Energy Policy 117 (2018) 184–197

Contents lists available at ScienceDirect

Energy Policy

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

Pricing the transition: Empirical evidence on the evolution of electricity rate structures in North America

Simon Langlois-Bertrand[a,*], Pierre-Olivier Pineau[b]

[a] Norman Paterson School of International Affairs, Carleton University, 1125 Colonel By Dr., Ottawa, Ontario, Canada K1S 5B6
[b] Chair in Energy Sector Management, HEC Montréal, 3000 chemin de la Côte-Sainte-Catherine, Montréal, Québec, Canada H3T 2A7

ARTICLE INFO

Keywords:
Electricity
Tariffs
Transition
North America
United States
Canada

ABSTRACT

Over recent years, utilities supplying the residential electricity sector have struggled with a growing discrepancy between revenues and costs. The increasing share of fixed costs became difficult to recover through traditional rate structures, based on volumetric pricing. This trend is exacerbated by the increase in distributed and intermittent generation from renewable sources, and by changes in demand profiles. This study asks whether utilities across North America are adapting to these changes and taking advantage of dynamic pricing tools and demand response technologies, by taking stock of common tariffing practices to see if utilities do implement rates better tailored to support these transformations. We look at the U.S. Energy Information Administration's national survey, and then refine our analysis with 31 cases across North America. By looking at utilities' current rate practices with regard to dynamic pricing, distributed generation, the integration of new technologies, demand response possibilities, as well as electric vehicle recharge, this exploration makes it clear that a large majority are not ready for these challenges and must innovate rapidly. Moreover, regulatory agencies must ensure that utilities do have the option of designing rates that move away from volume-based pricing and allow for the deployment of sophisticated demand response management.

1. Introduction

The electricity sector is central to the efforts aimed at curtailing climate change. The availability of alternative, low-carbon generation technologies and the relatively large scale of potential reductions to greenhouse gas emissions have made it one the most important – and successful – targets of public policies. For several years, public authorities around the world have been encouraging and compounding efforts to encourage a transition from the "traditional" model based on fossil fuels combustion.

While this renewable electricity transition is well underway in several OECD countries, its transformational impact is accompanied by – and in some cases, creates – substantial challenges to electricity systems. Changes are rapid and put in question many of the characteristics of the central grid paradigm of electricity generation and distribution, which has dominated the 20th century. This model is characterized by large-scale generation in power plants, high-voltage transmission lines, and networks to distribute electricity to where it is to be consumed. As a result from this model, conventional relationships are maintained between supply and distribution companies,[1] on the one hand, and end-users of various types, on the other.

This traditional model is pressured from several angles. First, technologies that generate electricity from renewable sources, often encouraged by public policy, can be developed at a small scale. This makes distributed generation (DG) more attractive to various actors, requiring adaptation from distribution companies. Second, the increasing shares of renewable sources in the overall electricity mix, most notably solar and wind, require of utilities that they find ways to manage intermittency. This difficulty is compounded by the growing number of DG sites. Third, electricity demand is evolving in different and new ways: energy efficiency efforts, a trend well under way since the 1980s, has curtailed growth and customers' self-production and storage further dents utilities' demand (EIA, 2015; Sioshansi, 2016). Moreover, the penetration of electric vehicles (EVs) will play an increasing role in changing the load profile of different classes of customers (IEA, 2016a).

These challenges have been – and continue to be – discussed at length in various arenas, and analysts and major national and international institutions have devoted substantial attention to them (for instance, IEA, 2014, 2016b). There are various responses that utilities

* Corresponding author.
E-mail address: simonlangloisbertran@cmail.carleton.ca (S. Langlois-Bertrand).

[1] Although we use the general term "utility" for the greater part of the discussion throughout the article, in some instances we use the term "distribution company" to refer more specifically to electric utilities involved in both distribution and retailing activities.

https://doi.org/10.1016/j.enpol.2018.03.009
Received 28 August 2017; Received in revised form 26 February 2018; Accepted 4 March 2018
Available online 20 March 2018
0301-4215/

have sought to put in practice and that public authorities have tried to encourage. More sophisticated management of transmission and distribution networks, made possible by smart grids and demand response technologies, have in particular opened up possibilities for utilities to shape these changes in ways that remain profitable. These efforts, however, remain uneven around the world, with some jurisdictions showing promising progress in this regard while other utilities and networks are still in the early stages of this transformation.

While a lot of attention has been given to determining what is needed for electricity network actors and regulators to address some of these challenges (Boyd, 2014; Costello, 2014; Golden and Paulos, 2015; Karier, 2015; Morgan and Crandall, 2017; Pollitt, 2016; RMI, 2015; Sioshansi, 2016; Weisman, 2017; Wood et al., 2016), more limited attention has been devoted to the recent evolution of retailing practices of electric utilities. In addition to their revenue needs, utilities' role in using dynamic pricing options and other means to exploit this demand response potential is essential, especially given the growing share of fixed costs (CERES, 2015; Fares and King, 2017; IEA, 2016b). This is crucial to the transformation of the energy system described above, as tariffs that do not reflect costs lead to inefficiencies in the system, may encourage consumer behavior that is detrimental to hopes of meeting these challenges, and do not foster the integration of new technologies available today to move electric grids forward and ensure a successful transition.

