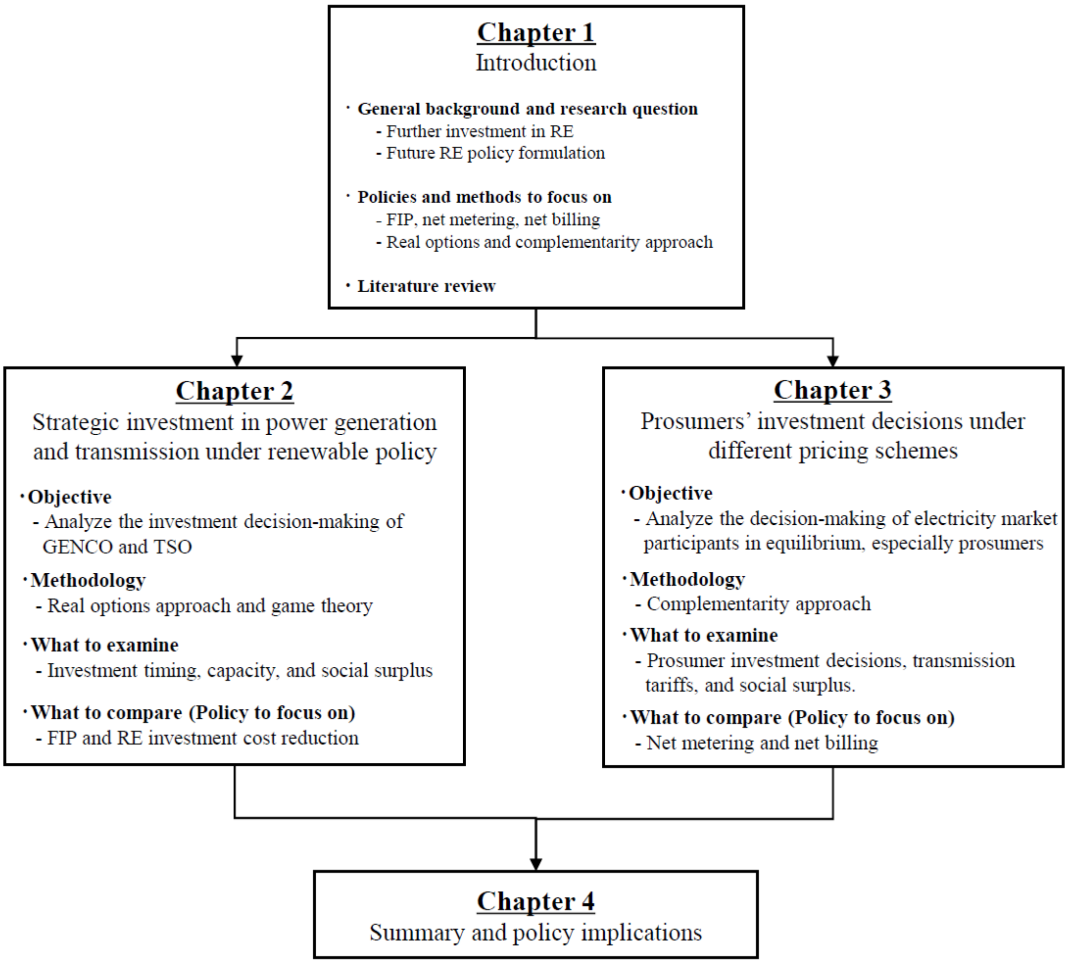

Figure 1.1: Overview of this study

Chapter 2

Strategic investment in power generation and transmission under renewable policy: A game theoretic real options analysis

2.1 Introduction

As seen in the Paris Agreement, global warming is a significant issue since it causes many problems such as climate change. The energy sector, especially the electric power sector, accounts for most of the greenhouse gas emissions that cause global warming due to their use of fossil fuels for power generation. Therefore, it is expected to contribute to solving global warming to shift from fossil fuel power generation to RE power generation with a lesser impact on the environment. Many countries have already begun to take steps to reduce the installation costs of RE, develop power grids, and rationalize policy and institutional design for the spread of RE use. In particular, the implementation of renewable portfolio standard (RPS), FIT, FIP, and the installation cost reduction of RE through technological innovation have promoted further investment in RE (Cheng et al., 2017).

Since the 1990s, the electricity market reforms have been carried out starting in Europe and the United States. The liberalization of the electric power industry has been implemented to create efficient markets. Subsequently, the vertical integration system, in which all processes from power generation to transmission are integrated and managed by a single entity, has been unbundled to strengthen fairness and independence in the use of transmission lines. In this way, not only on the power generation side but also on the transmission side, further electricity market reforms are underway to stimulate competition and make the electricity market more efficient (Newbery, 2002; Künneke and Fens, 2007).

Under an unbundled system, GENCO and TSO need to make independent and individual investment decisions to expand transmission and power generation facilities, taking into account the technological innovations, policies for the promotion of RE, and regulatory instruments to mitigate the environmental impact of CO_2 (e.g., environmental tax based on damage costs). In addition, we need to pay attention to the uncertainties represented by electricity demand, price, and fuel costs when making investment decisions in the electricity market. This study assumes a situation where GENCO and TSO make decisions considering each other's behavior under a vertical unbundling. We apply game theory and the real options approach framework to this situation to analyze both player's decision-making under uncertainty.

The real options approach has been applied to decision-making problems in many fields (Dixit and Pyndick, 1994). Many decision-making problems in the electricity markets also have been solved by the real options approach due to the need to deal with various uncertainties. Pringles et al. (2014) used the real options approach to evaluate the investment performance of the transmission system, and showed transmission projects that properly include flexibility in investment, such as options to delay, have a higher project value. Fleten et al. (2011) analyzed investment decisions for transmission capacity expansion between Norway and Germany, using a real options approach, taking into account the effect of the electricity price difference between the two regions. Likewise, Sereno and Efthimiadis (2018) also analyzed the investment problem of the transmission line between two neighboring countries using a real options approach under capacity constraints and incentive schemes. On the other hand, there are also many studies of the GENCO side using the real options approach. Bøckman et al. (2008) examined the Norwegian case study of the investment project for small hydropowers to evaluate the optimal investment timing and capacity under uncertainty. The study revealed that applying the real options approach allows for optimal decision-making compared to net present value. However, many analyses using the real options approach have focused on the decision-making of either only GENCO or only TSO.

Moreover, many studies on decision-making problems in the electricity market consider RE policies since the contribution of the electric power sector is essential to achieve decarbonization. Cheng et al. (2017) used the real options approach to analyze the delay option and optimal investment timing for PV projects in China under environmental policies. They found that the government might encourage investment in PV through FIT and other RE policies. Similarly, Boomsma et al. (2012), Kozlova et al. (2019), and Barbosa et al. (2018) investigated the investment timing and capacity choice of RE generation projects under environmental policies such as FIT and FIP. Kitzing et al. (2017) reported that FIT, FIP, and tradable green certificates provide different investment incentives for investment timing and capacity choice, in the investment of offshore wind power by applying the real options approach under capacity constraints. A study that combines the real options approach and game theory was carried out by Zeng and Chen (2019), who analyzed the optimal concession period of PV projects with the FIP and subsidy for installation cost of RE in China, under the government and private sector game. Although there are many studies for decision-making problems in the electricity market, to the best of our knowledge, no study has applied both the real options approach and game theory to decision-making for capacity expansion and investment timing of GENCO and TSO under environmental policies, and analyzed them simultaneously in terms of social surplus.

Using the real options approach and game theory, this study aims to analyze investment decision-making for GENCO's and TSO's capacity expansion under vertical unbundling, focusing on social surplus, investment timing, and capacity. Besides we set scenarios considering the case in which GENCO and TSO invest in RE power generation: the scenario with FIP for promoting RE and the scenario with the installation cost reduction of RE through technological innovation. We have two primary findings. First, we demonstrate the difference in the impact of FIP and installation cost reduction of RE on optimal investment timing and capacity expansion. The FIP delays investment timing, and encourages investment in a larger capacity, while the installation cost reduction of RE speeds up the investment timing and encourages investment in a relatively smaller capacity. Second, we show that the magnitude of social surplus in each scenario varies depending on the degree of uncertainty. Therefore, it is necessary to make appropriate decisions depending on the degree of uncertainty. Furthermore, if the installation cost of RE is reduced to the same level as the current installation cost of thermal power generation due to further technological innovation, this scenario achieves a larger social surplus than the implementation of FIP in all degrees of uncertainty.

The rest of this study is organized as follows. Section 2.2 defines scenarios, settings, and formulates the models of each decision-maker. Section 2.3 conducts the qualitative analysis regarding the parameters that affect each decision-maker. Section 2.4 conducts numerical analysis for the best response function, investment timing, capacity expansion, and social surplus. Finally, we present the conclusion of the analysis in Section 2.5.

2.2 Model

2.2.1 Scenario and setup

This study sets up the electricity market that consists of one GENCO and one TSO under vertical unbundling. We model GENCO's and TSO's decision-making problems with different objectives. The GENCO aims to maximize its profit from electricity sales as aggregated power generation facilities, while the TSO aims to maximize the social surplus under regulations as a public institution. To compare the investment in non-renewable energy (NRE) with investment in RE, we consider two scenarios of capacity expansion - by NRE using liquefied natural gas[1] (LNG) (L-L scenario) and by RE using wind power (L-W scenario). We set LNG as NRE because it will be one of the main NRE sources for the transition toward decarbonization. Meanwhile, we set wind power as RE because we assume a case in which a region with abundant wind energy resources is connected by a transmission line to remote demand centers, e.g., the north and south regions (Tohoku and Tokyo areas) of Japan or the north and south regions of Germany. The L-W scenario is further divided into two scenarios, one with subsidies through FIP (L-W-FIP scenario) and the other with a reduction in the installation costs of RE (L-W-Cost scenario). Thus, we have three scenarios: L-L, L-W-FIP, and L-W-Cost.

In all scenarios, the GENCO has an initial power generation capacity of q_0 (> 0) using LNG. Similarly, the TSO has an initial transmission capacity of q_0. In the L-L scenario, the generation capacity of LNG is added to the initial capacity q_0 to become q_1 (> 0). In the L-W scenario, the capacity to generate wind power is added to the initial capacity q_0 to become q_1. After reaching the investment threshold of x, the TSO expands the transmission capacity from q_0 to q_1 according to the capacity determined by the GENCO. On the other hand, the GENCO invests in expanding its generation capacity from q_0 to q_1, in line with the TSO's investment threshold. The capacity q_1 is obtained as a solution to the GENCO's profit maximization. The investment threshold x is calculated from the TSO's social surplus maximization using a value-matching condition and a smooth-pasting condition which is described later.

We assume that the TSO invests as soon as the investment threshold is reached, denoting investment threshold as the investment timing in this study. Similarly, we

[1] Our model can also be applied to the case for natural gas (NG) with pipelines as a NRE source.

assume that the GENCO takes the TSO's investment threshold as its own investment timing, and invests as soon as the investment threshold is reached. Since the construction of a transmission line takes a considerable amount of time and costs, it is realistic to consider a setting in which the TSO decides the investment timing considering generation capacity determined by the GENCO. Note that a larger investment threshold represents a delay in the investment timing because the TSO waits more for its investment.

Our setup can be regarded as a game between two players (Künneke and Fens, 2007; Pollitt, 2008). That is, GENCO determines the optimal capacity considering the TSO's investment timing, while as a public institution the TSO determines the optimal investment timing to expand transmission capacity, taking into account GENCO's capacity for expansion.

P_t is the electricity price at continuous time t and is defined as an inverse demand function as follows:

$$P_t(Q_{i,k}) = X_t(1 - \eta Q_{i,k}), \tag{2.1}$$

where i represents the state of the electricity market, $i = 0$ is the state before investment, and $i = 1$ is the state after investment. k represents the power generation technology, which distinguishes between wind power generation ($k = W$) and LNG power generation ($k = L$). $Q_{i,k}$ is the amount of electricity in the market, and η (> 0) is the coefficient of the inverse demand function. We also assume that $\eta < \frac{1}{Q_{i,k}}$ to keep the electricity price positive. Additionally, the uncertainty X_t represents the demand shock of the electricity market in t and follows a geometric Brownian motion (GBM). The GBM, which allows us to represent exogenous shocks in continuous time, is defined as follows:

$$dX_t = \mu X_t dt + \sigma X_t dW_t, X_0 = x \tag{2.2}$$

μ is the expected rate of change for demand shocks, σ is the volatility, W_t is the standard Brownian motion, and X_0 is the initial value. Lastly, $Q_{i,k}$ is defined as follows:

$$Q_{i,k} = \begin{cases} Q_{0,k} = Q_{0,L} = q_0 \alpha_L H, & (i = 0) \\ Q_{1,k} = q_0 \alpha_L H + (q_1 - q_0)\alpha_k H & (i = 1) \end{cases} \tag{2.3}$$

α_k represents the capacity factor of each power generation technology with the range $0 \leq \alpha_k \leq 1$. H is the annual operating hours of the power generation facilities, i.e., $H = 8,760$.

2.2.2 Optimal capacity for GENCO

In this subsection, we consider the value of the GENCO after the investment in capacity expansion. Given the TSO's investment timing x (> 0), the GENCO pays costs,[2] and expands its generation capacity to maximize profits from electricity sales. The value of the GENCO is represented as follows:

$$\begin{aligned} V_1(x, q_1) &= \mathbb{E}\left[\int_0^\infty e^{-\rho t}(Q_{1,k}P_t - G_{1,k})dt\right] - \xi_k(q_1 - q_0) \\ &= \frac{(1 - \eta Q_{1,k})Q_{1,k}x}{\rho - \mu} - \frac{G_{1,k}}{\rho} - \xi_k(q_1 - q_0) \end{aligned} \tag{2.4}$$

$$G_{1,k} = q_0 \alpha_L H(C_L + \lambda_L N) + (q_1 - q_0)\alpha_k H(C_k - F_k + \lambda_k N) \tag{2.5}$$

[2] In this study, we assume a "super-shallow" scheme in which the GENCO bears only the installation cost of the power generation system and does not bear the installation cost of new transmission lines to connect to the power grid or the cost of augmenting for existing transmission lines. The other is the "shallow" scheme, in which the GENCO bears the installation cost of power generation system and new transmission lines to connect to the grid, but not the cost of augmenting for existing transmission lines, and the "deep" scheme, in which the GENCO bears the installation cost of the power generation system, transmission lines, and the cost of augmenting for existing transmission lines.

Here, ρ is the discount rate, and e is the base of the natural logarithm. Based on the basic assumptions of the real options approach, we also assume $\rho > \mu$. Future profits are discounted by $e^{-\rho t}$ under a continuous-time framework. Besides, C_k and ξ_k represent the variable cost per kWh and the installation cost per kW for each power generation system, respectively. $G_{i,k}$ is the sum of the variable cost, the environmental tax, and subsidy from FIP. The CO_2 emission from NRE is calculated using CO_2 emission factor λ_k, where we assume $\lambda_L > 0$ and $\lambda_W = 0$. N is the environmental tax per ton of CO_2 emission, which is introduced as a regulatory instrument to reduce the GENCO's emissions. F_k represents the FIP level, that is the fixed premium paid for each kWh of electricity generated by RE, where we assume $F_L = 0$ and $F_W > 0$. The first-order condition for the optimal capacity of the GENCO is expressed as follows:

$$\frac{\partial V_1(x, q_1)}{\partial q_1} = 0 \tag{2.6}$$

By solving Eq. (2.6), the optimal capacity of the GENCO after the investment, q_1, is obtained as:

$$q_1 = \frac{\rho \alpha_k H x - (\rho - \mu)\alpha_k H (C_k - F_k + \lambda_k N) - \rho(\rho - \mu)\xi_k}{2\rho\eta\alpha_k^2 H^2 x} - \frac{q_0(\alpha_L - \alpha_k)}{\alpha_k} \tag{2.7}$$

The optimal capacity q_1 of the GENCO is a function of the investment timing x of TSO. That is $q_1(x)$ can be regarded as the best response function of the GENCO in game theory.

2.2.3 Optimal investment timing of TSO

Next, we consider the invesetment decision-making of the TSO. We focus on the role of the TSO as a decision-maker on transmission facilities in the long run. The TSO expands the transmission capacity from q_0 to q_1 at the investment timing x for maximizing the social surplus, where q_1 is determined by the GENCO. First, the social surplus after the investment given q_1 is expressed as follows:

$$\begin{aligned} S_1(x, q_1) &= \mathbb{E}\left[\int_0^{\infty} e^{-\rho t}\left(\int_0^{Q_{1,k}} P_t(Q)dQ - B_{1,k}\right) dt\right] - (\xi_k + \gamma)(q_1 - q_0) \\ &= \frac{(2 - \eta Q_{1,k})Q_{1,k}x}{2(\rho - \mu)} - \frac{B_{1,k}}{\rho} - (\xi_k + \gamma)(q_1 - q_0) \end{aligned} \tag{2.8}$$

$$B_{1,k} = q_0\alpha_L H(C_L + \lambda_L M) + (q_1 - q_0)\alpha_k H(C_k + \lambda_k M) \tag{2.9}$$

Here, $B_{i,k}$ is the sum of the variable cost and the damage cost for electricity. The damage cost M per unit is the environmental impact of CO_2 per ton emitted from NRE. By considering the damage cost, the TSO controls CO_2 emissions to mitigate negative impacts on the environment. For a more detailed explanation, please refer to Tol (1995) and Krewitt et al. (1999). We also assume that the environmental tax is collected from the GENCO, and its tax revenue returns to the consumers will be in a lump sum. For this reason, the environmental tax is offset in social surplus, since it is a transfer between the GENCO (producers) and consumers. Similarly, the FIP is collected from the consumers in a lump sum and returns to the GENCO. FIP is also offset in social surplus. Besides, the TSO bears the installation cost of the transmission line per kW, γ. The following equation expresses the social surplus of TSO before the investment.

$$\begin{aligned} S_0(x) &= ax^{\beta_1} + \mathbb{E}\left[\int_0^{\infty} e^{-\rho t}\left(\int_0^{Q_0} P_t(Q)dQ - B_{0,k}\right) dt\right] \\ &= ax^{\beta_1} + \frac{(2 - \eta Q_{0,L})Q_{0,L}x}{2(\rho - \mu)} - \frac{B_{0,k}}{\rho} \end{aligned} \tag{2.10}$$

$$B_{0,k} = B_{0,L} = q_0\alpha_L H(C_L + \lambda_L M) \tag{2.11}$$

The first term ax^{β_1} in Eq. (2.10) is the option value calculated from the optimal stopping problem with the GBM as the state variable. a is the coefficient of the option value, and β_1 >1 is the positive root of the characteristic equation satisfied by the second-order (inhomogeneous) differential equation. For a general description of the optimal stopping problem with GBM as the state variable (real options approach) and the derivation of the Eq. (2.10), see Appendices A.1, A.2 and Dixit and Pindyck (1994). The x and a are derived from the following conditions:

$$\begin{cases} S_0(x) = S_1(x, q_1) \\ \frac{dS_0(x)}{dx} = \frac{\partial S_1(x,q_1)}{\partial x} \end{cases} \tag{2.12}$$

The first line is the value-matching condition that represents the continuity between the value of before and after investment. The second line is the smooth-pasting condition that represents optimality. The second-order (inhomogeneous) differential equation needs to satisfy these two conditions. These conditions give the optimal investment timing x as follows:

$$x = \frac{\beta_1}{\beta_1 - 1} \frac{\rho - \mu}{g_1 - g_0} \left(\frac{B_{1,k} - B_{0,k}}{\rho} + (\xi_k + \gamma)(q_1 - q_0) \right) \tag{2.13}$$

$$g_i = (1 - \frac{\eta}{2} Q_{i,k}) Q_{i,k}$$

$x(q_1)$ can be regarded as the best response function of the TSO since the investment timing is determined after considering the capacity q_1. Finally, the option value coefficient is calculated using TSO's optimal investment timing x as follows:

$$a = \frac{(g_1 - g_0)x^{1-\beta_1}}{\beta_1(\rho - \mu)} \tag{2.14}$$

2.2.4 Equilibrium of investment timing and capacity

As discussed in the previous subsections, the GENCO determines capacity q_1 based on the given investment timing x, while the TSO determines investment timing x based on the given capacity q_1. Let (x^*, q_1^*) denote the equilibrium of investment timing and capacity. Then, (x^*, q_1^*) satisfy the following three conditions simultaneously from Eqs. (2.12) and (2.6).

$$\begin{cases} S_0(x^*) = S_1(x^*, q_1^*) \\ \frac{dS_0(x^*)}{dx^*} = \frac{\partial S_1(x^*, q_1^*)}{\partial x^*} \\ \frac{\partial V_1(x^*, q_1^*)}{\partial q_1^*} = 0 \end{cases} \tag{2.15}$$

In other words, (x^*, q_1^*) satisfy the following conditions from Eqs. (2.13) and (2.7).

$$x^* = \frac{\beta_1}{\beta_1 - 1} \frac{\rho - \mu}{g_1 - g_0} \left(\frac{B_{1,k} - B_{0,k}}{\rho} + (\xi_k + \gamma)(q_1^* - q_0) \right) \tag{2.16}$$

$$q_1^* = \frac{\rho \alpha_k H x^* - (\rho - \mu)\alpha_k H (C_k - F_k + \lambda_k N) - \rho(\rho - \mu)\xi_k}{2\rho\eta\alpha_k^2 h^2 x^*} - \frac{q_0(\alpha_L - \alpha_k)}{\alpha_k} \tag{2.17}$$

Since x^* and q_1^* are the best responses to each other, it can be regarded as Nash equilibrium in game theory.

2.3 Qualitative analysis

In this section, we present the qualitative analysis of how each parameter affected the decision-making, i.e., the best responses, of TSO and GENCO. First, we discuss the effect of the FIP on their decisions. The FIP offers a premium for the amount of electricity generated from RE when a GENCO expands its capacity with RE (L-W-FIP scenario). On the other hand, as mentioned earlier, the amount related to the FIP is treated as a lump sum and offset as a transfer from the consumer to the GENCO (producer). Hence, it does not directly affect the investment timing on the

TSO side.

