European Journal of Operational Research 000 (2016) 1–17

Contents lists available at ScienceDirect

European Journal of Operational Research

journal homepage: www.elsevier.com/locate/ejor

Decision Support

Transmission and generation investment in electricity markets: The effects of market splitting and network fee regimes

Veronika Grimm[a,c], Alexander Martin[b], Martin Schmidt[b,c,*], Martin Weibelzahl[b], Gregor Zöttl[d]

[a] Friedrich-Alexander-Universität Erlangen-Nürnberg, Chair of Economic Theory, Lange Gasse 20, Nürnberg 90403, Germany
[b] Friedrich-Alexander-Universität Erlangen-Nürnberg, Discrete Optimization, Cauerstr. 11, Erlangen 91058, Germany
[c] Energie Campus Nürnberg, Fürther Str. 250, Nürnberg 90429, Germany
[d] Friedrich-Alexander-Universität Erlangen-Nürnberg, Industrial Economics and Energy Markets, Lange Gasse 20, 90403 Nürnberg, Germany

ARTICLE INFO

Article history:
Received 5 March 2015
Accepted 27 March 2016
Available online xxx

Keywords:
Electricity market modeling
Mixed-integer nonlinear optimization
Multilevel programming
Network expansion
Transmission management

ABSTRACT

We propose an equilibrium model that allows to analyze the long-run impact of the electricity market design on transmission line expansion by the regulator and investment in generation capacity by private firms in liberalized electricity markets. The model incorporates investment decisions of the transmission system operator and private firms in expectation of an energy-only market and cost-based redispatch. In different specifications we consider the cases of one vs. multiple price zones (market splitting) and analyze different approaches to recover network cost—in particular lump sum, generation capacity based, and energy based fees. In order to compare the outcomes of our multilevel market model with a first best benchmark, we also solve the corresponding integrated planner problem. Using two test networks we illustrate that energy-only markets can lead to suboptimal locational decisions for generation capacity and thus imply excessive network expansion. Market splitting heals these problems only partially. These results are valid for all considered types of network tariffs, although investment slightly differs across those regimes.

1. Introduction

Following the British privatization in the 1980s, various countries around the world liberalized their electricity sectors. Today, in most industrialized countries only the transmission network remains regulated while private firms decide on investment in generation capacities and trade electricity on markets. This structure challenges the planning of transmission and generation capacity expansion. While an entirely regulated electricity sector allows for simultaneous transmission and generation expansion planning, in a liberalized market, investment decisions in transmission and generation capacities are taken by different agents. Investment in generation capacities is typically made by firms and private investors based on their expectations concerning the future regulatory environment. Network expansion, however, is decided on by regulated firms (or even the regulator), in anticipation of capacity investments by private firms. Traditional optimization approaches, which only consider integrated transmission and generation expansion planning, reveal the optimal expansion plan for transmission and generation but do not offer valuable information on how to achieve those goals in a mixed market/non-market environment. In a liberalized market, incentives induced by the interplay of the market environment and regulation determine whether firms make the appropriate investment choices. As our results clearly reveal, the proper design of market rules providing adequate incentives in those markets crucially matters. Liberalized electricity markets thus call for new tools to inform the various agents involved: regulators, electricity firms, investors, and other stakeholders.

In this paper we propose a model that allows to analyze investment decisions by the regulator and private firms in liberalized electricity markets. We model energy-only markets and a regulated transmission system operator (TSO) who uses cost-based redispatch to deal with transmission constraints. In a multilevel analysis we study transmission expansion decisions by the

* Corresponding author at: Friedrich-Alexander-Universität Erlangen-Nürnberg, Discrete Optimization, Cauerstr. 11, 91058 Erlangen, Germany. Tel.: +49 91318567160.
E-mail addresses: veronika.grimm@fau.de (V. Grimm), alexander.martin@math.uni-erlangen.de (A. Martin), mar.schmidt@fau.de (M. Schmidt), martin.weibelzahl@math.uni-erlangen.de (M. Weibelzahl), gregor.zoettl@fau.de (G. Zöttl).

http://dx.doi.org/10.1016/j.ejor.2016.03.044

regulated TSO in anticipation of capacity expansion by private firms. In different instantiations of our model we analyze the effects of market splitting (one vs. multiple price zones) as well as different approaches to recover network cost—in particular a lump sum, a generation capacity based, and an energy based fee. In order to compare the outcomes to a first best benchmark we also solve the integrated planner problem. For the computational studies we restrict ourselves to solving stylized test cases to illustrate the applicability of our framework. The results demonstrate that investment choices in a market environment substantially differ from the first best solution. In our numerical examples the absence of proper locational investment incentives for firms clearly affects investment choices of generators, which, in turn, leads to excessive line investment. This shows that our model allows to compare different network management regimes and to quantify their effects on long-run investment decisions. Our approach is thus an important extension of various studies that have mainly considered the short-run properties of different transmission management regimes; see the literature review below. As we show, transmission management has also important implications in the long-run when generation and transmission expansion are taken into account.