Our main objective is to provide an analysis of North American practices in this regard, based on very recent empirical evidence. In this article, we ask whether North American utilities have changed their tariffs and rate structures to address these challenges and, if not, whether some regulatory discussions have taken place in their state or province to reform the current business model. Is it common practice for these utilities to implement rates better tailored to support the transformations described above? To answer this question, we begin by looking at the U.S. Energy Information Administration's national mandatory survey (EIA 861), which is sent to all U.S. utilities to get information on their revenues and sales, but also on several aspects of their retailing practices (EIA, 2016). Although this analysis is limited to the United States, it allows us to point out general trends.

Then, we present evidence from a more in-depth analysis of rate practices for a sample of 31 North American utilities (10 from Canada, 20 from the United States, and Mexico's national utility), along with a review of the local regulatory rate structure discussions. The case selection is explained in Section 3.2. Throughout the analysis, we focus on residential tariffs, and compare across all cases and against the trends and needs mentioned above to determine what general observations can be made. We focus on the residential sector for several reasons: it is arguably the sector where the challenges described above are at their peak, given the scale of fixed costs associated to this sector, the extent to which the simplest volumetric rate approach is used, the number of individual customers, their individually small contribution to the utility's revenues, and their important role in the advent of DG from renewable sources. For these reasons, this customer class is particularly interesting to our research objectives.

The next section provides some additional background information on rate design in North America. Section 3 then proceeds to explain our methodology and the data we gathered, followed by a discussion of the results of the investigation in Section 4. Section 5 then presents conclusions and potential solutions to the challenges and lacks identified, and their policy implications.

2. Background

Historically, electricity rates for residential customers have generally been dominated by a volumetric charge for every kilowatt-hour (kWh) of energy consumed. A relatively small fixed daily or monthly charge (often called customer charge) is usually added. In contrast to commercial or industrial rates, residential customers very rarely face a

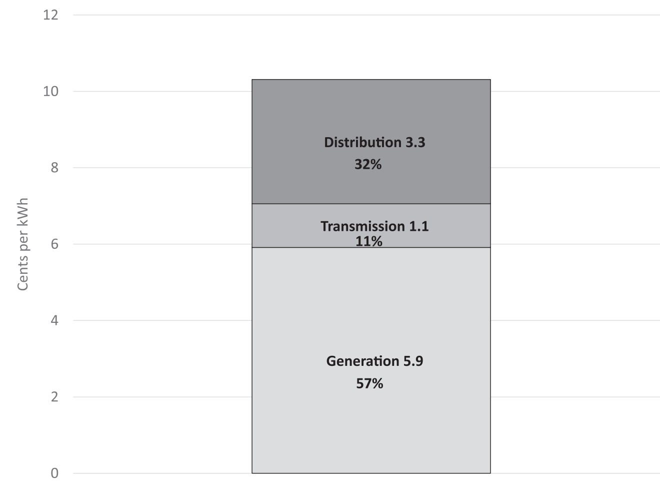

Fig. 1. Components of the U.S. average price of electricity, 2016 (EIA, 2017a).

power demand charge (in dollars by kilowatt, $/kW), which prices the peak power demand of customers. A rate structure using such a power demand charge has a double advantage: it limits peak demand, and hence the need to scale up infrastructure, and it covers a higher share of fixed costs. As illustrated by Fig. 1, 43% of the 2016 U.S. average price of electricity comes from distribution and transmission, which have limited variable components in their cost structure. Even generation (57% of the average price) has an important share of fixed costs.

One of the main objectives of tariffs for utilities is cost recovery from each customer class. In practice however, other and more general principles are often taken into account by public utilities commissions (PUCs) in rate regulation, such as fairness, horizontal and vertical equity among customers, or broader societal goals such as grid reliability, the provision of relief to low-income customers, or the fostering of technological innovation.

The combination of these objectives for any given market makes rate design a complex exercise, both art and science (Bonbright, 1961). In part, the complexity of establishing electricity rate structures stems from the different nature of its components (Fig. 1). On top of more diffuse goals like innovation or renewable generation, rate structures must find a way to properly price a private good (i.e., the energy generated and used by consumers), as well as club goods,[2] such as generation capacity, transmission, distribution and customer service. A large part of the challenge lies in the fact that generation costs for electricity are often variable, while costs for the associated club goods are fixed (capacity costs). Even more, these structures have to evolve to follow new circumstances and technological progress, such as the increasing share of fixed-cost only renewable generation (wind and solar have indeed near zero-variable costs). Competition in the retail sector, when it happens, does not change the issue. Transmission and distribution remain regulated, while generation and the energy component of the power supply may be contestable. In both cases, fixed costs are mostly paid for through volumetric charges, and this approach is now challenged.

A large body of literature exists on rate design. The main reference for principles to apply in rate design remains Bonbright et al. (1988). Desirable attributes of rate designs are reproduced in Table 1, and provide the required context to the analysis done in Section 4 below.

Given the transformations already described in the introduction, some utilities and retailers have begun offering a variety of rate options to residential customers. These options take into account both the customers' specific profiles and distribution constraints, for instance

[2] Club goods are defined as non-rivalrous, but excludable, goods (Cornes and Sandler, 1996), such as a movie in a theater. Consumption is non-rivalrous as long as maximal capacity is not reached.