Proposition 1 *The ceteris paribus increase in the FIP level increases the capacity of GENCO with RE.* [3]

$$\frac{\partial q_1}{\partial F_W} = \frac{\rho - \mu}{2\rho\eta x \alpha_W H} > 0 \tag{2.18}$$

Next, we explain the effect of the installation cost reduction of RE(L-W-Cost scenario) on TSO's and GENCO's decision-making. The proof of Proposition 2 is shown in Appendix A.3.

Proposition 2 *The ceteris paribus reduction in the installation cost of RE hastens the investment timing of the TSO, and increases the capacity of GENCO with RE.*

$$\frac{\partial x}{\partial \xi_W} = \frac{\beta_1}{\beta_1 - 1} \frac{\rho - \mu}{\alpha_W H(1 - \frac{\eta}{2}(Q_{0,W} + Q_{1,W}))} > 0 \tag{2.19}$$

$$\frac{\partial q_1}{\partial \xi_W} = \frac{-\rho(\rho - \mu)}{2\rho\eta x \alpha_W^2 H^2} < 0 \tag{2.20}$$

The third is the effect of the environmental tax on decision-making. Similar to the FIP, the environmental tax is treated as a lump sum on the TSO side and offset as a transfer from the GENCO (producer) to the consumer. Thus, the direct effect is only relevant for the GENCO's decision-making. Besides, since the environmental tax is on CO_2 emissions, it is only involved when the GENCO expands its capacity by LNG(L-L scenario).

Proposition 3 *The ceteris paribus increase in the environmental tax holds down the capacity of GENCO with NRE.*

$$\frac{\partial q_1}{\partial N} = \frac{-\lambda_L(\rho - \mu)}{2\rho\eta x \alpha_L H} < 0 \tag{2.21}$$

Finally, Proposition 4 shows the effect of damage costs on decision-making. The

[3]Ceteris paribus means "all other things being equal." In other words, it means to change only one parameter without changing all the others.

proof of Proposition 4 is given in Appendix A.3. The damage cost is deducted from the social surplus, and it is only relevant to the TSO's investment decision-making.

Proposition 4 *The ceteris paribus increase in damage cost delays the investment timing of the TSO when GENCO expands its capacity with NRE.*

$$\frac{\partial x}{\partial M} = \frac{\beta_1}{\beta_1 - 1} \frac{\rho - \mu}{1 - \frac{\eta}{2}(Q_{0,L} + Q_{1,L})} \frac{\lambda_L}{\rho} > 0 \tag{2.22}$$

Therefore, ceteris paribus changes the best response functions in each parameter shift, which affects the investment timing of the TSO and capacity of the GENCO.

2.4 Numerical case study

2.4.1 Parameters

Table 2.1: Parameter

Capacity factor	α_k	$\alpha_L = 0.85$ $\alpha_W = 0.20$
Expected change rate of demand shock	μ	0
Discount rate	ρ	0.05
Installation cost of Transmission	γ	54,600 yen/kW
Installation cost of Power system	ξ_k	$\xi_L = 120,612$ yen/kW $\xi_W = [100,000, 300,000]$yen/kW
Environmental tax	N	[1,000, 10,000]yen/ton
Damage cost	M	[1,000, 10,000]yen/ton
Variable cost	C_k	C_L=10.98 yen/kWh C_W=3.31 yen/kWh
Carbon dioxide emission factor	λ_k	$\lambda_L = 0.4$ $\lambda_W = 0.0$
FIP price	F_k	$F_L = 0$ yen/kWh $F_W = [0, 20]$yen/kWh
Volatility	σ	[0.1,0.3]

The parameters used in this study are displayed in Table 2.1. The data related to these parameters mainly uses the Projected Costs of Generating Electricity, OECD

/ IEA (2015). We refer to OCCTO (2016) for the installation cost of transmission, and set it at 54,600yen/kW. [4] The installation cost of wind power is about 300,000yen/kW. We also consider the case in which the installation cost of wind power will reduce to 100,000yen/kW because of technological innovations in the future. The value of damage costs is set from 1,000yen/ton to 10,000 yen/ton, by referring to Tol (1995), Tol (2005), Fankhauser (1996), and Krewitt et al. (1999). The value of the environmental tax of 1,000yen/ton is based on OECD (2016) and the Ministry of Environment (2012). We assume that the value of the environmental tax is determined as N=M based on the damage cost M. For this reason, we set the range of N to the same as the damage cost. For volatility σ, we refer to the values used in real option studies in electricity markets, such as Bøckman et al. (2008) and Lavrutich (2017). ρ is referring to Pringles et al. (2014) and Bøckman et al. (2008) as a risk-free rate. Lastly, we refer to Schallenberg-Rodriguez and Haas (2012), Schallenberg-Rodriguez (2014) and Bean et al. (2017) for the FIP level.

2.4.2 Best response function

The TSO and GENCO decide investment timings and capacity expansion after considering each other's decision. Thus, we can regard $q_1(x)$ and $x(q_1)$ as the best response functions. The propositions in Section 2.3 holds for the effect of each parameter on the best response function in this section.

First, Fig. 2.1 shows the best response functions of the L-W scenario with $N = M = 1,000$, $F_W = 0$, $\xi_W = 300,000$ as the base case. The horizontal and vertical axes indicate the investment timing and the capacity, respectively. The intersection of each best response function represents the equilibrium of investment timing and capacity. Fig. 2.1 illustrates the $x(q_1)$ and $q_1(x)$ are increasing functions of each other's variables, which are strategic complements (Tirole, 1988). For the rest of

[4] We assume 300km of transmission lines to be installed.

the figures in this section, we also set $\sigma = 0.1$.

Fig. 2.1 shows the situation without subsidy from FIP in the L-W-FIP scenario ($F_W = 0$), while there is no installation cost reduction in the L-W-Cost scenario ($\xi_W = 300,000$). In other words, Fig. 2.1 is the benchmark case of capacity expansion by wind power, without FIP at the current level of the installation cost of RE. Note that the L-W-Cost scenario and the L-W-FIP scenario have the same outcome in the base case.

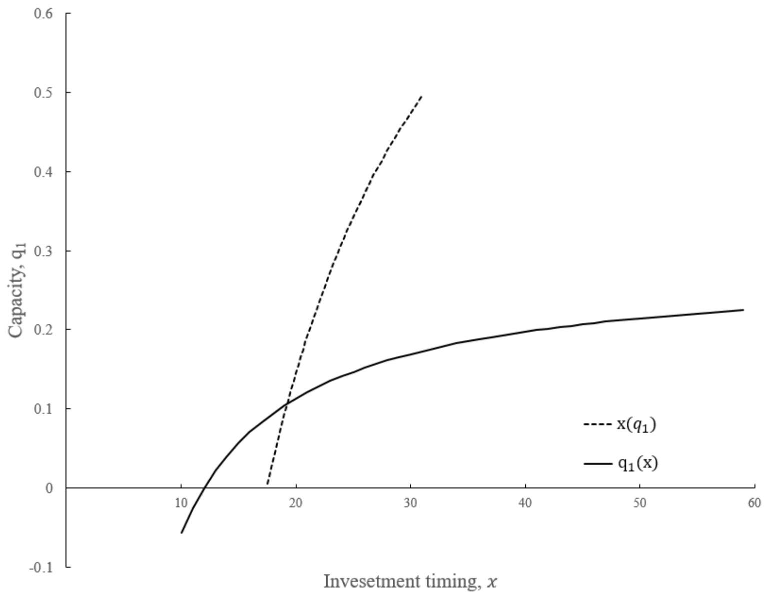

Figure 2.1: Best response function of L-W scenario(Base case)

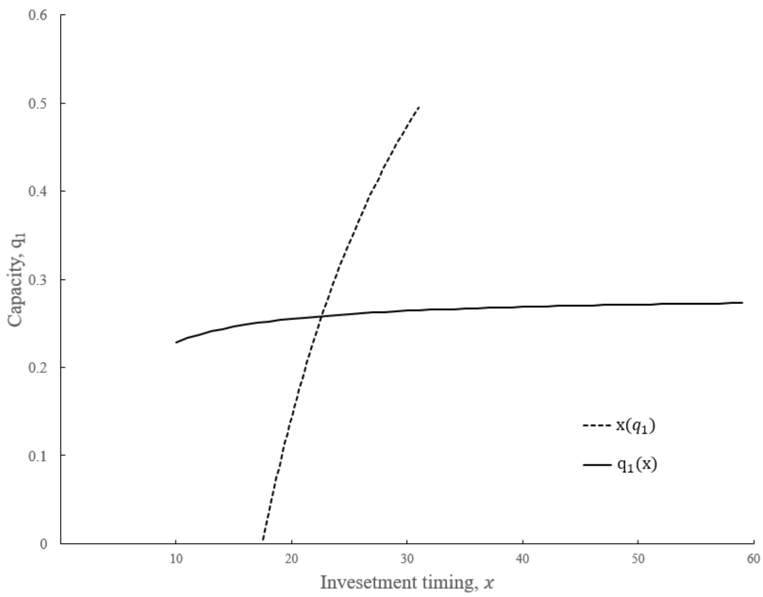

Figure 2.2: Effect of F_W on the best response function for L-W-FIP scenario($F_W = 10$)

Fig. 2.2 depicts the effect of FIP on the best response function of the L-W-FIP scenario with $F_W = 10$. As explained in Proposition 1, the introduction of the FIP pushes up $q_1(x)$, shifts the intersection point upwards, and increases the capacity compared to Fig. 2.1. Although the FIP has no direct effect on the investment timing, the upward shift of $q_1(x)$ moves the intersection point in the right direction for strategic compliments and delays the investment timing.

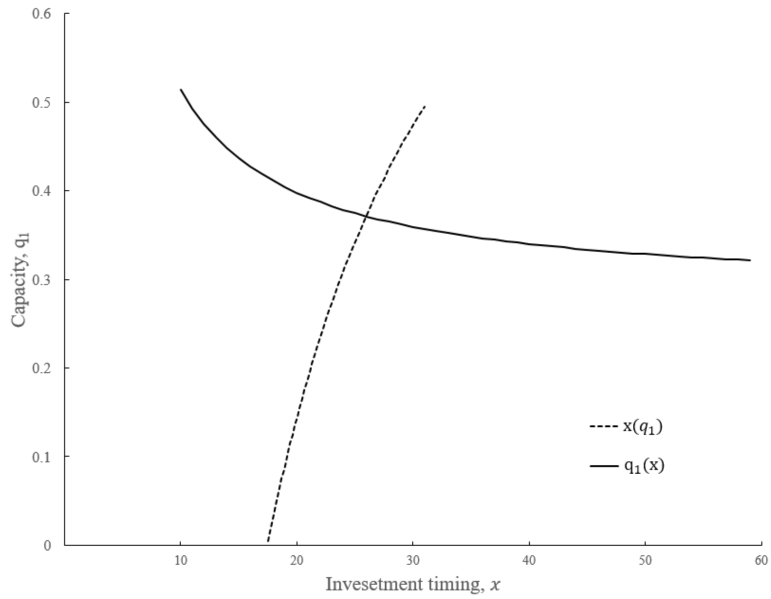

Figure 2.3: Effect of F_W on the best response function for L-W-FIP scenario($F_W =$ 20)

Fig. 2.3 is the best response function for the L-W-FIP scenario with $F_W = 20$. Increasing the FIP level further pushes up $q_1(x)$ and shifts the intersection point upward. Hence the larger capacity becomes the optimal decision in this case. The investment timing is also delayed because the intersection point shifts in the right direction due to the indirect effect of FIP, same as in Fig. 2.2.

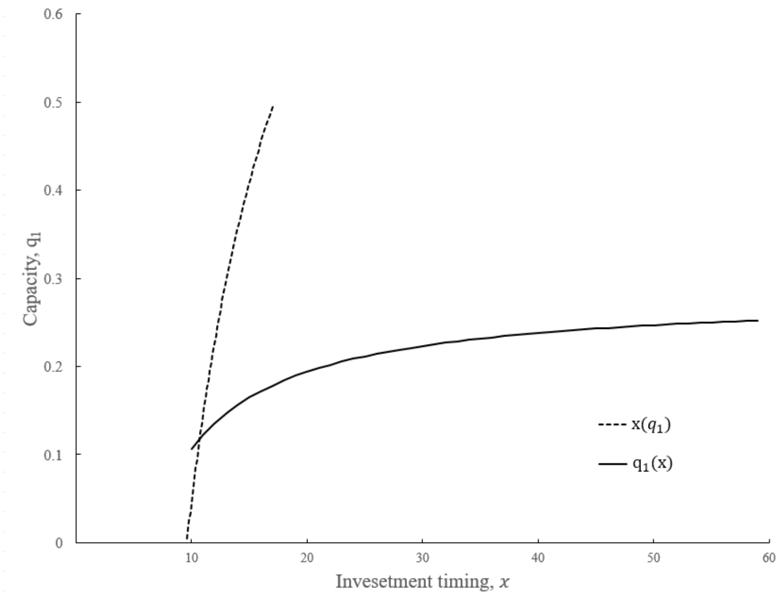

Figure 2.4: Effect of ξ_W on the best response function for L-W-Cost scenario($\xi_W = 100,000$)

Next, we examine the effect of the reduction in the installation cost of RE on the best response function using the L-W-Cost scenario with $\xi_W = 100,000$. In Fig. 2.4, consistent with Proposition 2, $q_1(x)$ shifts upward, while $x(q_1)$ shifts leftward. Hence, the reduction in the installation cost of RE shifts both $q_1(x)$ and $x(q_1)$ simultaneously in the L-W-Cost scenario. The equilibrium is determined, depending on the magnitude of the effect of accelerating the investment timing and increasing the capacity through these shifts. The upward shift of $q_1(x)$ increases the capacity, and the leftward shift of $x(q_1)$ decreases it, where $q_1(x)$ and $x(q_1)$ are strategic complements. These two effects offset each other in our case study, resulting in almost no change in the capacity expansion. On the other hand, the effect of accelerating the investment timing by shifting $x_1(q)$ leftward is greater than the effect of delaying the investment timing by shifting $q_1(x)$ upward. As a result, the investment timing becomes earlier in our setting.

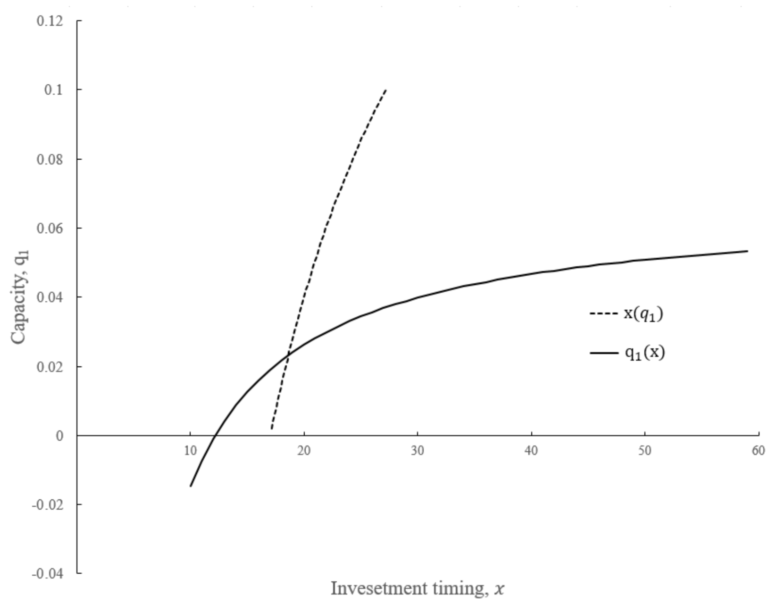

Figure 2.5: Best response function of L-L scenario(Base case)

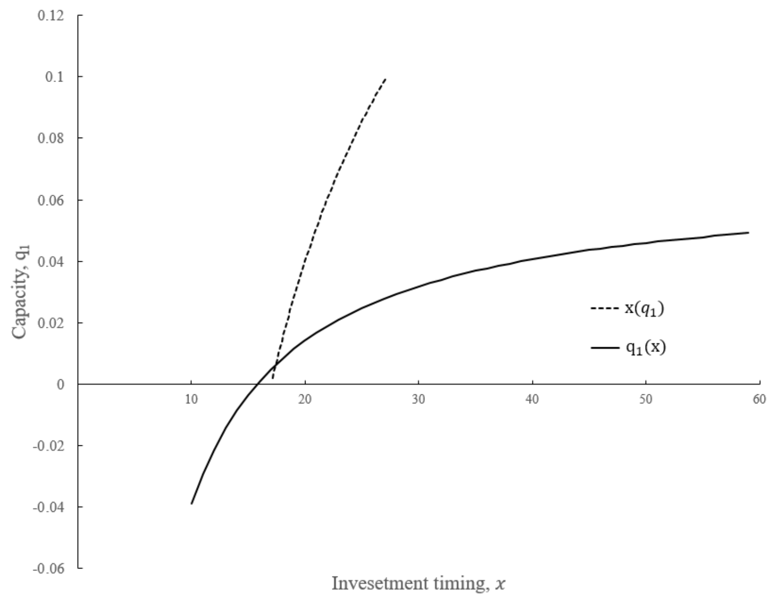

Figure 2.6: Effect of N on the best response function for L-L scenario($N = 10,000$)

Fig. 2.5 displays the base case of the L-L scenario, where $N = M = 1,000$. Fig. 2.6 is the L-L scenario with only N increasing to $N = 10,000$. Consistent with Proposition 3, the increase in the environmental tax shifts $q_1(x)$ downward, and decreases the capacity. On the other hand, although the environmental tax does not directly affect the investment timing, the effect of the downward shift of $q_1(x)$ moves the intersection point to the left compared to Fig. 2.5, which hastens the investment timing.

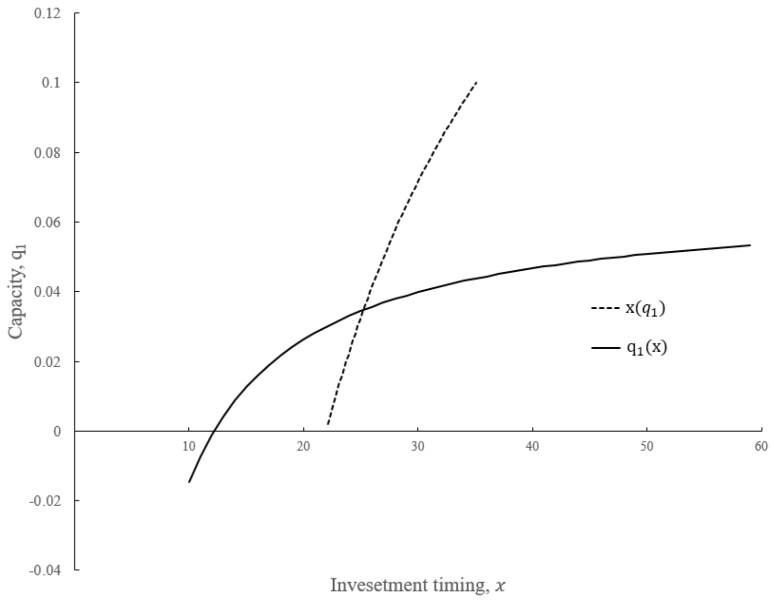

Figure 2.7: Effect of M on the best response function for L-L scenario($M = 10,000$)

Finally, we discuss the effect of damage costs on the best response function. In Fig. 2.7, the effect of increasing the damage cost shifts $x(q_1)$ to the right, and delays the investment timing. Although the damage cost has no direct effect on capacity expansion, the effect of shifting $x(q_1)$ to the right moves the intersection point upwards, which increases the capacity expansion. Note that Fig. 2.6 and Fig. 2.7 shows the effect of the environmental tax and damage costs on the L-L scenario separately. However, in the following analysis, the equilibrium is determined simultaneously by the two effects under the assumption of $N = M$.

2.4.3 Comparison of L-L scenario and L-W-Cost scenarios

Next, we compare each scenario in terms of investment timing, capacity expansion, and social surplus. We start with the comparison of the L-L scenario and the L-W-Cost scenario.

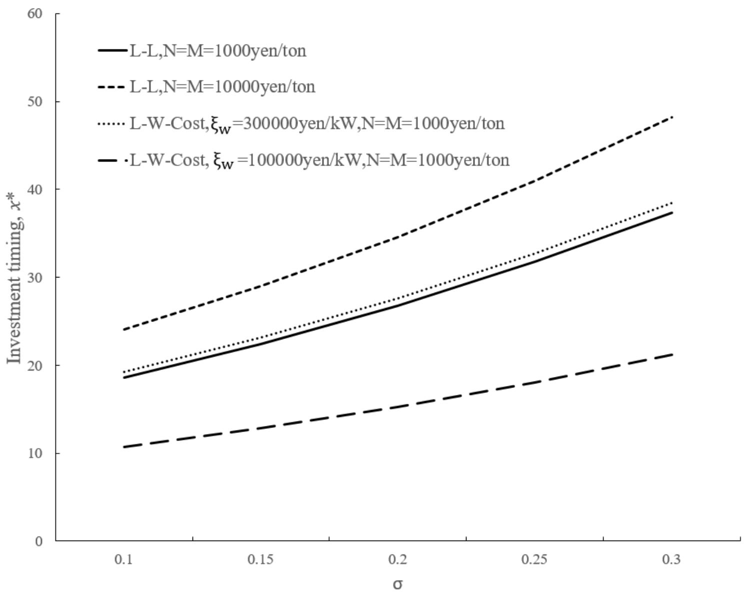

Figure 2.8: Comparison of x^* in L-L and L-W-Cost scenarios

In Fig. 2.8, we compare the equilibrium investment timing for the L-L and L-W-Cost scenarios. In the base case comparison of the L-L scenario($N = M = 1,000$) and the L-W-Cost scenario($\xi_W = 300,000$), each investment timing is almost the same but it is slightly delaying for the L-W-Cost scenario. In the L-L scenario, as shown in Fig. 2.6 and Fig. 2.7, increases in N and M affect the outcome. In this case, the effect of delaying the investment timing due to the increase in M is larger than the indirect effect of hastening the investment timing due to the increase in N, which makes x^* larger and leads to a delay in investment. On the other hand, in the L-W-Cost scenario, the equilibrium investment timing x^* hastens due to the decrease in ξ_W.