Let us emphasize that our approach allows to assess the long-run impact of different transmission management regimes adopted in liberalized electricity markets around the world. Especially in Europe spot market trading does not fully account for transmission constraints. In contrast, capacities are shut down and called by the TSO in case that the spot market solution is technically infeasible. Under cost-based redispatch (as it is used in Austria, Switzerland, or Germany) firms called into operation are just compensated for their variable production cost. Consequently, redispatch operations cannot contribute to the recovery of investment cost.[1] Other liberalized electricity markets adopted a system of nodal prices (see, e.g., Joskow, 2008), where spot market prices directly reflect transmission constraints (e.g., the United States, Canada, Australia, or New Zealand), which induces more adequate incentives for generation capacities by private firms. To at least partially overcome the lack of locational signals provided by spot market prices, several countries that rely on a system of redispatch have introduced price zones (e.g., Sweden and Italy). Since the first best solution coincides with the outcome obtained under nodal pricing in our framework, our approach also allows to assess the long-run benefits of a change to this transmission management system.

Apart from the consideration of nodal prices and price zones as compared to a uniform price spot market, we also analyze the impact of different network fee regimes. We consider a lump sum fee as a theoretical benchmark that does not directly affect investment decisions for generation capacity. In practice, however, network fee regimes typically combine energy based and capacity based components. For instance, the current practice in the UK uses "Transmission Network Use of System" fees that are collected based on power plant capacity connected to the grid, whereas "Balancing Services Use of System Charges" fees are charged based on energy fed into the network (cf. National Grid, 2015). In order to provide some insights on the desirability of different network fee regimes, we consider the extreme cases of an energy based and a purely capacity based network fee. The insights of Ruderer and Zöttl (2012) that a lump sum fee yields the highest generation investment incentives and a capacity based fee the lowest (with the energy based fee in between) are reflected in our computational results. In the discussion of our case studies we provide an intuition and moreover demonstrate that the clear ranking of the network fee regimes in terms of investment incentives does not translate into a clear ranking in terms of welfare. The desirability of a network fee regime rather depends on whether distortions induced by the market design itself are alleviated or worsened by higher investment.

1.1. Literature review

Prior to the liberalization of electricity sectors around the world, vertically integrated monopolists (either regulated or directly state owned) were responsible for generation and transmission expansion. Such monopolists needed insights on the cost minimal configuration of the system. As a consequence, traditionally most of the contributions proposed frameworks and techniques to determine overall optimal expansion for generation and transmission facilities; see, e.g., Gallego, Monticelli, and Romero (1998), Binato, Pereira, and Granville (2001), Alguacil, Motto, and Conejo (2003), or de Oliveira, da Silva, Pereira, and Carneiro (2005). In a recent contribution Ruiz and Conejo (2015) propose robust optimization techniques to analyze transmission expansion planning under uncertainty.

In liberalized electricity markets, however, we observe vertical unbundling of transmission and generation facilities. Thus, in addition to insights on the global optimum of an integrated monopolist, research is needed on how the market environment affects decisions of different stakeholders. By now a large literature has developed, which analyzes incentives for private and potentially strategic firms to invest in generation facilities. However, these studies typically assume unlimited transmission capacity; examples are Gabszewicz and Poddar (1997), Murphy and Smeers (2005), Joskow and Tirole (2007), Zöttl (2010), Fabra, von der Fehr, and de Frutos (2011), de Frutos and Fabra (2011), Grimm and Zöttl (2013), or Wogrin, Hobbs, Ralph, Centeno, and Barquín (2013).

Another recent strand of literature explicitly models both generation and transmission investment typically by making use of bilevel models. Sauma and Oren (2006, 2009) are among the first to model investment incentives of generators and transmission network expansion in such a way. In their contribution they quantify the impact of whether transmission investment anticipates resulting investment of strategic generation companies or not. Roh, Shahidehpour, and Fu (2007) propose a simulation framework to analyze investment of competitive generation companies and competitive merchant transmission companies. Roh, Shahidehpour, and Wu (2009) generalize this framework to also include a transmission system operator as a further agent. van der Weijde and Hobbs (2012) provide a bilevel model of transmission expansion facing uncertain investment in renewable generation. Baringo and Conejo (2012) propose a bilevel model together with MPEC- and MILP-based reformulation techniques that addresses investment in wind power plants and transmission lines in a market environment. Ryan, Downward, Philpott, and Zakeri (2010) and, in an extension, Jin and Ryan (2011) analyze expansion of electricity generation and transmission capacities together with the expansion of a fuel transportation network. For electricity markets, Jenabi, Ghomi, and Smeers (2013) propose a clear-cut bilevel framework which considers optimal network expansion by the transmission company, anticipating investment of competitive generation companies. Also based on a bilevel approach, O'Neill, Krall, Hedman, and Oren (2013) propose an auction mechanism to implement optimal investment incentives by transmission companies. In a recent contribution Huppmann and Egerer (2015) also use a bilevel approach to analyze the strategic interaction among several transmission companies and their incentives to build transmission

[1] In contrast, market-based redispatch (used, e.g., in Belgium, Finland, France, or Sweden) may yield rents for firms that are called at the redispatch and thus induces incentives to build plants at locations with systematic underprovision, see Grimm, Martin, Sölch, Weibelzahl, and Zöttl (2016). However, market-based redispatch is plagued by severe gaming problems, which obtain even for perfectly competitive markets. In the literature this is often referred to as the inc-dec game. For a discussion of these issues see, e.g., Neuhoff, Hobbs, and Newbery (2011).