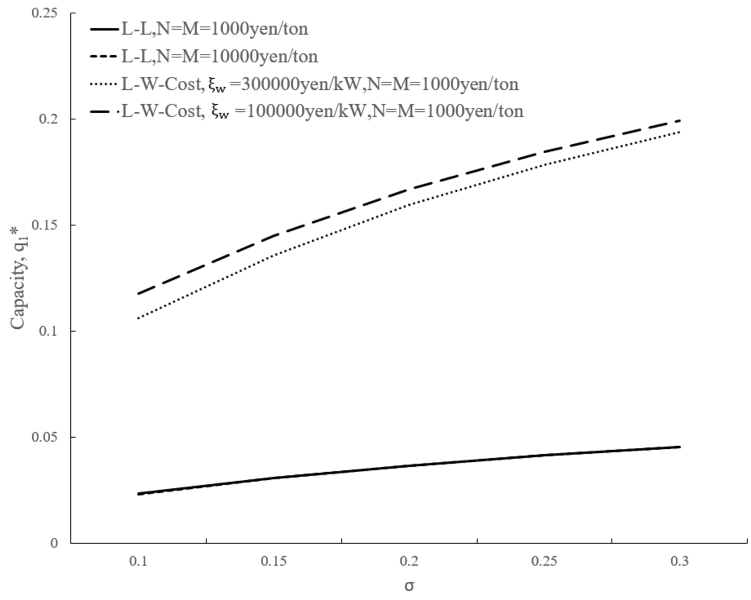

Figure 2.9: Comparison of q_1^* in L-L and L-W-Cost scenarios

Fig. 2.9 is a comparison of the equilibrium capacity expansion for each scenario. The capacity decreases as N increases for the L-L scenario (N=M=10,000), as shown in Fig. 2.6. However, as depicted in Fig. 2.7, there is also the indirect effect of increasing capacity by delaying investment timing with an increase in M, resulting in q_1^* remaining almost unchanged, only slightly smaller than in the base case of the L-L scenario. In the L-W-Cost scenario, the capacity increases as ξ_W is reduced. Simultaneously, the capacity decreases because of the indirect effect of hastening investment timing with the decrease in ξ_W, as shown in Fig. 2.4. With these two effects, the increase in the capacity is limited in the L-W-Cost scenario. As can be seen from Fig. 2.9, the L-W-Cost scenario leads to more generating capacity to satisfy the electricity demand, because the capacity factor of power generation from RE is lower than that from NRE.

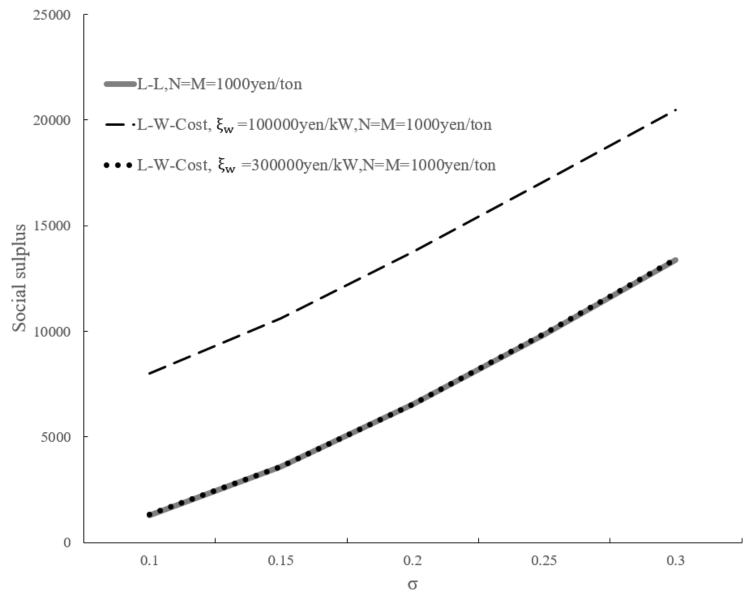

Figure 2.10: Comparison of social surplus in L-L and L-W-Cost scenarios (N=M=1,000)

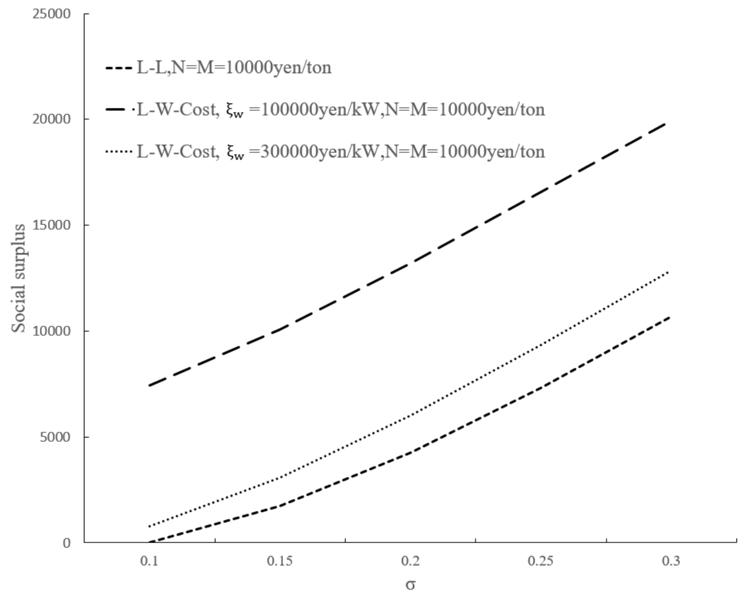

Figure 2.11: Comparison of social surplus in L-L and L-W-Cost scenarios (N=M=10,000)

We present the social surplus of $N = M = 1,000$ case in Fig. 2.10 and $N = M = 10,000$ case in Fig. 2.11. The base cases of the L-W-Cost scenario and the L-L scenario indicates almost the same social surplus, but that of the L-W-Cost scenario is slightly larger for all σ in Fig. 2.10. Furthermore, when the installation cost reduction is realized in the L-W-Cost scenario ($\xi_W = 100,000$), the social surplus increases significantly. In Fig. 2.11, the L-L scenario is affected by the increase in N and M, which leads to a delay in the investment and a reduction in capacity. This results in decreasing the social surplus. [5]

2.4.4 Comparison of L-W-FIP scenario and L-W-Cost scenarios

In this section, we finally discuss the comparison between the L-W-FIP scenario and the L-W-Cost scenario in terms of investment timing, capacity expansion, and social surplus.

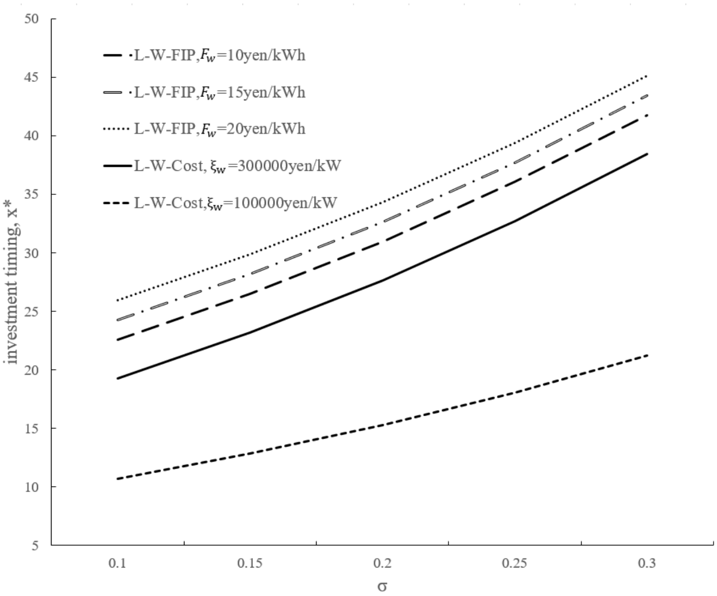

Figure 2.12: Comparison of x^* for L-W-FIP scenario and L-W-Cost scenarios

Fig. 2.12 compares the equilibrium investment timing of the L-W-FIP and L-W-Cost

[5]The L-W-Cost and L-W-FIP scenarios are affected by the damage cost due to the initial capacity q_0 of LNG before investment, but the magnitude is smaller compared to that in the L-L scenario.

scenarios. The investment in the L-W-FIP scenario is delayed due to the indirect effect of increasing capacity with the rise in F_W, as shown in Figs. 2.2 and 2.3. As a result, the investment timing of the L-W-FIP scenario is more delayed compared to the L-W-Cost scenario.

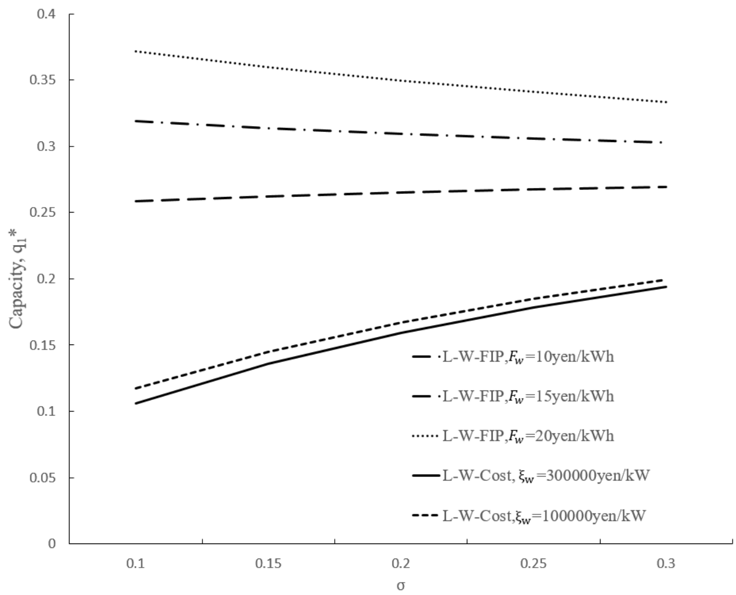

Figure 2.13: Comparison of q_1^* in L-W-FIP and L-W-Cost scenarios

Fig. 2.13 is the comparison of equilibrium capacity between the L-W-FIP and the L-W-Cost scenarios. The L-W-FIP scenario is affected by the increase in F_W, leading to a larger capacity expansion decision compared to the L-W-Cost scenario. In Fig. 2.12 and Fig. 2.13, the FIP exhibits a relatively small effect on the investment timing but a large effect on the capacity. In contrast, the installation cost reduction of RE has a large effect on the investment timing but a small effect on the capacity expansion. Overall, the equilibrium decision under the FIP is to increase the capacity significantly, while somewhat delaying the investment.

Another remarkable observation emerges from Fig. 2.13. In a general framework of real options with capacity choice, the capacity tends to increase with the investment threshold because the threshold is usually an increasing function of the capacity. However, Fig. 2.13 illustrates cases in which the capacity can decrease with a higher investment threshold. This is because the incentive to increase capacity with operating costs decreases when higher profits can be expected due to the high FIP level (premium) and volatility. The analysis of the best response functions regarding the relationship between capacity and threshold could distinguish between the general characteristic of real options and the effect of policies such as FIP.[6]

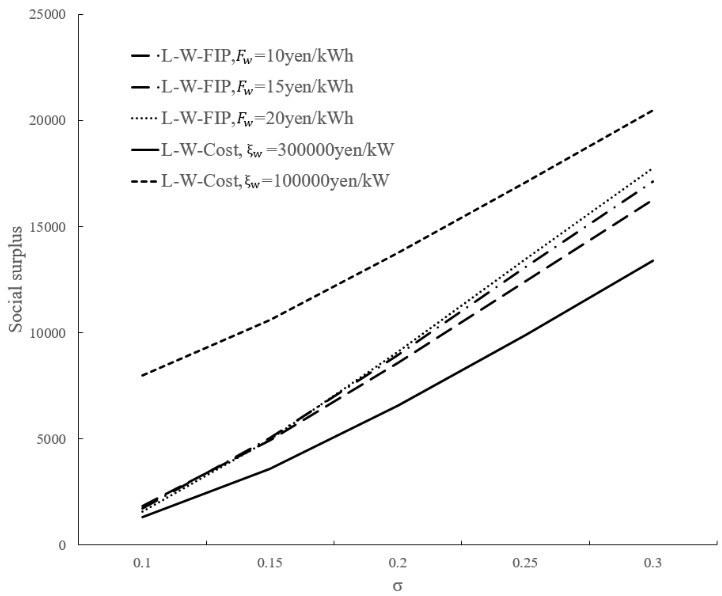

Figure 2.14: Comparison of social surplus in L-W-FIP and L-W-Cost scenarios (N=M=10,000)

Fig. 2.14 shows the comparison of the social surplus between the L-W-FIP scenario and the L-W-Cost scenario. The L-W-FIP scenario (F_W=10, 15, and 20) and the L-W-Cost scenario with installation cost reduction($\xi_W = 100,000$) have a larger social surplus than the base case of the L-W-Cost scenario. Moreover, as shown in the previous section, the base case of the L-W-Cost scenario has a larger social surplus

[6]The relationship between q_1^* and σ follows the partial differential equation, $\frac{\partial q_1^*}{\partial \sigma} = \frac{\partial q_1^*}{\partial x^*}\frac{\partial x^*}{\partial \sigma} = \frac{(\rho-\mu)\{\alpha_k H(C_k - F_k + \lambda_k N) + \rho\xi_k\}}{2\rho\eta\alpha_k^2 h^2 x^{*2}}\frac{\partial x^*}{\partial \sigma}$. If $\frac{\partial x^*}{\partial \sigma} > 0$ (see Fig. 2.12) and $\alpha_k H\left(C_k - F_k + \lambda_k N\right) + \rho\xi_k > 0$, q_1^* is an increasing function of σ because of $\frac{\partial q_1^*}{\partial \sigma} > 0$. On the other hand, if $\frac{\partial x^*}{\partial \sigma} > 0$ and $\alpha_k H\left(C_k - F_k + \lambda_k N\right) + \rho\xi_k < 0$, q_1^* is a decreasing function of σ because of $\frac{\partial q_1^*}{\partial \sigma} < 0$. In Fig. 2.13, the low FIP level case (F_W=10) is the former, and the high FIP level cases (F_W=15, 20) are the latter in the L-W-FIP scenario.

than the L-L scenario. Thus, the social surplus of L-W-FIP and L-W-Cost scenarios become larger than that of the L-L scenario, which implies the effectiveness of the FIP and reduction in installation cost.

In the L-W-FIP scenario, the difference in capacity expansion among FIP levels is relatively large in the range of small σ. In this range, the higher FIP level induces a relatively larger capacity expansion, and incurs higher costs. Therefore, the lower FIP level has a larger social surplus in the small range of σ. On the contrary, in the range where σ is large, the difference in capacity expansion among FIP levels is relatively small, so the difference in cost burden is also relatively small. As a result, a higher FIP level leads to a larger social surplus due to the larger effect of FIP in the range of large σ. This implies that the social surplus under the higher FIP level (F_W=20) rises more steeply as σ increases when compared to the lower FIP level (F_W=10). Fig. 2.14 also suggests that the L-W-Cost scenario brings a larger social surplus than the L-W-FIP scenario, if the installation cost of RE decreases significantly in the future. In such a case, a larger social surplus may be achieved without implementing the FIP. The installation cost reduction of RE may be enhanced by further investment in R&D.

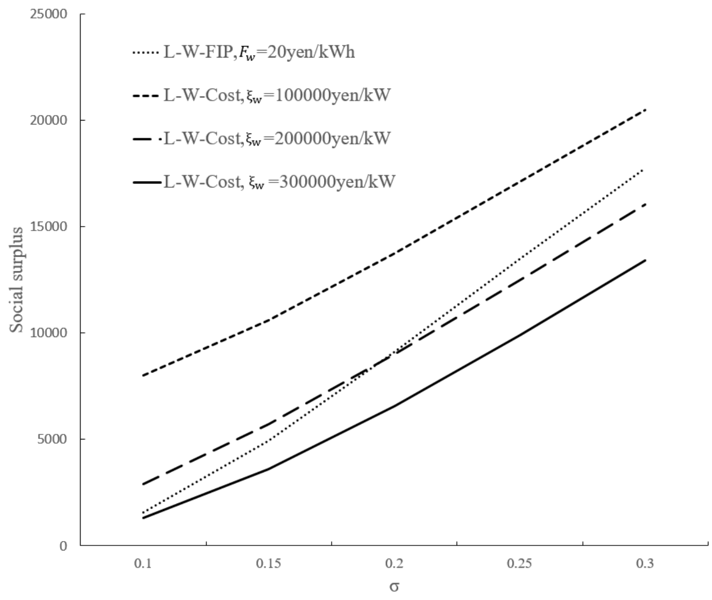

Figure 2.15: Comparison of social surplus of the L-W-FIP and L-W-Cost scenarios in the transition period

Fig. 2.15 demonstrates the comparison of the social surplus with the L-W-FIP scenario ($F_W = 20$) and the L-W-Cost scenario, when the installation cost of RE reduces gradually from the current level $\xi_W = 300,000$ to $\xi_W = 200,000$ and $\xi_W = 100,000$. Now focusing on the L-W-Cost with $\xi_W = 200,000$, there is an intersection point with the L-W-FIP scenario. If the sigma is small (to the left side of the intersection point), a larger social surplus can be obtained by reducing only the installation cost of RE, without implementing the FIP in this case. This implies that social surplus can be increased without the financial burden of implementing FIP. On the other hand, if σ is large (to the right side of intersection point), even with the reduction in the installation cost of RE ($\xi_W = 200,000$), the implementation of FIP is still advantageous in terms of social surplus. Thus, uncertainty would play an important role in determining the environmental policy during the transition period of installation cost reduction.

2.5 Conclusion

This study examined the problems of investment timing and capacity expansion for TSO and GENCO. By applying a game theory framework and the real options approach, we analyzed the decision-making and equilibria under uncertainty in the transmission and generation sectors. Furthermore, we considered three scenarios: the implementation of FIP (L-W-FIP), the reduction in the installation cost of RE (L-W-Cost), and capacity expansion by NRE (L-L). We showed that the FIP has a significant effect on capacity expansion in the L-W-FIP scenario. On the other hand, the installation cost reduction of RE significantly affects the investment timing in the L-W-Cost scenario. This indicates that the equilibrium decision in the L-W-FIP scenario is to delay the investment timing and expand the larger capacity, while that in the L-W-Cost scenario is to control the capacity and hasten investment timing. From the result of the social surplus in the L-W-FIP scenario and the base case of the L-W-Cost scenario, we found that FIP has the effect of increasing the social surplus. In the range with less uncertainty, the social surplus is larger when the FIP level is lower. Meanwhile, in the range with more uncertainty, the social surplus is larger when the FIP level is higher. These results indicate that the FIP level should be set based on the degree of uncertainty. In the transition period for reduction of the installation cost, the social surplus of the L-W-FIP scenario can be greater in the range of more uncertainty. In contrast, the social surplus of the L-W-Cost scenario becomes larger in the range of less uncertainty. This suggests that the implementation of FIP depends on the degree of uncertainty. In the future, if the installation cost reduction of RE is sufficiently advanced to the same level as the installation cost of NRE, the social surplus in the L-W-Cost scenario could be larger than the L-W-FIP scenario. In that case, the financial burden could be reduced without implementing FIP policy.

Finally, although this study focused on wind power generation and FIP, analyses of other RE sources such as solar PV power generation and other RE policies such as RPS are possible as future research topics. In addition, extending the analytical framework, such as increasing the number of players to reflect more realistic market settings, is another area for future research.

Chapter 3

Prosumers' investment decisions under different pricing schemes

3.1 Introduction

Further investment in DERs and their efficient operation is necessary for decarbonization and sustainable energy systems. In particular, the emergence of prosumers who own renewable DERs has brought about a paradigm shift in the electricity market. The prosumer is an entity that consumes electricity, similar to a conventional consumer, while simultaneously generating electricity as a producer to supply it in the electricity market using its own power generation resources. On the one hand, the increase in the number of prosumers who own DERs contributes to the spread of RE. Child et al. (2020) show that prosumer investment in RE, particularly PVs, is essential to increase the share of RE in the future based on the Finnish case study. In addition, they indicate that prosumers need to cover 26% of the final electricity demand by 2050, and energy storage will be an important issue because RE is highly sensitive to seasonal and weather conditions. The increase in the number of prosumers is also expected to contribute to resilience in the electricity market, in anticipation of climate change and natural disasters (Lia et al., 2019). Thus, it is critical to design regulations and policies that consider prosumer investment and electricity trading to realize an efficient energy system in the future. In Europe and the U.S., energy policies related to prosumers have been enacted and discussed actively (Inês et al., 2020; Parag and Sovacool, 2016).

On the other hand, the increase in the volume of DERs [7] may cause the fixed cost recovery problem vis-à-vis electric power transmission systems; this is referred to as the death spiral. Owing to the increase in the prosumer self-consumption of electricity from DERs, fewer consumers are to bear the fixed costs of transmission systems. Eventually, it becomes difficult to recover the fixed cost of networks, which leads to the death spiral issue (Felder and Athawale, 2014). Hence, simply subsidizing and increasing investment in DERs may cause negative side effects, such as a death spiral. Kuznetsova and Anjos (2021) show that off-grid electricity consumption will be the most attractive option for electricity consumers by 2030, and the increase in consumers converting to off-grid power systems, that is, an increase in prosumers, will result in a higher proportion of fixed costs in electricity prices in some regions. They also show that additional energy policies are necessary to avoid future disruptions to the energy system. Thus, it is necessary to recover the fixed cost for the expansion and maintenance of networks by increasing DER penetration via appropriate tariffs and pricing schemes that can address the death spiral problem (Borenstein, 2016).

To promote RE and strengthen the resilience of electricity power systems, it is indispensable to examine regulatory designs and energy policies that increase the number of prosumers, while considering the recovery of fixed costs of transmission systems. In addition, prosumers may have a significant influence on the decisions of other market participants. Therefore, it is relevant to consider the decisions of not only prosumers but also other market participants in the electricity market, such as consumers, producers, and independent system operators (ISOs), when conceptualizing such regulatory designs and energy policies. In this study, we analyze the market equilibrium of the entire electricity market, including prosumers, by considering fixed cost recovery under several pricing schemes for prosumers.

[7] DERs include several different types of technologies such as cogeneration systems. In this analysis, we focus on RE power generation systems owned by prosumers.

There are many studies on the relationship between prosumers and pricing schemes. Eid et al. (2014) found that net metering provides an incentive for prosumers to invest in PVs. Net metering assesses the sale of electricity from DERs to the market and the electricity purchase from the market at the same price (e.g., retail price) and offsets the amount of sale and purchase for payment or compensation. However, net metering affects cost recovery and increases network charges, indicating that a proper tariff design for net metering is needed to solve this problem. Gautier et al. (2018) showed that, on the one hand, net metering would lead to an excessive increase in the number of prosumers, thereby reducing their payment for costs associated with the network, while consumers bear high costs. They discussed that net metering can be an attractive option for prosumers but may not be so for consumers. On the other hand, they also suggested that net purchase (or net billing herein) may contribute to the avoidance of the problem of excessive investment in PVs and increasing grid charges. Net billing values electricity sale from DERs to the market and electricity purchase from the market at different prices, where the amount of sale and purchase are recorded separately for payment and compensation. Villena et al. (2021) analyzed the impact of the integration of prosumers into the network under net metering and net billing on prosumer PV adoption, battery storage installation, and the energy cost of non-prosumers based on a case study in Belgium. They showed that net metering encourages investment in PVs but does not encourage investment in battery storage or self-consumption, while net billing does not encourage investment in PVs but encourages investment in battery storage and self-consumption. They also suggested that it is desirable to shift from net metering to net billing in the long term.

Given the growing interest in energy storage, we also analyze the impact of battery storage on the social surplus in the context of prosumer battery operation. Camilo et al. (2017) examined the profitability of prosumers with small-scale PVs based on several scenarios that combine the size of the generating facility, battery storage, and self-consumption. The results showed that the scenario with small-scale PV facilities and self-consumption yields the highest profit. They also indicated that the scenario with battery storage does not generate sufficient profit because the cost is still relatively high, despite the recent decrease in the capital cost of batteries. Sioshansi (2014) examined the potential welfare effects of storage under a multitude of market structures. They demonstrated that storage reduces allocative efficiency relative to not having storage in the electricity market with strategic generating firms. By extending Sioshansi (2014), Siddiqui et al. (2019) examined the welfare impacts of profit-maximizing merchant storage operator. They found that profit-maximizing storage investment does not necessarily lead to the maximization of social welfare.

Notably, these previous studies did not analyze market equilibrium considering the realistic loop flow in the transmission network. A recent study by Ramyar et al. (2020) extended the model of Hobbs (2001) and analyzed the market equilibrium with and without the market power of prosumers using a complementarity approach for an electricity market that includes prosumers, consumers, producers, and grid operators. However, to the best of our knowledge, merely a few studies have analyzed market equilibrium while considering the loop flow in networks, pricing schemes, prosumer investment in RE, and battery operation.

The purpose of this study is to analyze the decision-making of each market participant (prosumers, consumers, producers, and ISOs) in the electricity market in equilibrium, focusing on the investment decisions of prosumers, the level of transmission tariffs, and the total social surplus. In this study, we formulate complementarity problems for all market participants, considering different pricing schemes, electric power networks, prosumer investments in PVs, and battery operations. First, we discuss that the capacity of PVs invested in by prosumers and the total social surplus increase as the capital costs of PVs decrease under both pricing schemes without considering battery operation. Next, we show that battery operation increases the capacity of prosumer investment in PV under both pricing schemes. Furthermore, the total social surplus under net billing is larger than that under net metering, with and without battery operation. We find that net billing provides a larger social surplus in our setting.

The remainder of this paper is organized as follows: in Section 3.3, we formulate the optimization problems by considering the fixed cost recovery of the network. In Section 3.4, we characterize two different pricing schemes. In Section 3.5, we explain the data and settings in this study and present numerical case studies of prosumer investment in PV systems with and without battery operation. We present the conclusion in Section 3.6.

3.2 Nomenclature

Sets

I, T, S	Sets of nodes, periods, and links
$h \in H_i$	Set of generation units at node i

Parameters

$PTDF_{si}$	Power transmission distribution factor for a unit of power transferred from the hub to node i through line s
P^0_{it}, Q^0_{it}	Vertical and horizontal intercepts of the inverse demand function in node i at period t (\$/MWh)
α_i	Fraction of prosumers at node i
B_t	Number of hours in period t
E	Annualized capital cost of solar PV panels (\$/MW-year)
CF_t	Capacity factor of RE at period t
G_i	Production capacity of prosumer dispatchable unit at node i (MW)

	at node i (MW)
X_{ih}	Production capacity for generation unit h in node i (MW)
T_s	Thermal limit for link s (MW)
R	Fixed cost of transmission owners ($/year)
V^{ch}	Charging efficiency of battery storage
V^{dc}	Discharging efficiency of battery storage
D	Days in a year
M_{it}	Self-discharge rate at node i in period t
σ^{max}	Upper limit of usable capacity as ratio to battery capacity W_i
σ^{min}	Lower limit of usable capacity as ratio to battery capacity W_i
β^{ch}	Rate of charge allowance per hour for battery capacity W_i
β^{dc}	Rate of discharge allowance per hour for battery capacity W_i
U	Annualized capital cost of battery storage ($/MW-year)
W_i	Battery capacity at node i (MW)

Primal Variables

d_{it}	Consumer demand in node i at period t (MWh)
l_{it}	Prosumer demand in node i at period t (MWh)
τ	Transmission tariff for purchases or subsidy for sales under net metering ($/MWh)
τ^b, τ^s	Transmission tariff for purchases and subsidy for sales under net billing ($/MWh)
z_{it}	Prosumer sales or purchases in node i at period t under net metering (MWh)
z_{it}^s, z_{it}^b	Prosumer sales and purchases in node i at period t under net billing (MWh)
g_{it}	Electricity produced by prosumer dispatchable unit

	in node i at period t (MWh)
k_i	Capacity of RE investment by prosumers (MW)
x_{iht}	Electricity generated by generation unit h in node i at period t (MWh)
y_{it}	Electricity injection or withdrawal at node i at period t (MWh)
ch_{it}	Charge of battery storage in node i at period t (MWh)
dc_{it}	Discharge of battery storage in node i at period t (MWh)
bat_{it}	Amount of electricity stored in battery storage in node i at the end of period t (MWh)

Dual Variables

δ_{it}	Dual variable for prosumer energy balance in node i at period t (\$/MWh)
κ_{it}	Dual variable for prosumer dispatchable generation in node i at period t(\$/MWh)
ρ_{iht}	Dual variable for producer power generation unit h in node i at period t(\$/MWh)
θ_t	Dual variable for injection or withdrawal at period t (\$/MWh)
$\lambda_{st}^{+}, \lambda_{st}^{-}$	Dual variables for limit of line k at period t (\$/MW)
p_{it}	Dual variable for supply and demand balance in node i (wholesale power price in node i) (\$/MWh)
μ_{it}^{max}, μ_{it}^{min}	Dual variables for upper and lower limit of battery storage (\$/MW)
γ_{it}^{ch}, γ_{it}^{dc}	Dual variables for charge and discharge in node i at period t (\$/MWh)
η_{it}	Dual variable for transition of battery storage (\$/MWh)

3.3 Model

In this study, we model the annual decision-making of prosumers, consumers, producers, and the ISO in a situation where multiple nodes are connected via transmission lines, and each node's electricity demand varies in each period. First, we consider the optimization problems for each market participant and derive the Karush–Kuhn–Tucker (KKT) conditions. Thereafter, we define the market equilibrium problem in the electricity market by overall KKT conditions for all market participants and the condition for the fixed cost recovery of networks.

3.3.1 Consumers

Consumers and prosumers consume electricity in each period at each node. The total consumption is expressed as the sum of the electricity consumption of consumers d_{it} and that of prosumers l_{it}. The retail inverse demand function at period t at node i can be expressed using the sum of the electricity consumption of consumers and prosumers.

$$p_{it}^{r}(d_{it} + l_{it}) = P_{it}^{0} - \frac{P_{it}^{0}}{Q_{it}^{0}}(d_{it} + l_{it}) \tag{3.1}$$

Here, P_{it}^{0} and Q_{it}^{0} are the vertical and horizontal intercepts of the inverse demand function, respectively, and p_{it}^{r} can be considered as the retail price. Next, the inverse demand functions or the marginal benefit functions of consumers and prosumers in period t at node i can be obtained using the fraction of the prosumers at node i, $\alpha_i(0 \leq \alpha_i \leq 1)$. They can be represented by the following inverse demand functions $p_{it}^{con}(d_{it})$, $p_{it}^{pros}(l_{it})$, respectively.

$$p_{it}^{con}(d_{it}) = P_{it}^0 - \frac{P_{it}^0}{(1-\alpha_i)Q_{it}^0} d_{it} \tag{3.2}$$

$$p_{it}^{pros}(l_{it}) = P_{it}^0 - \frac{P_{it}^0}{\alpha_i Q_{it}^0} l_{it} \tag{3.3}$$

Note that the horizontal intercept is divided by α_i. Finally, the wholesale price in period t at node i is obtained by subtracting the transmission tariff for fixed cost recovery from the retail price, expressed as $p_{it} = p_{it}^r - \tau$ in net metering and $p_{it} = p_{it}^r - \tau^b$ in net billing.

3.3.2 Prosumers under different pricing schemes

We consider prosumer investment in RE over an annual time horizon. Our focus is on PVs, e.g., rooftop solar panels, which are typical RE sources for prosumers. Prosumers decide on investment in PVs, electricity consumption, electricity sales or purchases, and backup power generation under the net metering and net billing schemes to maximize their profits.

Net metering

Net metering is a system for prosumers that records the amount of electricity sold from prosumers' DERs to the grid (z_{it} >0) and the amount of electricity purchased from the market via the network (z_{it} <0), offsetting them with a bi-directional meter. This scheme allows prosumers to pay (or be compensated) for the net electricity purchase (or sale). Prosumers under net metering schemes face the same price, $p_{it} + \tau$, for both electricity sales (z_{it} >0) and purchases (z_{it} <0). In other words, τ acts as a subsidy for sales and as a tariff for purchases. The prosumer optimization problem under the net metering scheme in period t at node i can be expressed as follows:

$$
\begin{aligned}
\underset{l_{it}, g_{it}, k_i \geq 0, z_{it}}{\text{maximize}} \quad & \sum_t (p_{it} + \tau) z_{it} B_t + \sum_t \left(\int_0^{l_{it}} p_{it}^{pro}(m_{it}) dm_{it} \right) B_t \\
& \qquad - \sum_t C_i^g(g_{it}) B_t - Ek_i \qquad (3.4)
\end{aligned}
$$

subject to

$$(z_{it} + l_{it} - CF_t k_i - g_{it})\, B_t \leq 0 \qquad (\delta_{it}) \qquad (3.5)$$

$$(g_{it} - G_i)\, B_t \leq 0 \qquad (\kappa_{it}) \qquad (3.6)$$

Prosumers determine the amount of electricity consumption l_{it}, electricity sales/purchases z_{it}, backup electricity g_{it} at each node and each period, and the capacity of investment in PVs k_i to maximize their objective function, as expressed in Eq. (3.4). The objective function consists of the revenue/payment associated with electricity sales/purchases, benefits from electricity consumption, cost of backup generation, and investment cost for the capacity of PVs. Eq. (3.5) is a constraint on the prosumer energy balance to be satisfied in the short term. Prosumers match the electricity consumption l_{it}, the electricity sales/purchases z_{it}, the backup electricity g_{it}, and the output $CF_t k_i$, which varies from one period to another depending on the capacity factor. Eq. (3.6) is a constraint on the amount of backup electricity. Using this optimization problem, we can derive the following KKT conditions:

$$(p_{it} + \tau - \delta_{it})B_t = 0, \forall i, \forall t \tag{3.7}$$

$$0 \leq l_{it} \perp \left(P_{it}^0 - \frac{P_{it}^0}{\alpha_i Q_{it}^0} l_{it} - \delta_{it} \right) B_t \leq 0, \forall i, \forall t \tag{3.8}$$

$$0 \leq g_{it} \perp \left(-C_i^{g'}(g_{it}) + \delta_{it} - \kappa_{it} \right) B_t \leq 0, \forall i, \forall t \tag{3.9}$$

$$0 \leq k_i \perp -E + \sum_t CF_t \delta_{it} B_t \leq 0, \forall i \tag{3.10}$$

$$0 \leq \delta_{it} \perp (z_{it} + l_{it} - CF_t k_i - g_{it}) B_t \leq 0, \forall i, \forall t \tag{3.11}$$

$$0 \leq \kappa_{it} \perp (g_{it} - G_i) B_t \leq 0, \forall i, \forall t \tag{3.12}$$

From Eqs. (3.7) and (3.8), prosumers in the net metering scheme determine the electricity consumption l_{it} such that the marginal benefit is equal to the retail price $p_{it} + \tau$ in each period, which can be regarded as a condition for a short-term decision. Moreover, from Eq. (3.10), the prosumer investment in the capacity of PVs k_i is determined to ensure that the investment cost per MW-year E is equal to the annual average retail price weighted by the capacity factors over a year. This can be regarded as a condition for long-term decision-making.

Net billing

Prosumers in the net billing scheme face different prices when selling electricity from their DERs to the grid and buying electricity from the power market through the network. Therefore, net billing requires two meters to record the amount of electricity separately for sales (z_{it}^s) and purchases (z_{it}^b). The prosumer optimization problem in period t at node i under the net billing mechanism can be expressed as follows:

$$\underset{l_{it},g_{it},k_i,z_{it}^s,z_{it}^b\geq 0}{\text{maximize}} \quad \sum_t \left((p_{it}+\tau^s)z_{it}^s-(p_{it}+\tau^b)z_{it}^b\right)B_t$$
$$+\sum_t\left(\int_0^{l_{it}} p_{it}^{pro}(m_{it})dm_{it}\right)B_t-\sum_t C_i^g(g_{it})B_t \quad -Ek_i \tag{3.13}$$

subject to

$$(z_{it}^s-z_{it}^b+l_{it}-CF_tk_i-g_{it})B_t\leq 0 \qquad (\delta_{it}) \tag{3.14}$$

$$(g_{it}-G_i)B_t\leq 0 \qquad (\kappa_{it}) \tag{3.15}$$

Similar to net metering, prosumers in the net billing plan also determine the amount of electricity consumption l_{it}, electricity sales z_{it}^s, electricity purchases z_{it}^b, backup electricity generation g_{it} at each node and each period, and the capacity of PVs k_i. Thereafter, they maximize their objective function comprising the revenue/payment from electricity sales/purchases, benefits from electricity consumption, cost of backup electricity generation, and investment cost for the capacity of PVs. In net billing, when prosumers sell electricity (z_{it}^b=0, z_{it}^s >0), prosumers face the price $p_{it}+\tau_s$. Here, τ_s can be positive or negative. When τ_s >0, τ_s acts as a subsidy for electricity sales, while τ_s <0 acts as a tariff for electricity sales, thus contributing to the recovery of the fixed cost of networks. However, when prosumers buy electricity from the market (z_{it}^b >0, z_{it}^s=0), prosumers face $p_{it}+\tau_b$ with τ_b >0 as a transmission tariff in a similar manner to the consumers. From this optimization problem, we can derive the following KKT conditions:

$$0 \leq z_{it}^{s} \perp (p_{it} + \tau^{s} - \delta_{it})B_t \leq 0, \forall i, \forall t \tag{3.16}$$

$$0 \leq z_{it}^{b} \perp (-p_{it} - \tau^{b} + \delta_{it})B_t \leq 0, \forall i, \forall t \tag{3.17}$$

$$0 \leq l_{it} \perp \left(P_{it}^{0} - \frac{P_{it}^{0}}{\alpha_i Q_{it}^{0}} l_{it} - \delta_{it} \right) B_t \leq 0, \forall i, \forall t \tag{3.18}$$

$$0 \leq g_{it} \perp \left(-C_i^{g'}(g_{it}) + \delta_{it} - \kappa_{it} \right) B_t \leq 0, \forall i, \forall t \tag{3.19}$$

$$0 \leq k_i \perp -E + \sum_t CF_t \delta_{it} B_t \leq 0, \forall i \tag{3.20}$$

$$0 \leq \delta_{it} \perp (z_{it}^{s} - z_{it}^{b} + l_{it} - CF_t k_i - g_{it})B_t \leq 0, \forall i, \forall t \tag{3.21}$$

$$0 \leq \kappa_{it} \perp (g_{it} - G_i)B_t \leq 0, \forall i, \forall t \tag{3.22}$$

From Eqs. (3.16) and (3.17), the prosumer electricity consumption l_{it} for each period is determined such that the marginal benefit is equal to the retail price, that is, $p_{it} + \tau_s$, when they sell energy, or $p_{it} + \tau_b$, when they purchase energy.

3.3.3 ISO

We assume that the ISO is an entity that balances short-term energy supply and demand given existing transmission facilities. The ISO maximizes the social surplus by determining the amount of producer electricity generation x_{iht} from unit h, the amount of consumer electricity consumption, d_{it}, and the amount of electricity injection/withdrawal y_{it}, at each node and each period. The ISO objective function, Eq. (3.23), consists of the benefits from consumer electricity consumption and the cost of the producer electricity generation $C_{ih}(x_{iht})$. Thus, the ISO optimization problem can be written as follows:

$$\underset{x_{iht},d_{it}\geq 0,y_{it}}{\text{maximize}} \quad \sum_{i,t}\left(\int_0^{d_{it}} p_{it}(n_{it})dn_{it}\right)B_t - \sum_{i,h,t} C_{ih}(x_{iht})B_t \tag{3.23}$$

subject to

$$(x_{iht} - X_{ih})B_t \leq 0 \qquad (\rho_{iht}) \tag{3.24}$$

$$\sum_i y_{it}B_t = 0, t \in T \qquad (\theta_t) \tag{3.25}$$

$$\left(\sum_i PTDF_{si}y_{it} - T_s\right)B_t \leq 0 \qquad (\lambda^+_{st}) \tag{3.26}$$

$$\left(-\sum_i PTDF_{si}y_{it} - T_s\right)B_t \leq 0 \qquad (\lambda^-_{st}) \tag{3.27}$$

Eq. (3.24) is a constraint on the generation capacity X_{ih}. Eq. (3.25) ensures that the electricity injection/withdrawal among nodes is balanced. Furthermore, Eqs. (3.26) and (3.27) ensure that the power flow of link s does not exceed the transmission capacity T_s, considering the power transfer distribution factors. We also add the following constraints to the overall nodal balance in each period:

$$\left(y_{it} - \sum_h x_{iht} - z_{it} + d_{it}\right)B_t = 0, \qquad (p_{it}) \tag{3.28}$$

$$\left(y_{it} - \sum_h x_{iht} - (z^s_{it} - z^b_{it}) + d_{it}\right)B_t = 0, \qquad (p_{it}) \tag{3.29}$$

Eq. (3.28) and Eq. (3.29) represent the constraints on the nodal balance satisfied under net metering and net billing, respectively. These constraints show that the nodal balance of electricity supply and demand is satisfied by the amount of electricity injection/withdrawal, producer electricity generation, prosumer sales/purchases, and consumer electricity consumption. From the ISO optimization problem, the

KKT conditions for the ISO can be derived as follows:

$$0 \leq d_{it} \perp \left(P_{it}^0 - \frac{P_{it}^0}{((1-\alpha_i)Q_{it}^0)} d_{it} - (p_{it} + \tau) \right) B_t \leq 0, \forall i, \forall t \tag{3.30}$$

$$0 \leq d_{it} \perp \left(P_{it}^0 - \frac{P_{it}^0}{((1-\alpha_i)Q_{it}^0)} d_{it} - (p_{it} + \tau^b) \right) B_t \leq 0, \forall i, \forall t \tag{3.31}$$

$$0 \leq x_{iht} \perp \left(-C_{ih}^{'}(x_{iht}) - \rho_{iht} + p_{it} \right) B_t \leq 0, \forall i, \forall t, h \in H_i \tag{3.32}$$

$$\left(-\theta_t + \sum_s PTDF_{si} \left(\lambda_{st}^- - \lambda_{st}^+ \right) - p_{it} \right) B_t = 0, \forall i, \forall t \tag{3.33}$$

$$0 \leq \rho_{iht} \perp (x_{iht} - X_{i,h}) B_t \leq 0, \forall i, \forall t, h \in H_i \tag{3.34}$$

$$\sum_i y_{it} B_t = 0, \forall t \tag{3.35}$$

$$0 \leq \lambda_{st}^+ \perp \left(\sum_i PTDF_{si} y_{it} - T_k \right) B_t \leq 0, \forall s, \forall t \tag{3.36}$$

$$0 \leq \lambda_{st}^- \perp \left(-\sum_i PTDF_{si} y_{it} - T_k \right) B_t \leq 0, \forall s, \forall t \tag{3.37}$$

$$\left(y_{it} - \sum_h x_{iht} - z_{it} + d_{it} \right) B_t = 0, \forall i, \forall t \tag{3.38}$$

$$\left(y_{it} - \sum_h x_{iht} - (z_{it}^s - z_{it}^b) + d_{it} \right) B_t = 0, \forall i, \forall t \tag{3.39}$$

Eq. (3.30) is the condition for net metering, whereas Eq. (3.31) is for net billing. These conditions mean that consumers make decisions on the amount of electricity consumption d_{it} facing the retail price, $p_{it} + \tau$ in net metering and $p_{it} + \tau_b$ in net billing.

3.3.4 Transmission cost recovery

Finally, we consider the constraint on transmission cost recovery. Transmission owners need to impose a transmission tariff on consumers and prosumers to recover the fixed cost of investment and maintenance of transmission lines.[8] The constraint

[8] Transmission owners commission the ISO to operate and manage their transmission facility.

on each pricing scheme is expressed as follows:

$$\tau \sum_{i,t} \left(-z_{it} + d_{it}\right) B_t = R, \tag{3.40}$$

$$\sum_{i,t} \left(-z_{it}^s \tau^s + z_{it}^b \tau^b + d_{it} \tau^b\right) B_t = R \tag{3.41}$$

Eq. (3.40) is a constraint on the transmission cost recovery in net metering. On the one hand, in the case of prosumers selling electricity (z_{it} >0), the transmission tariff is imposed on consumer electricity consumption minus the amount of prosumer electricity sales. On the other hand, in the case of prosumers buying electricity (z_{it} <0), the transmission tariff is imposed on the amount of prosumer electricity purchases in addition to the amount of consumer electricity consumption. Hence, if z_{it} >0, only the consumer bears the transmission tariff, and if z_{it} <0, both consumers and prosumers bear the transmission tariff. Eq. (3.41) is the constraint on transmission cost recovery in net billing. In the case of prosumers buying electricity from the market (z_{it}^b >0, $z_{it}^s = 0$), on the one hand, the fixed cost is recovered by imposing the transmission tariff on consumer electricity consumption and prosumer electricity purchases, as in net metering. On the other hand, in the case of prosumers selling electricity to the market (z_{it}^b =0, z_{it}^s >0), τ_s works differently depending on whether it is positive or negative. If τ_s >0, τ_s acts as a subsidy for prosumer sales. Therefore, the subsidy for the amount of prosumer sales is deducted from the consumer tariff payment. If τ_s <0, it acts as a tariff for prosumer sales, which is added to the consumer tariff payment.

Finally, the collection of KKT conditions for all market participants along with the constraint on fixed cost recovery defines the market equilibrium problem under net metering, that is, Eqs. (3.7)–(3.12), Eq. (3.30), Eqs. (3.32)–(3.38), and Eq. (3.40). The market equilibrium problem under net billing is expressed by Eqs. (3.16)–(3.22), Eqs. (3.31)–(3.37), Eqs. (3.39), and (3.41).

3.4 Qualitative analysis

In this section, we characterize each pricing scheme in terms of prosumer decision-making.

3.4.1 Net metering

Since Eq. (3.5) holds as an equality, that is, $z_{it} = -l_{it} + CF_t k_i + g_{it}$ in equilibrium, we can rewrite the prosumer objective function in Eq. (3.4) in net metering as follows:

$$\sum_t (p_{it} + \tau)\left((CF_t k_i + g_{it}) - l_{it}\right) B_t \qquad + \sum_t \left(\int_0^{l_{it}} p_{it}^{pro}(m_{it}) dm_{it}\right) B_t$$
$$- \sum_t C_i^g(g_{it}) B_t - E k_i \qquad (3.42)$$

Eq. (3.42) indicates that the prosumers under the net metering scheme face the price of $p_{it} + \tau$ for their electricity generation as well as consumption. Thus, the prosumers value their electricity generation at a subsidized price $p_{it} + \tau$, which is higher than the price p_{it} for producer electricity generation. As prosumers under the net metering scheme virtually receive subsidies for electricity sales, they would tend to increase their investment in the capacity of PVs k_i and increase the difference between electricity power generation and consumption, that is, $(CF_t k_i + g_{it}) - l_{it}$, even if it incurs an additional investment cost. This implies that net metering promotes greater prosumer investment and electricity sales.

3.4.2 Net billing

Similarly, Eq. (3.14) holds as an equality, that is, $z_{it}^s - z_{it}^b + l_{it} - CF_t k_i - g_{it} = 0$ in equilibrium under net billing. We divide into two cases because the prosumers in net billing face different prices when buying (z_b >0, z_s=0) and selling (z_b=0, z_s >0). First, in the case of prosumers buying electricity (z_b >0, z_s=0), the prosumer objective function, Eq. (3.13), can be rewritten using $z_{it}^{b} = l_{it} - CF_t k_i - g_{it}$ as follows:

$$\sum_t (p_{it} + \tau^b)\left((CF_t k_i + g_{it}) - l_{it}\right) B_t \qquad + \sum_t \left(\int_0^{l_{it}} p_{it}^{pro}(m_{it}) dm_{it}\right) B_t \\ - \sum_t C_i^g(g_{it}) B_t - Ek_i \qquad (3.43)$$

In this case, prosumers evaluate both electricity generation and consumption when facing $p_{it} + \tau_b$, similar to the case of net metering. Here, prosumers and consumers face the same retail price when purchasing electricity. Next, we consider the case whereby prosumers sell electricity (z_b =0, z_s >0). The prosumer objective function, Eq. (3.13), in net billing can be rewritten using $z_{it}^{s} = -l_{it} + CF_t k_i + g_{it}$ as follows:

$$\sum_t (p_{it} + \tau^s)\left((CF_t k_i + g_{it}) - l_{it}\right) B_t \qquad + \sum_t \left(\int_0^{l_{it}} p_{it}^{pro}(m_{it}) dm_{it}\right) B_t \\ - \sum_t C_i^g(g_{it}) B_t - Ek_i \qquad (3.44)$$

From Eqs. (3.43) and (3.44), the prosumer objective function under the net billing scheme coincides with that under net metering when $\tau_s = \tau_b$. However, in practice, τ_s can take any value ranging from positive to negative, and prosumers may face different prices for sales and purchases in net billing. For example, suppose that $\tau_s = -0.5\tau_b$, where prosumers are imposed tariff for electricity sales. Then, prosumers evaluate their electricity generation at a price lower than the producer selling price by $0.5\tau_b$, while they face a lower price than consumers for their consumption. Hence, it implies that net billing discourages prosumer investment and encourages consumption when tariffs are imposed on electricity sales.

3.5 Numerical case study

3.5.1 Data and setting

In this study, we assume ten generating units (1,2,$\cdots$,10), three nodes (a, b, c), and three transmission lines with loop flow, similar to the setting of Chen et al. (2011, 2020). Chen et al. assume that the three nodes consist of California with large electricity demand, and northwest and southwest states with relatively low electricity demand. Corresponding to their setting, we assume that node a is the region of high demand, and nodes b and c are the regions of relatively low demand. Fig.3.1 illustrates the nodes and networks for the numerical case study. In addition, we assume that prosumers exist only at node a, invest in PVs to generate electricity, and operate the battery storage. P_0 and Q_0 are obtained by solving the cost minimization linear programming in multiple regions using the data from Chen et al. (2011, 2020). We divide the load into peak, mid-peak, and off-peak (Denholm, 2007; Mallapragada et al., 2018). The PV capacity factor for each period is based on Boretti et al. (2020), Pfrenninger (2017), and Palmer (2013). The primary parameters are presented in Appendix C. The annualized capital cost of solar PV panels is assumed range from the current level of 100,000 \$/MW-year to the future level of 60,000 \$/MW-year in anticipation of cost reductions based on Gorman (2020) and Taylor et al. We refer to Woo et al. (2003) and Pfeifenberger (2011) for the fixed cost of transmission and assume 70,080,000 \$/year.

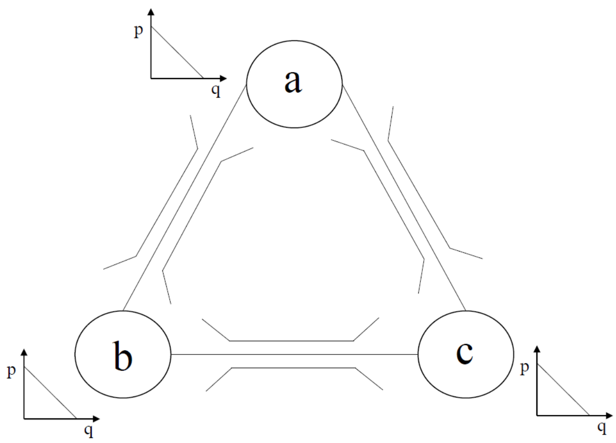

Figure 3.1: Nodes and networks for numerical case study

Next, we describe the data related to battery operation. The discharging and charging efficiencies of the battery storage are set to 0.95, (Avau et al., 2021). We assume that the battery storage can be used between 20% and 80% of the battery capacity, that is, the lower (upper) limit of usable capacity as the ratio to battery capacity is set to 0.2 (0.8), while the self-discharge rate is assumed to be 0 based on Long et al. (2018). The rate of discharge and charge allowance per hour for battery capacity is set to 0.25 (Avau et al., 2021; L ü th et al., 2018). The annualized capital cost of battery storage is assumed to be 120,000$/MW-year (Cole and Frazier, 2019; Ralon et al., 2017). We assume 4 hours for the peak, 9 hours for the mid-peak, and 11 hours for the off-peak periods in a day. In addition, we assume a chronological order of the mid-peak (t =1), peak (t =2), and off-peak (t =3) periods.

Lastly, we assume that $\tau_s = -0.5\tau_b$ in net billing, which implies that a tariff is imposed on prosumers for their electricity sales. We conduct the analysis using solver, PATH, which can handle the complementarity problem.

3.5.2 Main results

We vary the capital cost of solar PV panels to determine the impact on the outcome, focusing on the case where the fraction of prosumers is $\alpha_A = 0.5$.[9] In this section, we assume that prosumers invest in PVs without considering battery operation.

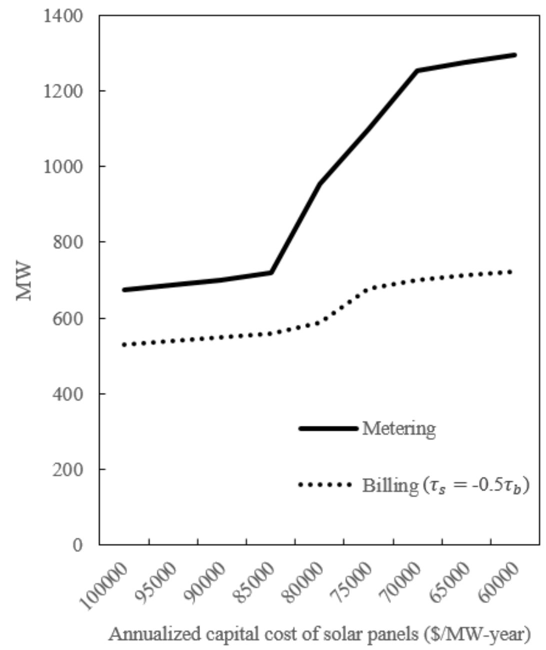

Figure 3.2: Capacity of PVs invested by prosumers

First, we present the results for the PV capacity invested by prosumers. Fig. 3.2 shows that the PV capacity tends to increase as the capital cost of PVs decreases under both pricing schemes. In addition, the capacity of PVs in net metering is larger than that under net billing for all ranges of capital costs of PVs. Prosumers under net metering invest in a larger capacity and sell more electricity because τ acts as a subsidy for electricity sales. Conversely, prosumers under net billing have less incentive to sell electricity and decide to invest in a smaller PV capacity because the

[9]Varying the fraction of prosumers from α_i=0.1 to α_i=0.9 yields generally similar results and implications.

tariff is imposed for electricity sales. Thus, the difference in tariff structure affects prosumer investment decision. Notably, the PV capacity sharply rises between the PV capital costs of 85,000$/MW-year and 70,000$/MW-year. Prosumers gradually increase their investment and electricity sales from low-cost PV generation until the capital cost of PV decreases to about 85,000$/MW-year. Correspondingly, the wholesale price decreases gradually in this range. Subsequently, when the capital cost of PV reaches about 85,000$/MW-year, the wholesale price becomes lower than the marginal cost of some generating units in the case of net metering, which makes producers sharply reduce their electricity supply by changing the operation of some generating units. This producers' decision steeply raises the retail price through a high transmission tariff (See Fig. 3.3), and in turn, prosumers respond by sharply increasing their investment between the PV capital costs of 85,000$/MW-year and 70,000$/MW-year.

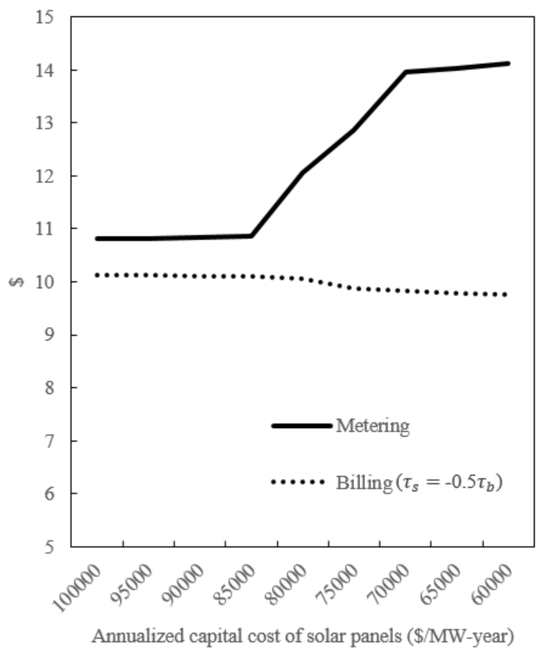

Figure 3.3: Transmission tariff

Fig. 3.3 shows the result for the transmission tariff. In the case of net metering, the decrease in the capital cost of PVs increases the capacity of PVs, and consequently, the amount of prosumer electricity sales, whereas the amount of producer electricity supply declines. The decrease in the producer electricity supply leads to the rise in the transmission tariff, as alluded to by $\tau \sum_{i,h,t} x_{iht} B_t = R$. [10] Consequently, the transmission tariff becomes higher when the capital cost of PVs decreases under net metering. However, in net billing, prosumers sell much less electricity compared to the case of net metering, especially when the capacity of PVs is smaller, as shown in Figs. 3.4 and 3.5. Thus, the impact of prosumer electricity sales on producer electricity supply is relatively small. Therefore, the transmission tariff in net billing is lower than that under net metering, even declining slightly as the capital cost of PVs decrease.

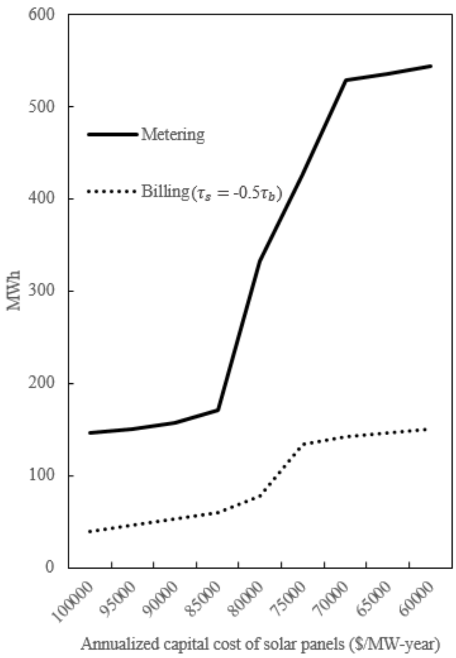

Figure 3.4: Prosumer electricity sales(+) or purchases(-) in peak

Next, Fig. 3.4 shows the result of prosumer electricity sales or purchases in peak.

[10] Summing Eq. (3.28) for node i, we obtain $\left(\sum_i y_{it} - \sum_{i,h} x_{iht} - \sum_i z_{it} + \sum_i d_{it}\right) B_t = 0$. Here, the term for y_{it} is zero from Eq. (3.25); thus, we can rewrite it as $\sum_{i,h} x_{iht} B_t = \left(-\sum_i z_{it} + \sum_i d_{it}\right) B_t$. Furthermore, summing this up for t, we can express it as $\sum_{i,h,t} x_{iht} B_t = \sum_{i,t} \left(-z_{it} + d_{it}\right) B_t$. By substituting this into Eq. (3.40), we obtain $\tau \sum_{i,h,t} x_{iht} B_t = R$.

Prosumers in both pricing schemes sell electricity to the market at all ranges of the capital cost of PVs owing to the large capacity factor in the peak period. Prosumers under net metering sell more electricity with a larger PV capacity than net billing.

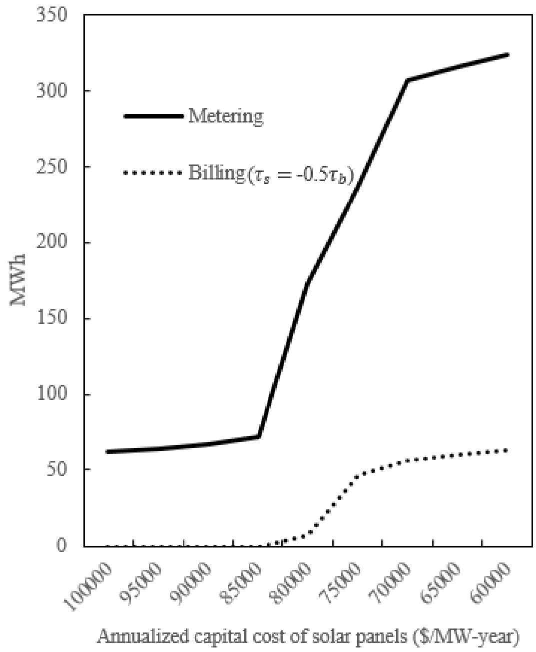

Figure 3.5: Prosumer electricity sales(+) or purchases(-) in mid peak

Prosumers in net metering also sell electricity at the mid-peak, as indicated in Fig. 3.5. Because of the lower capacity factor in the mid-peak period, prosumer sales are lower than those in the peak period in all ranges of the PV capital cost. A similar observation emerges for net billing, where prosumers use up the capacity of PVs entirely for their electricity consumption without selling excess electricity in the range of the high capital cost of PVs. If the capital cost of PVs declines sufficiently, then prosumers in net billing sell excess electricity utilizing the larger capacity of PVs.

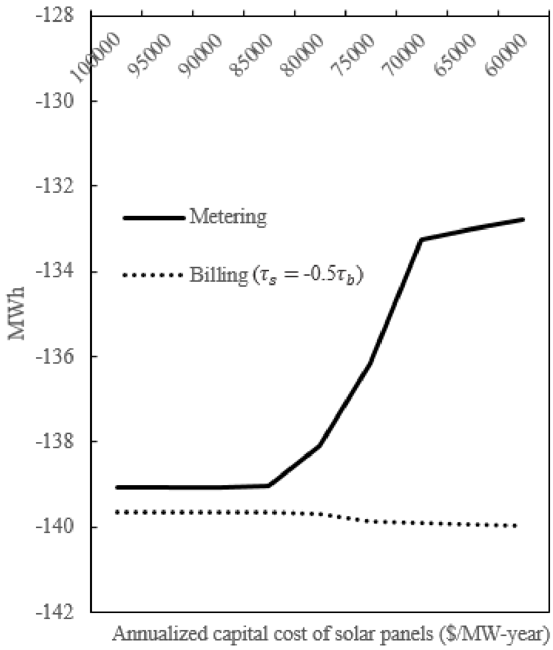

Figure 3.6: Prosumer electricity sales(+) or purchases(-) in off peak

As shown in Fig. 3.6, prosumers buy electricity from the market since the capacity factor is zero in the off-peak period. The prosumer electricity purchases at the off-peak period in Fig. 3.6 are consistent with the levels of the transmission tariff in Fig. 3.3. Prosumers purchase less electricity when the transmission tariff is higher.

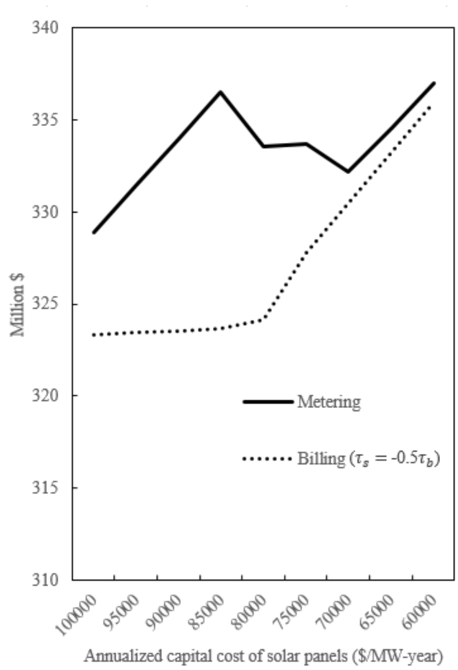

Figure 3.7: Annual consumer surplus

Fig. 3.7 presents the result of annual consumer surplus, which is affected by the retail prices, $p_{it} + \tau$ in net metering and $p_{it} + \tau_b$ in net billing. Particularly, increases in the transmission tariff have an upward pressure on the retail prices, whereas decreases in the wholesale prices owing to low-cost generation by PVs suppress the retail prices. The consumer surplus in net metering increases in the range of the higher capital cost of PVs. This is because the level of transmission tariff is stable (see Fig. 3.3), while the wholesale price decreases sufficiently. Subsequently, the consumer surplus decreases due to the rapid increase in the transmission tariff in the range of the lower capital cost of PVs (see Fig. 3.3). As the capital cost of PVs is further reduced, the consumer surplus tends to increase again as the level of the transmission tariff becomes stable (see Fig. 3.3). In the case of net billing, the fluctuation of the transmission tariff is limited, as in Fig. 3.3, while the wholesale price gradually decreases. Thus, the consumer surplus in net billing rises as the capital cost of PVs decreases. Comparing the results between these two pricing schemes, the consumer surplus in net metering is larger than that in net billing for all levels of capital costs of PVs.

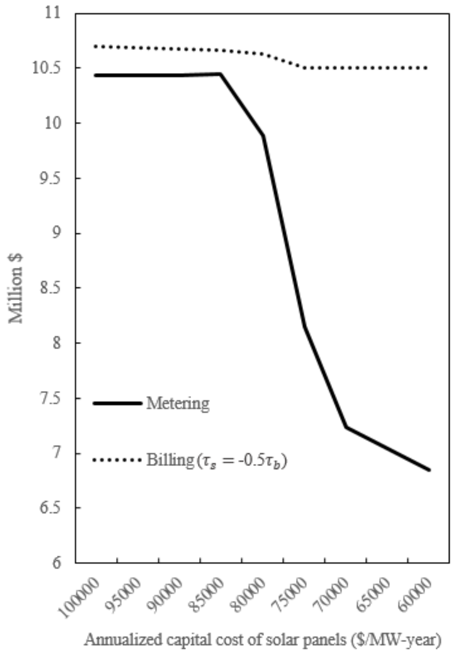

Figure 3.8: Annual producer surplus

Fig. 3.8 shows the result of the annual producer surplus. Producers reduce their electricity supply since prosumers sell more electricity to the market with larger investments as the capital cost of PVs decreases. Consequently, the producer surplus decreases as the capital cost of PVs is reduced. The case of net billing, where prosumer investment and electricity sales are relatively small, has less impact on producer electricity supply, thereby resulting in a high producer surplus. Conversely, the producer surplus in net metering is less since the prosumer investment and electricity sales are larger. Particularly, the producer surplus in net metering falls sharply as the capital cost of PVs decreases, corresponding to the sharp rise in prosumer electricity sales.

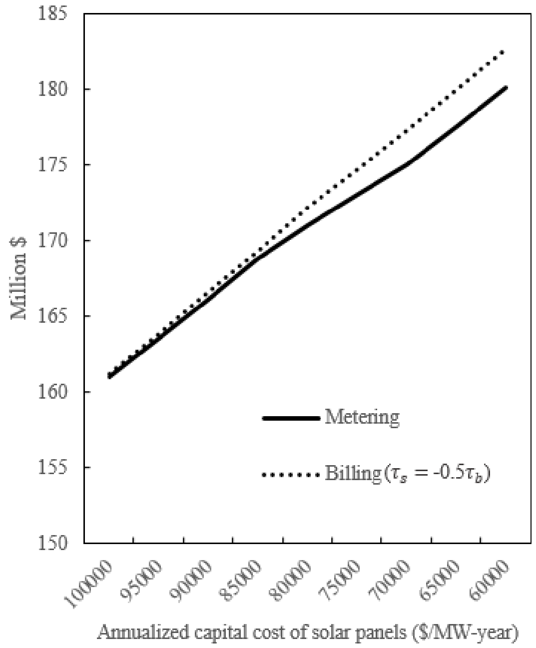

Figure 3.9: Annual prosumer surplus

As shown in Fig. 3.9, the prosumer surplus increases as the capital cost of PVs decreases. Comparing the two pricing schemes, the prosumer surplus in net metering is smaller than that in net billing for all levels of the capital cost of PVs, even though prosumers under the net metering scheme receive subsidies. The result also shows that the difference in prosumer surplus between the pricing schemes widens as the capital cost of PVs falls. Prosumers in net metering decide to increase the capacity of PV and sell electricity to obtain a large surplus at the peak and mid-peak periods, while they cannot expand their surplus when purchasing electricity in the off-peak period because of the higher retail price with higher transmission tariff. Contrarily, prosumers in net billing cannot attain as large a surplus as net metering at the peak and mid-peak periods because they have less PV capacity, while they can enjoy a relatively large surplus when buying electricity in the off-peak period because of the lower retail price with a lower transmission tariff. Overall, the prosumer surplus in net metering is smaller than that in net billing, despite receiving subsidies for electricity, which may be counterintuitive. Note that our result may be affected by the fact that approximately half of the time in a year is an off-peak period for solar PV generation. To check the robustness of our results, we conduct an additional analysis, as described in Section 3.5.3, for the case where the prosumers operate battery storage, charging and discharging across all periods.

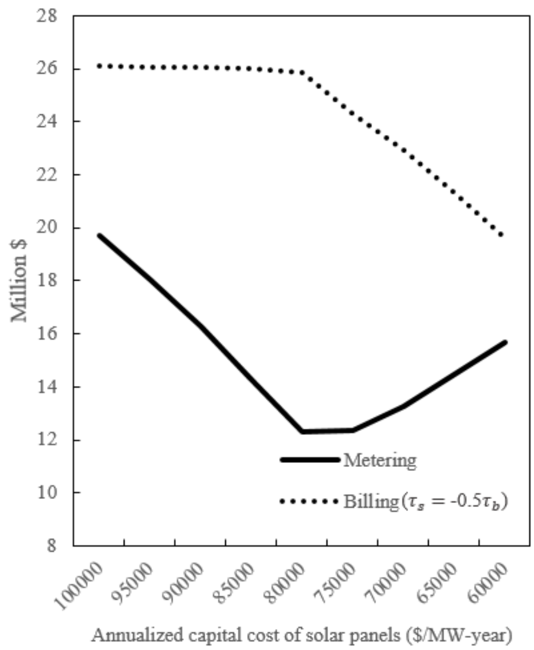

Figure 3.10: Annual ISO surplus

The results for the ISO surplus are presented in Fig. 3.10. By operating electricity injection/withdrawal, the ISO obtains the surplus, sometimes called the merchandising surplus, which is attributed to the price differences between nodes (Chao and Peck, 1996). [11] Upon comparing pricing schemes, the price differences are larger under net billing than under net metering on average. Thus, the ISO surplus in net billing is greater than that in net metering.

[11] We define the annual ISO surplus as $\sum_{i,t}(ph_t - p_{it})y_{it}B_t$ in this study. Here, ph_t is the price in the hub of period t, which is defined as $ph_t = p_{it}$ by selecting an arbitrary node i as the hub from set I.

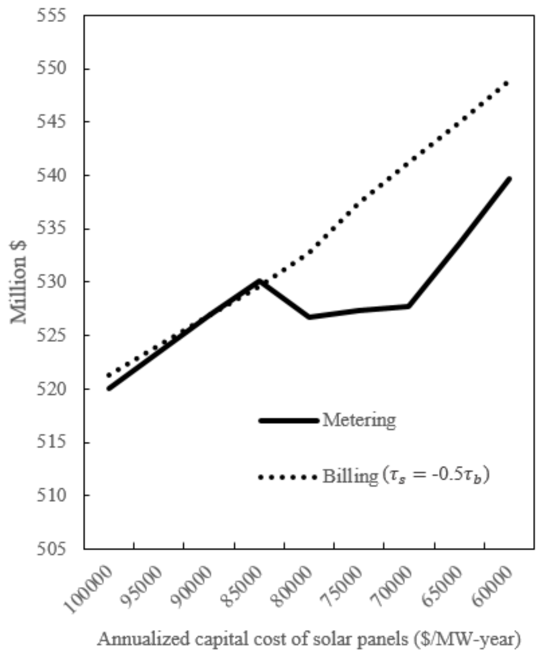

Figure 3.11: Total social surplus

Finally, we present the results for the total social surplus in Fig. 3.11. The total social surplus is expressed as the sum of the producer surplus, consumer surplus, prosumer surplus, and ISO surplus. Overall, the results indicate that the total social surplus tends to increase as the capital cost of PVs decreases. This result can be attributed mainly to the impact of the prosumer surplus and consumer surplus, which tend to increase as the capital cost of PVs decreases. The total social surplus in net metering and net billing is almost the same in the range of the high capital cost of PVs. However, the total social surplus in net billing becomes much larger than that in net metering when the capital cost of PVs is further reduced because the consumer surplus in net metering decreases sharply within a certain range of the capital cost of PVs, as depicted in Fig. 3.7. Our results suggest that providing subsidies to prosumers through net metering may be inferior in terms of total social surplus compared to imposing a tariff on prosumer electricity sales through net billing. Moreover, our results imply that policies to reduce RE investment costs may be relevant to improve the social surplus.

3.5.3 Result with battery storage

As discussed in the previous section, prosumers with PV may generate more electricity than they consume, selling excess electricity during peak and mid-peak periods, whereas they cannot generate electricity during the off-peak period. If prosumers own battery storage, they may store electricity during the peak and mid-peak period to use it during the off-peak period. To consider such a behavior, we conduct an additional analysis by including the prosumer battery operation in this section. Here, we assume exogenous battery capacity to avoid complicating the problem because this study focuses on prosumer investment decisions in PVs. The details of the prosumer optimization problem with battery operation are described in Appendix B. We compare the results between the pricing schemes with $\alpha_A = 0.5$, as in the previous section, focusing on the cases of the capital cost of solar PV panels of 100,000\$/MW-year and 60,000\$/MW-year. We assume a battery capacity of W_i=0MW(Without), 300MW, and 600MW.

Table 3.1: Comparison of the main results under net metering with and without battery operation (The capital cost of solar PV panels : 100,000$/MW-year)

Variables\Cases	Without	300MW	600MW
Prosumer investment in PV (MW)	675.37	704.63	732.29
Transmission tariff ($/MWh)	10.82	10.94	11.08
Prosumer surplus (Million $)	160.99	125.66	89.99
Consumer surplus (Million $)	328.89	328.78	328.34
Producer surplus (Million $)	10.43	10.33	10.24
ISO surplus (Million $)	19.70	18.83	18.64
Total social surplus (Million $)	520.01	483.60	447.11

Table 3.2: Comparison of prosumer decision under net metering with and without battery operation (The capital cost of solar PV panels : 100,000$/MW-year)

Variables/Cases and Periods	Without			300MW			600MW		
	Mid peak	Peak	Off peak	Mid peak	Peak	Off peak	Mid peak	Peak	Off peak
Prosumer consumption (MWh)	241.93	326.36	139.08	245.66	319.35	139.21	245.66	319.35	139.33
Prosumer sales (+) or purchases (-) (MWh)	61.98	146.40	-139.08	65.70	139.40	-123.66	65.70	139.40	-108.24
Charge (+) or Discharge (-) (MWh)	-	-	-	5.72	34.49	-15.55	18.17	53.85	-31.09
Battery capacity in use at the end of period (MW)	-	-	-	108.94	240	60	275.37	480	120

First, we present the result for the net metering case, where the capital cost of solar PV panels is 100,000$/MW-year. Table 3.1 shows the main numerical results for the capacity of PVs invested by prosumers, transmission tariffs, and the surplus of each market participant. Table 3.2 presents the numerical results for the prosumer decision-making in each period. As indicated in Table 3.1, an increase in the prosumer battery capacity leads to an increase in the prosumer PV capacity. This can be attributed to the flexibility to charge/discharge electricity using larger PVs and battery storage. In addition, as shown in Table 3.2, the battery operation affects the prosumer decision-making in each period. In the mid-peak period, prosumers raise electricity consumption and sales, while storing excess electricity in battery storage. In the peak period, electricity consumption and sales decline, while storing electricity up to the upper limit of the usable battery capacity. Thereafter, they increase the electricity consumption during the off-peak, consuming the electricity stored during the mid-peak and peak periods, along with additional electricity purchased from the market. The electricity stored during the mid-peak and peak periods is used up to the lower limit of the usable battery capacity at the end of the off-peak period. Consequently, the transmission tariff increases slightly because prosumers buy less electricity from producers as the battery capacity increases. Table 3.1 also shows that the impact on the surplus of each market participant is limited, except for the prosumers, of which the surplus decreases significantly. This, in turn, leads to a reduction in the total social surplus when the prosumers own the battery storage.[12]

Table 3.3: Comparison of the main results under net billing with and without battery operation (The capital cost of solar PV panels : 100,000$/MW-year)

Variables\Cases	Without	300MW	600MW
Prosumer investment in PV (MW)	530.48	535.94	564.57
Transmission tariff ($/MWh)	10.13	10.28	10.39
Prosumer surplus (Million $)	161.14	125.93	90.27
Consumer surplus (Million $)	323.36	322.34	321.84
Producer surplus (Million $)	10.70	10.67	10.58
ISO surplus (Million $)	26.09	26.03	25.83
Total social surplus (Million $)	521.30	484.97	448.53

Table 3.4: Comparison of prosumer decision under net billing with and without battery operation (The capital cost of solar PV panels : 100,000$/MW-year)

Variables/Cases and Periods	Without			300MW			600MW		
	Mid peak	Peak	Off peak	Mid peak	Peak	Off peak	Mid peak	Peak	Off peak
Prosumer consumption (MWh)	238.71	332.41	139.65	241.17	327.79	139.74	245.67	319.35	139.88
Prosumer sales (+) or purchases (-) (MWh)	0	38.92	-139.65	0	0	-124.20	0	0	-108.79
Charge (+) or Discharge (-) (MWh)	-	-	-	0	47.37	-15.55	8.40	75.84	-31.09
Battery capacity in use at the end of period (MW)	-	-	-	60	240	60	191.80	480	120

Next, Tables 3.3 and 3.4 display the results for the net billing case. Table 3.3 indicates that the PV capacity increases with the battery capacity, similar to the net metering case. In the analysis in the previous section, prosumers sell excess electricity in the peak period with a high capacity factor. However, the introduction of the battery storage allows prosumers to store excess electricity during the peak period. Table 3.4 shows that the prosumers neither sell nor buy during the mid-peak and peak periods, and they charge the battery storage with excess electricity up to the upper limit. Thereafter, they consume the electricity stored in the battery storage up to the lower limit during the off-peak period. The transmission tariff

[12] If we ignore the capital cost of the battery storage, the prosumer surplus increases. This is because the capital cost of the battery storage is substantially high at the current level.

increases slightly, as shown in Table 3.3, because the prosumers reduce the electricity purchase from the producers as the battery capacity increases, which is the same as the net metering case. Similar to the results of net metering, Table 3.3 depicts that the impact on market participants other than the prosumer is small.

Furthermore, comparing Tables 3.1 and 3.3, the total social surplus in net billing is larger than that in net metering for both cases with the battery storage (W_i=300MW, 600MW). These results suggest that net billing yields a larger social surplus than net metering, which is consistent with the results of Section 3.5.2.

Table 3.5: Comparison of the main results under net metering with and without battery operation (The capital cost of solar PV panels : 60,000$/MW-year)

Variables\Cases	Without	300MW	600MW
Prosumer investment (MW)	1295.00	1357.25	1422.96
Transmission tariff ($/MWh)	14.11	14.65	15.29
Prosumer surplus (Million $)	180.17	146.23	112.19
Consumer surplus (Million $)	336.98	334.98	332.33
Producer surplus (Million $)	6.85	6.49	6.36
ISO surplus (Million $)	15.65	15.50	15.46
Total social surplus (Million $)	539.65	503.20	466.34

Table 3.6: Comparison of the main results under net billing with and without battery operation (The capital cost of solar PV panels : 60,000$/MW-year)

Variables\Cases	Without	300MW	600MW
Prosumer investment (MW)	723.92	753.20	780.42
Transmission tariff ($/MWh)	9.75	9.84	9.93
Prosumer surplus (Million $)	182.74	148.57	113.95
Consumer surplus (Million $)	335.95	335.88	335.36
Producer surplus (Million $)	10.51	10.41	10.32
ISO surplus (Million $)	19.62	18.75	18.60
Total social surplus (Million $)	548.82	513.61	478.23

The results for the cases whereby the capital cost of solar PV panels is 60,000$/MW-year are summarized in Tables 3.5 and 3.6. These results are similar to those whereby the capital cost of solar PV panels is 100,000$/MW-year. The total social surplus in net billing is greater than that in net metering, and the difference is even larger between the two pricing schemes compared to Tables 3.1 and 3.3.

We find that a greater total social surplus is achieved via net billing, even when considering the prosumer battery operation. These results are consistent with those of Section 3.5.2, which suggests that our findings are rather robust.

3.6 Conclusion

This study examined the decision-making of prosumers in the electricity market under net metering and net billing schemes. We formulated the complementarity problem to analyze the behavior of market participants, considering prosumer investment in PVs, network with loop flow, pricing schemes for prosumers, and fixed cost recovery of the grid. We compared the market outcomes, such as the capacity of PVs, transmission tariffs, and social surplus, under the two pricing schemes. In addition, we analyzed the case whereby the prosumers operate battery storage.

On the one hand, the results show that prosumers in net metering decide to sell their electricity by investing in a larger PV capacity. This prosumer decision-making leads to an increase in the transmission tariff, which affects the surplus of other market participants. On the other hand, prosumers in net billing tend to invest in less PV capacity than that in net metering and cover their electricity consumption with their generation. This results in less sales by prosumers and a smaller impact on transmission tariffs. Comparing the two pricing schemes, the total social surplus in net metering and net billing is approximately the same for a high PV capital cost. However, if the capital cost of PVs is sufficiently reduced, the total social surplus in net billing becomes much larger than that in net metering because the consumer surplus in net metering decreases significantly with a sharp rise in the transmission tariff. The result that net billing is superior to net metering in terms of social surplus is also established when considering prosumer battery operation. This suggests that net billing could be a better regulatory scheme in the future, especially when the capital cost of PVs falls sufficiently.

Future research could include a variety of additional analyses, such as prosumers existing at multiple nodes, investments in other RE sources, and implementation of other pricing schemes. Furthermore, the battery capacity could be treated as an endogenous decision variable, anticipating that the capital cost of battery storage will significantly decrease in the future.

Chapter 4

Summary and policy implications

The findings of this study raise issues related to the future RE policy formulation, given that the contribution of the electricity market is necessary to the addressing of both the increasing energy demand and decarbonization. RE policy formulation becomes increasingly important for decisions regarding further investment in RE while addressing problems such as RE investment cost and fixed cost recovery of networks. In that sense, participants in the electricity market are now required to make unprecedented decisions, including decisions regarding investment in RE and networks, in the context of the restructuring of the electricity market and RE policy. Notably, this study focused on FIP, net billing, and net metering as well as the potential for the installation cost reduction of RE. We analyzed RE investment decisions by electricity market participants and social surplus under RE policies, and provided evaluation and suggestions about these policies.

First, we combined the real options approach and game theory to develop models of the investment decision-making of GENCO and TSO under vertical unbundling. We analyzed investment timing, capacity, and social surplus in three scenarios where GENCO and TSO invested separately in generation and transmission capacity: investment in RE with FIP (L-W-FIP); investment in RE with its cost reduction (L-W-Cost); and investment in NRE (L-L). We observed that FIP and installation cost reduction of RE affect the decision-making of the GENCO and TSO differently. Specifically, we found that FIP significantly affects the capacity, while installation cost reduction of RE significantly affects the investment timing. Social surplus is larger in both L-W-FIP and L-W-Cost scenarios than that under the L-L scenario. That result suggests that both FIP and installation cost reduction of RE affected social surplus through investment timing and capacity; at the same time, increased environmental tax and damage cost significantly reduced the social surplus in the L-L scenario and widened the difference in social surplus. Moreover, comparing the L-W-FIP scenario and the L-W-Cost scenario, we observed that the L-W-FIP scenario gives rise to a social surplus larger than the L-W-Cost scenario at the current level of RE installation cost. Later, in the transition period with RE installation cost reduction, we observed that FIP could generate a large social surplus in the range of higher uncertainty, while the installation cost reduction of RE generates a large social surplus without FIP in the range of lower uncertainty. We also observed that in the transition period, the decision as to whether to implement FIP or not should be made depending on the degree of uncertainty. Finally, we found that if the installation cost reduction of RE is near the same level as the installation cost of NRE, a large social surplus can be obtained without implementing FIP for all degrees of uncertainty, and still controlling the financial burden. This suggests that policies to induce the RE investment cost reduction may become more critical in the future.

Next, we examined the effectiveness of net metering and net billing as RE policies. We modeled the decision-making of market participants using the complementarity approach, with consideration of prosumer investments in DERs; battery operation; electric power networks; pricing schemes; and transmission cost recovery. The main factors examined were: prosumer investment decisions; transmission tariffs; and social surplus in equilibrium. We found that prosumer investment in PVs increases as the investment cost of PV decreases. As for net metering, the amount of prosumer electricity sales increases when prosumer investment in PVs increases and capital cost of PV decreases. The related prosumer decisions reduce the amount of producer electricity generation, and increase the transmission tariff for transmission cost recovery. On the other hand, in net billing (a scheme involving imposition of a tariff on prosumer electricity sales), prosumer investment in PVs is smaller than that in net metering. That lower prosumer investment in PVs leads to a decrease in prosumer electricity sales. Here, the transmission tariff does not change significantly because there is no significant impact on producer electricity generation. Thus, under both pricing schemes, an increase or decrease in prosumer electricity sales and transmission tariff affect the producer electricity generation and price for consumers and prosumers. These results vary with individual market participant surplus. The total social surplus is obtained as the overall result of all market participant surplus. In the ranges of high capital cost of PV, net metering and net billing yield roughly the same total social surplus. However, when the capital cost of PV is reduced, net billing yields a greater total social surplus because net metering is strongly affected by a decrease in consumer surplus. There is also a decrease in consumer surplus under net metering resulting from the impact of higher prices caused by a sharp increase in transmission tariffs with large prosumer investment in PVs. Besides, the total social surplus tends to increase with PV capital cost reduction, which suggests that the cost reduction in RE investment may constitute a future policy agenda. Subsequently, we analyzed the case where prosumers operate battery storage in addition to investing in PVs. Prosumer battery operation increases the prosumer investment in PVs. In this case, we suggested that net billing obtains a larger total social surplus consistent with the results of the case where prosumers do not consider battery operation. Moreover, the larger the difference in social surplus for each pricing scheme, the more the capital cost of PV decreased. Thus, whether prosumers operate battery storage or not, net billing results in a large social surplus, which indicates that our results are robust. Moreover, the total social surplus with battery operation became smaller than that without battery operation, due to the high capital cost of battery storage. That result indicates that further reduction of the capital cost of battery storage is required in order to achieve a larger social surplus with prosumer battery operation. This implies that further investment in R&D needs to be made to reduce the capital cost of battery storage. All of the above results suggest that a larger social surplus can be obtained by choosing the appropriate pricing scheme, with consideration of the capital cost of PV or battery storage. Specifically, if the capital cost of PV is reduced sufficiently, net billing may give rise to a larger social surplus.

We analyzed the impact of RE policies on investment decision-making in RE from various perspectives with consideration of the entire electricity market. It is expected that these policies will continue to influence the spread of RE strongly. In this study, we provided frameworks for the evaluation of RE policy with consideration of policy features and RE investment cost for further spread of RE in the future electricity market.

To achieve further decarbonization in the work to achieve the goals of the Paris Agreement, continuous investment in RE will be necessary. The results of this study indicate that even RE policies that are sufficiently effective at present will require additional research and updating, given changes in future electricity demand; investment cost of RE; and electricity market structure. Moreover, different RE policies are adopted in different regions and countries in accordance with RE investment cost reduction and resource bias. Therefore, future research toward appropriate policy selection should examine case studies with consideration of characteristics of each region, available resources, and the status of the spread of RE.

Appendix

A Dynamic optimization and proofs

A.1 Dynamic optimization under uncertainty

Assume that the state variable Y_t varies with uncertainly, and follows a stochastic differential equation.

$$dY_t = \mu(Y_t)dt + \sigma(Y_t)dW_t, \qquad Y_0 = y. \tag{A.1}$$

For any y of the state variable, let $\Psi(y)$ be the value of the project when the investment is made. Now, suppose the investment decision can be delayed by infinitesimal time dt. Then, the value of the project $G(y)$ is expressed as follows:

$$G(y) = max\left(\Psi\left(y\right), \mathbb{E}[e^{-\rho dt}G\left(y + dy\right)]\right) \tag{A.2}$$

Eq. (A.2) is the Bellman equation for the optimal stopping problem. Assuming that $G(y)$ is a twice-differentiable function, the value of delaying an investment decision by dt is expressed as Eq. (A.5) using Ito's lemma, Eq. (A.3) and Eq. (A.4). Note that higher-order terms are ignored.

$$dG(y) = \frac{dG(y)}{dy}dy + \frac{1}{2}\frac{d^2G(y)}{dy^2}(dy)^2 \tag{A.3}$$

$$e^{-\rho dt} = 1 - \rho dt \tag{A.4}$$

$$\begin{aligned}
&\mathbb{E}[e^{-\rho dt}G(y + dy)] \qquad (A.5)\\
&= \mathbb{E}[(1 - \rho dt)(dG(y) + G(y))]\\
&= \left(\mu(y)\frac{dG(y)}{dy} + \frac{1}{2}\sigma(y)^2\frac{d^2G(y)}{dy^2} - \rho G(y)\right) dt + G(y)
\end{aligned}$$

Using Eq. (A.5), Eq. (A.2) can be expressed as follows:

$$G(y) = max\left(\Psi(y), \left(\mu(y)\frac{dG(y)}{dy} + \frac{1}{2}\sigma(y)^2\frac{d^2G(y)}{dy^2} - \rho G(y)\right) dt + G(y)\right) \tag{A.6}$$

From the right-hand side of this Eq. (A.6), we can find the differential equation satisfied by $G(y)$ as follows:

$$\frac{1}{2}\sigma(y)^2\frac{d^2G(y)}{dy^2} + \mu(y)\frac{dG(y)}{dy} - \rho G(y) = 0 \tag{A.7}$$

When the state variable follows GBM, the general solution to Eq. (A.7) is obtained as follows:

$$G(y) = a_1 y^{\beta_1} + a_2 y^{\beta_2} \tag{A.8}$$

a_1, a_2 are the coefficients of the option value in Eq. (A.8). β_1 and β_2 are the positive and negative roots of the following characteristic equation Eq. (A.9), and can be derived as in Eq. (A.10).

$$\frac{1}{2}\sigma^2\beta(\beta-1)+\mu\beta-\rho=0 \tag{A.9}$$

$$(\beta_1,\beta_2)=\left(\frac{1}{2}-\frac{\mu}{\sigma^2}+\sqrt{\left(\frac{\mu}{\sigma^2}-\frac{1}{2}\right)^2+\frac{2\rho}{\sigma^2}},\frac{1}{2}-\frac{\mu}{\sigma^2}-\sqrt{\left(\frac{\mu}{\sigma^2}-\frac{1}{2}\right)^2+\frac{2\rho}{\sigma^2}}\right) \tag{A.10}$$

Here, $\beta_1 > 1, \beta_2 < 0$. Besides, since $G(0) = 0$ is satisfied, $a_2 = 0$, and the option value is obtained as follows:

$$G(y) = a_1 y^{\beta_1} \tag{A.11}$$

where the investment threshold y^* and the coefficient of option value a_1 are calculated from the following boundary conditions:

$$\begin{cases} G(y^*) = \Psi(y^*) \\ \frac{dG(y^*)}{dy} = \frac{d\Psi(y^*)}{dy} \end{cases} \tag{A.12}$$

The first line is the value-matching condition, which represents continuity. That is, the value of delaying the investment is equal to the value of stopping the investment at the level y^*. The second line is the smooth-pasting condition, which indicates that the solution is optimal.

A.2 Applying the real options approach to the TSO's problem

In this study, we apply the real options approach to represent the value of the TSO that maximizes social surplus through investment. The differential equation satisfied by $S_0(x)$ of the TSO is obtained as follows using Appendix A.1.

$$\frac{1}{2}\sigma(x)^2\frac{d^2S_0(x)}{dx^2}+\mu(x)\frac{dS_0(x)}{dx}-\rho S_0(x)+(1-\frac{1}{2}\eta Q_{0,L})Q_{0,L}x-B_{0,k}=0 \quad \text{(A.13)}$$

When the state variables follow GBM, the value of the TSO before investment, including the option value is calculated by solving the second-order (inhomogeneous) differential equation, Eq. (A.13), as follows:

$$S_0(x)=ax^{\beta_1}+\frac{(2-\eta Q_{0,L})Q_{0,L}x}{2(\rho-\mu)}-\frac{B_{0,k}}{\rho} \quad \text{(A.14)}$$

Here, β_1 follows the same characteristic equation as in Eq. (A.9).

A.3 Proof of Proposition 2 and Proposition 4

We show a proof of Proposition 2 and Proposition 4. First, the term $\frac{\beta_1}{\beta_1-1}$ is positive because $\beta_1>1$ from Appendix A.1.

$$\frac{\beta_1}{\beta_1-1}>0 \quad \text{(A.15)}$$

Next, the term $1-\frac{\eta}{2}(Q_{0,k}+Q_{1,k})$ can be rewritten as $1-\frac{\eta}{2}(Q_{0,k}+Q_{1,k})=\frac{1}{2}((1-\eta Q_{0,k})+(1-\eta Q_{1,k}))$. Since the power price is positive and $1-\eta Q_{i,k}>0$, we can derive the following equation:

$$1-\frac{\eta}{2}(Q_{0,k}+Q_{1,k})>0 \quad \text{(A.16)}$$

In addition, since $\rho > \mu$, and the other variables take positive values, the inequality in Proposition 2 and Proposition 4 holds. $\square$

B Prosumers with battery storage

Based on the model for prosumers used in Section 3.3.2, we suppose that prosumers operate battery storage. Prosumers maximize profits by determining the capacity of investment in PVs, electricity consumption, electricity sales/purchases, backup electricity generation, charge/discharge, and the amount of electricity stored under the pricing schemes and the given battery capacity.

B.1 Net metering

First, we model the prosumer optimization problem under the net metering scheme by considering the operation of the battery.

$$\underset{l_{it},g_{it},k_i,ch_{it},dc_{it}\geq 0,z_{it},bat_{it}}{\text{maximize}} \quad \sum_t (p_{it}+\tau) z_{it} B_t + \sum_t \left(\int_0^{l_{it}} p_{it}^{pro}(m_{it}) dm_{it} \right) B_t - \sum_t C_i^g(g_{it}) B_t - Ek_i - UW_i \quad \text{(B.1)}$$

subject to

$$\left(z_{it} + l_{it} - CF_t k_i + ch_{it} - dc_{it} - g_{it}\right) B_t \leq 0 \quad (\delta_{it})\text{(B.2)}$$

$$\left(g_{it} - G_i\right) B_t \leq 0 \quad (\kappa_{it})\text{(B.3)}$$

$$(bat_{it} - \sigma^{max} W_i) D \leq 0 \quad (\mu_{it}^{max})\text{(B.4)}$$

$$(-bat_{it} + \sigma^{min} W_i) D \leq 0 \quad (\mu_{it}^{min})\text{(B.5)}$$

$$\left(V^{ch} ch_{it} - \beta^{ch} W_i\right) B_t \leq 0 \quad (\gamma_{it}^{ch})\text{(B.6)}$$

$$\left(\frac{1}{V^{dc}} dc_{it} - \beta^{dc} W_i\right) B_t \leq 0 \quad (\gamma_{it}^{dc})\text{(B.7)}$$

$$bat_{it} = bat_{i3}(1 - M_{it}) + \left(V^{ch} ch_{it} - \frac{1}{V^{dc}} dc_{it}\right) B_t/D, (t=1) \quad (\eta_{it})\text{(B.8)}$$

$$bat_{it} = bat_{it-1}(1 - M_{it}) + \left(V^{ch} ch_{it} - \frac{1}{V^{dc}} dc_{it}\right) B_t/D, (t=2,3) \quad (\eta_{it})\text{(B.9)}$$

Prosumers determine the electricity consumption l_{it}, electricity sales/purchases z_{it}, backup electricity generation g_{it}, PV capacity k_i, electricity charge ch_{it}, electricity discharge dc_{it} at each node i and period t, and the amount of electricity stored bat_{it} at the end of period t at each node i to maximize their profits. The objective function consists of the revenue/payment associated with prosumer electricity sales/purchases, benefits from electricity consumption, cost of backup generation, PV capital cost, and capital cost of battery storage. Note that the capital cost of battery storage is given because the battery capacity W_i is exogenous. In addition, we add constraints related to battery operation (e.g., Long et al., 2018; Ding et al., 2020). Eqs. (B.4) and (B.5) are the upper and lower limits of the usable capacity as a ratio of the battery capacity, respectively, while Eqs. (B.6) and (B.7) are the rates of charge and discharge allowance per hour for the battery capacity, considering the charge and discharge efficiency, respectively. Eqs. (B.8) and (B.9) are constraints on the transition of stored electricity in the battery storage at the end of each period, in which the day is divided into three periods: peak, mid-peak, and off-peak. In Eq. (B.8), the amount of electricity stored in the battery storage at the end of the day matches the amount of electricity in the battery storage at the beginning of the day. The KKT conditions are derived as follows.

KKT conditions

$$(p_{it} + \tau - \delta_{it})B_t = 0, \forall i, \forall t \tag{B.10}$$

$$0 \leq l_{it} \perp \left(P_{it}^0 - \frac{P_{it}^0}{\alpha_i Q_{it}^0} l_{it} - \delta_{it} \right) B_t \leq 0, \forall i, \forall t \tag{B.11}$$

$$0 \leq g_{it} \perp \left(-C_i^{g'}(g_{it}) + \delta_{it} - \kappa_{it} \right) B_t \leq 0, \forall i, \forall t \tag{B.12}$$

$$0 \leq k_i \perp -E + \sum_t CF_t \delta_{it} B_t \leq 0, \forall i \tag{B.13}$$

$$0 \leq ch_{it} \perp \left(-\delta_{it} + \frac{V^{ch}}{D} \eta_{it} - V^{ch} \gamma_{it}^{ch} \right) B_t \leq 0, \forall i, \forall t \tag{B.14}$$

$$0 \leq dc_{it} \perp \left(\delta_{it} - \frac{1}{V^{dc} D} \eta_{it} - \frac{1}{V^{dc}} \gamma_{it}^{dc} \right) B_t \leq 0, \forall i, \forall t \tag{B.15}$$

$$(-\mu_{it}^{max} + \mu_{it}^{min})B_t - \eta_{it} + \eta_{it+1}(1 - M_{it+1}) = 0, \ \forall i, \forall t, \ (t = 1, 2) \tag{B.16}$$

$$(-\mu_{it}^{max} + \mu_{it}^{min})B_t - \eta_{it} + \eta_{i1}(1 - M_{i1}) = 0, \ \forall i, \forall t, \ (t = 3) \tag{B.17}$$

$$0 \leq \delta_{it} \perp (z_{it} + l_{it} - CF_t k_i + ch_{it} - dc_{it} - g_{it}) B_t \leq 0, \forall i, \forall t \tag{B.18}$$

$$0 \leq \kappa_{it} \perp (g_{it} - G_i)B_t \leq 0, \forall i, \forall t \tag{B.19}$$

$$0 \leq \mu_{it}^{max} \perp (bat_{it} - \sigma^{max} W_i)D \leq 0, \forall i, \forall t \tag{B.20}$$

$$0 \leq \mu_{it}^{min} \perp (-bat_{it} + \sigma^{min} W_i)D \leq 0, \forall i, \forall t \tag{B.21}$$

$$0 \leq \gamma_{it}^{ch} \perp (V^{ch} ch_{it} - \beta^{ch} W_i)B_t \leq 0, \forall i, \forall t \tag{B.22}$$

$$0 \leq \gamma_{it}^{dc} \perp \left(\frac{1}{V^{dc}} dc_{it} - \beta^{dc} W_i \right) B_t \leq 0, \forall i, \forall t \tag{B.23}$$

$$bat_{i1} = bat_{i3}(1 - M_{it}) + (V^{ch} ch_{it} - \frac{1}{V^{dc}} dc_{it}) B_t / D, (t = 1) \tag{B.24}$$

$$bat_{it} = bat_{it-1}(1 - M_{it}) + (V^{ch} ch_{it} - \frac{1}{V^{dc}} dc_{it}) B_t / D, (t = 2, 3) \tag{B.25}$$

Using these KKT conditions, the market equilibrium problem under net metering, considering the prosumer battery operation, is expressed by Eq. (3.30), Eqs. (3.32)–(3.38), (3.40), and Eqs. (B.10)–(B.25).

B.2 Net billing

Next, we consider the prosumer optimization problem under the net billing scheme with battery operation.

$$\underset{l_{it},g_{it},k_i,z^s_{it},z^b_{it},ch_{it},dc_{it},\geq 0,bat_{it}}{\text{maximize}} \sum_t \left((p_{it}+\tau^s)z^s_{it} - (p_{it}+\tau^b)z^b_{it}\right) B_t$$
$$+\sum_t \left(\int_0^{l_{it}} p^{pro}_{it}(m_{it})dm_{it}\right) B_t - \sum_t C^g_i(g_{it})B_t - Ek_i - UW_i \quad \text{(B.26)}$$

subject to

$$(z^s_{it} - z^b_{it} + l_{it} - CF_t k_i + ch_{it} - dc_{it} - g_{it})B_t \leq 0 \qquad (\delta_{it}) \quad \text{(B.27)}$$

$$(g_{it} - G_i)\, B_t \leq 0 \qquad (\kappa_{it}) \quad \text{(B.28)}$$

$$(bat_{it} - \sigma^{max}W_i)D \leq 0 \qquad (\mu^{max}_{it}) \quad \text{(B.29)}$$

$$(-bat_{it} + \sigma^{min}W_i)D \leq 0 \qquad (\mu^{min}_{it}) \quad \text{(B.30)}$$

$$(V^{ch}ch_{it} - \beta^{ch}W_i)B_t \leq 0 \qquad (\gamma^{ch}_{it}) \quad \text{(B.31)}$$

$$\left(\frac{1}{V^{dc}}dc_{it} - \beta^{dc}W_i\right) B_t \leq 0 \qquad (\gamma^{dc}_{it}) \quad \text{(B.32)}$$

$$bat_{it} = bat_{i3}(1-M_{it}) + (V^{ch}ch_{it} - \frac{1}{V^{dc}}dc_{it})B_t/D, (t=1) \qquad (\eta_{it}) \quad \text{(B.33)}$$

$$bat_{it} = bat_{it-1}(1-M_{it}) + (V^{ch}ch_{it} - \frac{1}{V^{dc}}dc_{it})B_t/D, (t=2,3) \qquad (\eta_{it}) \quad \text{(B.34)}$$

Prosumers maximize profit by determining the electricity consumption l_{it}, electricity sales z^s_{it}, electricity purchases z^b_{it}, backup electricity generation g_{it}, PV capacity k_i, electricity charge ch_{it}, electricity discharge dc_{it}, and electricity stored in the battery storage bat_{it}. The objective function comprises the revenue/payment associated with the prosumer electricity sales/purchases, benefits from electricity consumption, cost of backup generation, capital cost of PVs, and capital cost of battery storage. We can derive the following KKT conditions.

$$0 \le z^s_{it} \perp (p_{it} + \tau^s - \delta_{it})B_t \le 0, \forall i, \forall t \tag{B.35}$$

$$0 \le z^b_{it} \perp (-p_{it} - \tau^b + \delta_{it})B_t \le 0, \forall i, \forall t \tag{B.36}$$

$$0 \le l_{it} \perp \left(P^0_{it} - \frac{P^0_{it}}{\alpha_i Q^0_{it}} l_{it} - \delta_{it}\right) B_t \le 0, \forall i, \forall t \tag{B.37}$$

$$0 \le g_{it} \perp \left(-C^{g'}_i(g_{it}) + \delta_{it} - \kappa_{it}\right) B_t \le 0, \forall i, \forall t \tag{B.38}$$

$$0 \le k_i \perp -E + \sum_t CF_t \delta_{it} B_t \le 0, \forall i \tag{B.39}$$

$$0 \le ch_{it} \perp \left(-\delta_{it} + \frac{V^{ch}}{D}\eta_{it} - V^{ch}\gamma^{ch}_{it}\right) B_t \le 0, \forall i, \forall t \tag{B.40}$$

$$0 \le dc_{it} \perp \left(\delta_{it} - \frac{1}{V^{dc}D}\eta_{it} - \frac{1}{V^{dc}}\gamma^{dc}_{it}\right) B_t \le 0, \forall i, \forall t \tag{B.41}$$

$$(-\mu^{max}_{it} + \mu^{min}_{it})B_t - \eta_{it} + \eta_{it+1}(1 - M_{it+1}) = 0,\ \forall i, \forall t,\ (t = 1, 2) \tag{B.42}$$

$$(-\mu^{max}_{it} + \mu^{min}_{it})B_t - \eta_{it} + \eta_{i1}(1 - M_{i1}) = 0,\ \forall i, \forall t,\ (t = 3), \tag{B.43}$$

$$0 \le \delta_{it} \perp \left(z^s_{it} - z^b_{it} + l_{it} - CF_t k_i + ch_{it} - dc_{it} - g_{it}\right) B_t \le 0, \forall i, \forall t \tag{B.44}$$

$$0 \le \kappa_{it} \perp (g_{it} - G_i)B_t \le 0, \forall i, \forall t \tag{B.45}$$

$$0 \le \mu^{max}_{it} \perp (bat_{it} - \sigma^{max}W_i)D \le 0, \forall i, \forall t \tag{B.46}$$

$$0 \le \mu^{min}_{it} \perp (-bat_{it} + \sigma^{min}W_i)D \le 0, \forall i, \forall t \tag{B.47}$$

$$0 \le \gamma^{ch}_{it} \perp (V^{ch}ch_{it} - \beta^{ch}W_i)B_t \le 0, \forall i, \forall t \tag{B.48}$$

$$0 \le \gamma^{dc}_{it} \perp \left(\frac{1}{V^{dc}}dc_{it} - \beta^{dc}W_i\right) B_t \le 0, \forall i, \forall t \tag{B.49}$$

$$bat_{i1} = bat_{i3}(1 - M_{it}) + (V^{ch}ch_{it} - \frac{1}{V^{dc}}dc_{it})B_t/D, (t = 1) \tag{B.50}$$

$$bat_{it} = bat_{it-1}(1 - M_{it}) + (V^{ch}ch_{it} - \frac{1}{V^{dc}}dc_{it})B_t/D, (t = 2, 3) \tag{B.51}$$

The market equilibrium problem under the net billing scheme with battery operation is expressed using Eqs. (3.31)–(3.37), Eq. (3.39), Eq. (3.41), and Eqs. (B.35)–(B.51).

C Data

This section summarizes the data of generation units, intercepts, and slopes of inverse demand functions, load data, transmission capacity, periods, and capacity factor.

Table C.1: Characteristics of generation units
(Source : Chen et al. (2011,2020))

Node	Unit	Marginal cost($/MWh)	Capacity (MW)
a	1	38.00	250
a	2	35.72	200
a	3	36.80	450
b	4	15.52	150
b	5	16.20	200
b	6	20.00	200
c	7	17.60	400
c	8	16.64	400
c	9	19.40	450
c	10	18.60	200

Table C.2: Parameters of inverse demand functions

	Node	Peak	Mid peak	Off peak
P^0	a	220.8	220.8	214.2
	b	70.2	120	123
	c	105.6	99.6	99.6
Q^0	a	780	600	360
	b	480	336	216
	c	600	444	348

Table C.3: Load data

Node	Peak (MW)	Mid peak (MW)	Off peak (MW)
a	650	500	300
b	400	282	180
c	500	370	290

Table C.4: Transmission capacity
(Source : Chen et al. (2011,2020))

Lines	Limit (MW)
(a,b)	255
(b,c)	120
(c,a)	30

Table C.5: Period and capacity factor

	Peak	Mid peak	Off peak
B_t (hour)	1460	3285	4015
CF_t	0.70	0.45	0

Bibliography

M. L. Abadie, M. J. Chamorro , "Valuation of Wind Energy Projects: A Real Options Approach", *Energies*, vol. 7 (5), pp. 3218-3255, 2014.

J. R. Abbad , "Electricity market participation of wind farms: the success story of the Spanish pragmatism", *Energy Policy*, vol. 38 (7), pp. 3174–3179, 2010.

J. Aghaei, N. Amjady, A. Baharvandi, M. A. Akbari , "Generation and Transmission Expansion Planning: MILP–Based Probabilistic Model", *IEEE Transactions on Power Systems*, vol. 29 (4), pp. 1592-1601, 2014.

A. Arasteh , "Considering the investment decisions with real options games approach", *Renewable and Sustainable Energy Review*, vol. 72, pp. 1282-1294, 2017.

M. Avau, N. Govaerts, E. Delarue , "Impact of distribution tariffs on prosumer demand response", *Energy Policy*, vol. 151, pp. 112-116, 2021.

L. Barbosa, P. Ferrão, A. Rodrigues, A. Sardinha , "Feed-in tariffs with minimum price guarantees and regulatory uncertainty", *Energy Economics*, vol. 72, pp. 517–541, 2018.

L. Baringo, A. Conejo , "Transmission and wind power investment", *IEEE Transactions on Power Systems*, vol. 27 (2), pp. 885-893, 2012.

R. Barth, C. Weber, D. J. Swider , "Distribution of costs induced by the integration of RES-E power", *Energy Policy*, vol. 36 (8), pp. 3107-3115, 2008.

P. Bean, J. Blazquez, N. Nezamuddin , "Assessing the cost of renewable energy policy options - A Spanish wind case study", *Renewable Energy*, vol. 103, pp. 180-186, 2017.

G. Blanco, R. Pringles, F. Olsina, F. Garces , "Valuing a Flexible Regulatory Framework for Transmission Expansion Investment", *IEEE Bucharest Power Tech Conference*, 2019 June 28th - July 2nd, Bucharest, Romania.

J. Blazqueza, R. Fuentes-Bracamontes, C. A. Bollino, N. Nezamuddin , "The renewable energy policy Paradox", *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 1–5, 2018.

T. Bøckman, S. E. Fleten, E. Juliussen, H. J. Langhammer, I. Revdal , "Investment timing and optimal capacity choice for small hydropower projects", *European Journal of Operational Research*, vol. 190 (1), pp. 255–267, 2008.

T. K. Boomsma, N. Meade, S. E. Fleten , "Renewable energy investments under different support schemes: A real options approach", *European Journal of Operational Research*, vol. 220 (1), pp. 225–237, 2012.

T. K. Boomsma, K. Linnerud , "Market and policy risk under different renewable electricity support schemes", *Energy*, vol. 89, pp. 435-448, 2015.

B. Bosquet , "Environmental tax reform: does it work? A survey of the empirical evidence", *Ecological Economics*, vol. 34 (1), pp. 19–32, 2000.

S. Borenstein , "The economics of fixed cost recovery by utilities", *The Electricity Journal*, vol. 29, pp. 5–12, 2016.

A. Boretti, S. Castelletto, W. Al-Kouz, J. Nayfeh , "Capacity factors of solar photovoltaic energy facilities in California, annual mean and variability", E3S Web of Conferences 181, 02004, 5th International Conference on Sustainable and Renewable Energy Engineering (ICSREE), 2020.

A. Botterud, M. D. Ilic, I. Wangensteen , "Optimal investments in power generation under centralized and decentralized decision making", *IEEE Transactions on Power Systems*, vol. 20 (1), pp. 254-263, 2005.

C. F. Calvillo, A. Sánchez-Miralles, J. Villar, F. Martín , "'Optimal planning and operation of aggregated distributed energy resources with market participation" *Applied Energy*, vol 182, pp. 340-357, 2016.

F. M. Camilo, R. Castro, M. E. Almeida, V. F. Pires , "Economic assessment of residential PV systems with self-consumption and storage in Portugal", *Solar Energy*, vol. 150, pp. 353–362, 2017.

M. Castaneda, M. Jimenez, S. Zapata, C. J. Franco, I. Dyner , "Myths and facts of the utility death spiral", *Energy Policy*, vol. 110, pp. 105–116, 2017.

M. Castellini, F. Menoncin, M. Moretto, S. Vergalli , "Photovoltaic Smart Grids in the prosumers investment decisions: a real option model", *Journal of Economic Dynamics and Control*, vol. 126, 103988, 2021.

H. Chao "A market mechanism for electric power transmission", *Journal of Regulatory Economics*, vol. 10, pp. 25-59, 1996.

H. Chao , "Global electricity transformation: The critical need for integrated market design and risk management research", *Energy*, vol. 31 (6) pp. 923-939, 2006.

Y. Chen, A. L. Liu, B. F. Hobbs , "Economic and Emissions Implications of Load-Based, Source-Based, and First-Seller Emissions Trading Programs Under California AB32", *Operations Research*, vol. 59, no. 3, pp. 696-712, 2011.

Y. Chen, A. S. Siddiqui, M. Tanaka , "Analysis of Environmental Policy in the Power Sector: Equilibrium Methods and Bi-Level Modeling", *Springer International Publishing*, 2020.

C. Cheng, Z. Wang, M. Liu, Q. Chen, A. P. Gbatu, X. Ren , "Defer option valuation and optimal investment timing of solar photovoltaic projects under different electricity market systems and support schemes", *Energy*, vol. 127, pp. 594-610, 2017.

M. Chhabra, J. de Lamare , "NATURAL RESOURCES DEFENSE COUNCIL PROPOSAL FOR THE SUCCESSOR NET ENERGY METERING TARIFF", *Natural Resources Defense Council (NRDC)*, 2021.

M. Child, D. Bogdanov, A. Aghahosseini, C. Breyer , "The role of energy prosumers in the transition of the Finnish energy system towards 100% renewable energy by 2050", *Futures*, vol. 124, article no. 102644, 2020.

G. C. Christoforidis, I. P. Panapakidis, T. A. Papadopoulos, G. K. Papagiannis , I. Koumparou, M. Hadjipanayi, G. E. Georghiou, "A Model for the Assessment of Different Net-Metering Policies", *Energies*, vol. 9(4), 262, 2016.

M. Chronopoulos, V. Hagspiel, S. E. Fleten , "Stepwise investment and capacity sizing under uncertainty", *NHH Dept. of Business and Management Science Discussion Paper*, 2015.

W. Cole, A. W. Frazier , "Cost Projections for Utility-Scale Battery Storage" , *National Renewable Energy Lab. (NREL)*, NREL/TP-6A20-73222, 2019.

A. J. Conejo, R Sioshansi , "Rethinking Restructured Electricity Market Design: Lessons Learned and Future Needs", *International Journal of Electrical Power & Energy Systems*, vol. 98, pp. 520-530, 2018.

T. Couture, Y. Gagnon , "An analysis of feed-in tariff remuneration models: Implications for renewable energy investment" , *Energy Policy*, vol. 38 (2), pp. 955-965, 2010.

T. Dangl , "Investment and capacity choice under uncertain demand", *European Journal of Operational Research*, vol. 117 (3), pp. 415-428, 1999.

P. Denholm, R. M. Margolis , "Evaluating the limits of solar photovoltaics (PV) in traditional electric power systems", *Energy Policy*, vol. 35, pp.2852-2861, 2007.

R. Dufo-Lopez, J. L. Bernal-Augstín , "A comparative assessment of net metering and net billing policies. Study cases for Spain" , *Energy*, vol. 84, pp. 684-694, 2015.

Y. Ding, Q. Xu, Y. Huang , "Optimal sizing of user-side energy storage considering demand management and scheduling cycle", *Electric Power Systems Research*, vol. 184, article no. 106284, 2020.

A. K. Dixit, R. S. Pindyck , "Investment under uncertainty", Princeton, NJ, USA: *Princeton Unicersity Press*, 1994.

C. Eid, J. R. Guillén, P F Marín, R. Hakvoort , "The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives", *Energy Policy*, vol. 75, pp. 244–254, 2014.

P. Ekins , "How large a carbon tax is justified by the secondary benefits of CO_2 abatement?", *Resource and Energy Economics*, vol. 18 (2), pp. 161-187, 1996.

S. Fankhauser , "Climate change costs", *Energy Policy*, vol. 24 (7), pp. 665-673, 1996.

F. A. Felder, R. Athawale , "The Life and Death of the Utility Death Spiral", *The Electricity Journal*, vol. 27, Issue 6, pp. 9-16, 2014.

S. E. Fleten, K. M. Maribu, I. Wangensteen , "Optimal investment strategies in decentralized renewable power generation under uncertainty", *Energy*, vol. 32 (5), pp. 803–815, 2007.

S. E. Fleten, A. Heggedal, A. Siddiqui , "Transmission Capacity Between Norway and Germany - a Real Options Analysis", *Journal of Energy Markets*, vol. 4 (1), pp. 121-147, 2011.

S. E. Fleten, K. Linnerud, P. Molnár, M. T. Nygaard , "Green electricity investment timing in practice: Real options or net present value?", *Energy*, vol. 116 (1), pp. 498-506, 2016.

C. Fischer, G. R. Newell , "Environmental and technology policies for climate mitigation", *Journal of Environmental Economics and Management*, vol. 55 (2), pp. 142–162, 2008.

T. J. Foxon, R. Gross, A. Chase, J. Howes, A. Arnall, D. Anderson , "UK innovation systems for new and renewable energy technologies: drivers, barriers and systems failures", *Energy Policy*, vol. 33 (16), pp. 2123-2137, 2005.

A. Gautier, J. Jacqmin, J. C. Poudou , "The prosumers and the grid", *Journal of Regulatory Economics*, vol. 53, no. 1, pp. 100-126, 2018.

J. S. González, R. Lacal-Arántegui , "A review of regulatory framework for wind energy in European Union countries: Current state and expected developments", *Renewable and Sustainable Energy Reviews*, vol. 56, pp. 588-602, 2016.

W. Gorman, S. Jarvis, D. Gallaway , "Should I Stay Or Should I Go? The importance of electricity rate design for household defection from the power grid", *Applied Energy*, vol. 262, article no. 114494, 2020.

L. H. Goulder , "Environmental Taxation and the Double Dividend: A Reader's Guide", *International Tax and Public Finance*, vol. 2 (2), vol. 157-183, 1995.

M. Goyal, S. Netessine , "Strategic technology choice and capacity investment under demand uncertainty", *Management science*, vol. 53 (2), pp. 192-207, 2007.

V. Hagspiel, K. J. M. Huisman, P. M. Kort , "Volume flexibility and capacity investment under demand uncertainty", *International Journal of Production Economics*, vol. 178, pp. 95-108, 2016.

B. F. Hobbs , "Linear Complementarity Models of Nash–Cournot Competition in Bilateral and POOLCO Power Markets", *IEEE Transactions on Power Systems*, vol. 16, no. 2, 2001.

IEA , "World Energy Outlook 2019", *International Energy Agency (IEA)*, Paris https://www.iea.org/reports/world-energy-outlook-2019, 2019a.

IEA , "Japan 2021",*International Energy Agency (IEA)*, Paris https://www.iea.org/reports/japan-2021, 2021.

IEA , "Global Energy & CO2 Status Report 2019", *International Energy Agency (IEA)*, Paris https://www.iea.org/reports/global-energy-co2-status-report-2019, 2019b.

C. Inês, P. L. Guilherme, M. G. Esther, G. Swantje, H. Stephen, H. Lars , "Regulatory challenges and opportunities for collective renewable energy prosumers in the EU", *Energy Policy*, vol. 138, article no. 111212, 2020.

IRENA , "Renewable Power Generation Costs in 2020", *International Renewable Energy Agency (IRENA)*, 2021.

IRENA , "Adapting market design to high shares of variable renewable energy", *International Renewable Energy Agency (IRENA)*, 2017.

IRENA , "Net billing schemes: Innovation landscape brief", *International Renewable Energy Agency (IRENA)*, 2019.

T. Jamasb, M. Pollitt , "Electricity Market Reform in the European Union: Review of Progress toward Liberalization & Integration", *Energy Journal*, vol. 26 (SPEC. ISS.), pp. 11-41, 2005.

C. Long, J. Wu, Y. Zhou, N. Jenkins , "Peer-to-peer energy sharing through a two-stage aggregated battery control in a community Microgrid", *Applied Energy*, vol. 226, pp. 261–276, 2018.

P. L. Joskow , “Lessons Learned From Electricity Market Liberalization” *Energy Journal*, vol. 29, Special Issue 2, pp. 9-42, 2008.

L. Joskow , “Transmission policy in the United States”, *Utilities Policy*, vol. 13 (2), pp. 95-115, 2005.

K. Kappner, P. Letmathe, P. Weidinger , “Optimisation of photovoltaic and battery systems from the prosumer-oriented total cost of ownership perspective”, *Energy, Sustainability and Society*, vol. 9 (1), pp. 1-24, 2019.

L. Kitzing, C. Mitchell, P. E. Morthorst , “Renewable energy policies in Europe: Converging or diverging?” *Energy Policy* vol. 51, pp. 192-201, 2012.

L. Kitzing, N. Juul, M. Drud, T. K. Boomsma , “A real options approach to analyse wind energy investments under different support schemes”, *Applied Energy*, vol. 188, pp. 83–96, 2017.

P. M. Kort, P. Murto, G. Pawlina , “Uncertainty and stepwise investment”, *European Journal of Operational Research*, vol. 202 (1), pp. 196-203, 2010.

M. Kozlova, S. E. Fleten, V. Hagspiel , “Investment timing and capacity choice under rate-of-return regulation for renewable energy support”, *Energy*, vol. 174, pp. 591-601, 2019.

W. Krewitt, T. Heck, A. Truknemüller, R. Friedrich , “Environmental damage costs from fossil electricity generation in Germany and Europe”, *Energy Policy*, vol. 27 (3), pp. 173-183, 1999.

R. Künneke, T. Fens , “Ownership unbundling in electricity distribution: The case of The Netherlands”, *Energy Policy*, vol. 35 (3), pp. 1920-1930, 2007

F. Kunz , “Improving congestion management: How to facilitate the integration of renewable generation in Germany”, *Energy Journal*, vol. 34 (4), pp. 55-78, 2013.

E. Kuznetsova, M. F. Anjos , "Prosumers and energy pricing policies: When, where, and under which conditions will prosumers emerge? A case study for Ontario (Canada)" , *Energy Policy*, vol. 149, article no. 111982, 2021.

M. N. Lavrutich , "Capacity choice under uncertainty in a duopoly with endogenous exit", *European Journal of Operational Research*, vol. 258 (3), pp. 1033–1053, 2017.

J. Lee, Y. Cho, Y. Koo, C. Park , "Effects of Market Reform on Facility Investment in Electric Power Industry: Panel Data Analysis of 27 Countries", *Sustainability*, vol. 10 (9), 3235, 2019.

Z. Lia, M. Shahidehpour, A. Alabdulwahab, Y. Al-Turki , "Valuation of distributed energy resources in active distribution networks", *The Electricity Journal*, vol. 32, pp. 27–36, 2019.

A. Lüth, J. M. Zepter, P. C. Granado, R. Egging , "Local Electricity Market Designs for Peer-to-Peer Trading: The Role of Battery Flexibility", *Applied Energy*, vol. 229, pp. 1233-1243, 2018.

A. MacGillvray, H. Jeffrey, M. Winskel, I. Bryden , "Innovation and cost reduction for marine renewable energy: A learning investment sensitivity analysis", *Technological Forecasting & Social Change*, vol. 87, pp. 108-124, 2014.

D. S. Mallapragada, D. J. Papageorgiou, A. Venkatesh, C. L. Lara, I. E. Grossmann , "Impact of model resolution on scenario outcomes for electricity sector system expansion", *Energy*, vol. 163, pp. 1231-1224, 2018.

L. Maurovich-Horvat, T. K. Boomsma, A. Siddiqui , "Transmission and Wind Investment in a Deregulated Electricity Industry", *IEEE Transactions on Power Systemps*, vol. 30 (3), pp. 1633 - 1643, 2015.

Ministry of the Environment , “Details on the Carbon Tax (Tax for Climate Change Mitigation)”, https://www.env.go.jp/en/policy/tax/env-tax.html, 2012.

D. M Newbery , “European Deregulation Problems of liberalising the electricity industry”, *European Economic Review*, vol. 46 (4,5), pp. 919-927, 2002.

M. Nicolini, M. Tavoni , “Are renewable energy subsidies effective? Evidence from Europe”, *Renewable and Sustainable Energy Reviews*, vol. 74, pp. 412-423, 2017.

OCCTO , “Standard unit cost of electric poewr transmission and substation equipment”, https://www.occto.or.jp/access/oshirase/2015/files/20160329_tanka_kouhyou.pdf, 2016.(Japanese)

OECD/IEA , “Projected Costs of Generating Electricity”, 2015.

OECD , “Share of emissions priced and average price signals from tax & ETS, by total”, http://oe.cd/emissionsdata, 2016.

A. D. Owen , “Renewable energy: Externality costs as market barriers”, *Energy Policy*, vol. 34 (5), pp. 632–642, 2006.

G. Palmer , “Household Solar Photovoltaics: Supplier of Marginal Abatement, or Primary Source of Low-Emission Power?”, *Sustainability*, vol. 5, pp. 1406-1442, 2013.

Y. Parag, and B. K. Sovacool , “Electricity market design for the prosumer era”, *Nature Energy*, vol. 1, no. 4, article no. 16032, 2016.

D. Peng, R. Poudineh , “Electricity market design under increasing renewable energy penetration: Misalignments observed in the European Union”, *Utilities Policy*, vol. 61, 100970, 2019.

J. Pfeifenberger , “Transmission Cost Allocation and Cost Recovery in the West”, *Transmission Executive Forum WEST 2011*, 2011.

M. Pollitt , “The arguments for and against ownership unbundling of energy transmission networks”, *Energy Policy*, vol. 36 (2), pp. 704–713, 2008.

A. Poullikkas, G. Kourtis, I. Hadjipaschalis , “A review of net metering mechanism for electricity renewable energy sources”, *International Journal of Energy and Environmental Engineering*, vol. 4 (6), pp. 975-1002, 2013.

R. Pringles, F. Olsina, F. Garcés , “Designing regulatory frameworks for merchant transmission investments by real options analysis”, *Energy Policy*, vol. 67, pp. 272–280, 2014.

J. L. Prol, K. W. Steininger , “Photovoltaic self-consumption regulation in Spain: Profitability analysis and alternative regulation schemes”, *Energy Policy*, vol. 108, pp. 742-754, 2017.

A. Pyrgou, A. Kylili, P. A. Fokaides , “The future of the Feed-in Tariff (FiT) scheme in Europe: The case of photovoltaics”, *Energy Policy*, vol. 95, pp. 94–102, 2016.

P. Ralon, M. Taylor, A. Ilas, H. Diaz-Bone, K-P. Kairies , “Electricity storage and renewables: Costs and markets to 2030”, *International Renewable Energy Agency (IRENA)*, 2017.

S. Ramyar, A. L. Liu, Y. Chen , “A Power Market Model in Presence of Strategic Prosumers”, *IEEE Transactions on Power Systems*, vol. 35, no.2, pp. 898-908, 2020.

W. H. Reuter, J. Szolgayová, S. Fuss, M. Obersteiner , “Renewable energy investment: Policy and market impacts”, *Applied Energy*, vol. 97, pp. 249-254, 2012.

I. Ritzenhofen, S. Spinler , “Optimal design of feed-in-tariffs to stimulate renewable energy investments under regulatory uncertainty — A real options analysis”, *Energy Economics*, vol. 53, pp. 76-89, 2016.

P. Río del, M. A. Gual , "An integrated assessment of the feed-in tariff system in Spain", *Energy Policy*, vol. 35 (2), pp. 994–1012, 2007.

H. Schermeyer, C. Vergara, W. Fichtner , "Renewable energy curtailment: A case study on today's and tomorrow's congestion management", *Energy Policy*, vol. 112, pp. 427-436, 2018.

J. Schallenberg-Rodriguez, R. Haas , "Fixed feed-in tariff versus premium: A review of the current Spanish system", *Renewable and Sustainable Energy Reviews*, vol. 16 (1), pp. 293-305, 2012.

J. Schallenberg-Rodriguez , "Renewable electricity support system: Design of a variable premium system based on the Spanish experience", *Renewable Energy*, vol. 68, pp. 801-813, 2014.

J. Schallenberg-Rodriguez , "Renewable electricity support systems: Are feed-in systems taking the lead?", *Renewable and Sustainable Energy Reviews*, vol. 76, pp. 1422-1439, 2017.

L. Sereno, T. Efthimiadis , "Capacity constraints, transmission investments, and incentive schemes", *Energy Policy*, vol. 119, pp. 8-27, 2018.

A. Siddiqui, R Sioshansi, A. J. Conejo , "Merchant storage investment in a restructured electricity industry", *The Energy Journal*, vol. 40 (4), 2019.

R. Sioshansi , "When energy storage reduces social welfare", *Energy Economics*, vol. 41, pp. 106-116, 2014.

J. Stern, J. R. Davis , "Economic reform of the electricity industries of Central and Eastern Europe", *Economics of Transition*, vol. 6(2), pp. 427-460, 1998.

M. Taylor, P. Ralon, H. Anuta, S. Al-Zoghoul , "Renewable Power Generation Costs in 2019", *International Renewable Energy Agency (IRENA)*, 2020.

J. Tirole , “The Theory of Industrial Organization”, *MIT Press Books*, 1988.

R. S. J. Tol , “The Damage Costs of Climate Change Toward More Comprehensive Calculations”, *Environmental and Resource Economics*, vol. 5, pp. 353-374, 1995.

R. S. J. Tol , “The marginal damage costs of carbon dioxide emissions:an assessment of the uncertainties”, *Energy Policy*, vol. 33 (16), pp. 2064–2074, 2005.

A. Verbruggen, V. Lauber , “Basic concepts for designing renewable electricity support aiming at a full-scale transition by 2050”, *Energy Policy*, vol. 37, pp.5732–5743, 2009.

M. M. Villena, J. Jacqmin, R. Fonteneau, A. Gautier , “Network tariffs and the integration of prosumers: The case of Wallonia”, *Energy Policy*, vol. 150, article no. 112065, 2021.

J. Wagner , “Grid Investment and Support Schemes for Renewable Electricity Generation”, *Energy Journal*, vol. 40 (2), pp. 195-220, 2017.

D. Watts, M. F. Valdés, D. Jara, A. Watson , “Potential residential PV development in Chile: The effect of Net Metering and Net Billing schemes for grid-connected PV systems”, *Renewable and Sustainable Energy Reviews*, vol. 41, pp. 1037-1051, 2015.

L. Weißensteiner, R. Haas, H. Auer , “Offshore wind power grid connection - The impact of shallow versus super-shallow charging on the cost-effectiveness of public support”, *Energy Policy*, vol. 39 (8), pp. 4631-4643, 2011.

J. Winkler, A. Gaio, B. Pfluger, M. Ragwitz , “Impact of renewables on electricity markets – Do support schemes matter?”, *Energy Policy*, vol. 93, pp. 157–167, 2016.

J. M. Wittmayer, F. Avelino, B. Pel, I. Campos , "Contributing to sustainable and just energy systems? The mainstreaming of renewable energy prosumerism within and across institutional logics", *Energy Policy*, vol. 149, 112053, 2021.

C.K. Woo, D. Lloyd, R. Karimov, A. Tishler , "Stranded cost recovery in electricity market reforms in theUS", *Energy*, vol. 28, pp. 1–14, 2003.

Y. Zeng, W. Chen , "The Determination of Concession Period for Build-Operate-Transfer Solar Photovoltaic Power Project under Policy Incentives: A Case Study of China", *Energies*, vol. 12 (18), pp. 1-23, 2019.