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Distributed renewable resources and the utility business model

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ABSTRACT

The recent calls for a new utility business model, to avoid a DER-induced death spiral, fail to fully understand the important role the utility business model has played in funding regulatory-driven social programs. Over the past 30 years, as new regulatory demands have been placed on the utility, the utility business model has evolved. The new DER challenge to the utility business model is basically a new form of uneconomic bypass that requires regulators to get utility pricing right, to reflect both the incremental and full cost of utility service.

1. Introduction

Broadly speaking, distributed energy resources (DER) (any form of distributed generation (DG), net metering energy sources, demand-response programs, price-responsive electric vehicles, energy efficiency, and distributed-level storage services) is providing the impetus for developing a new utility business model. Specifically, recent talk of the need for a new utility business model across the country is predicated on the continued technological innovations in metering, communications, and distributed storage, coupled with the rapid growth of customer-owned renewable energy self-generation at the distribution level. Such advances allow for non-utility energy interactions at the distribution level, and may ultimately provide for customer independence from the grid. To the extent that customers leave the grid and the utility's costs do not decrease accordingly, rates to remaining ratepayers will increase. Higher rates will provide incentives for more of the remaining ratepayers to leave the grid. Hence, without a new business model that is not based on the growth in electricity sales, the regulated utility will find itself in a "death spiral."

While this narrative seems rational on the surface, it is based upon three assumptions that are examined in this article. The first assumption is that the 100-year-old vertically integrated utility business model is inadequate to deal with the technology of the 21st century. The second assumption is that independence from the grid is in the customers' best interest, for both reliability/resiliency and economic reasons. Independence would allow for the continued availability of electricity during extreme weather events, such as the polar vortex and Hurricane Sandy. Independence also implies that the utility service model, traditionally a natural monopoly, is no longer a "least-cost" option to the customer any longer. A customer who is able to meet her/his energy needs by self-generating may infer that the utility transmission and distribution services are redundant and discontinue contributing to utility fixed costs. The third assumption, an implicit one, is that the utility business model no longer meets regulators' needs. Regulatory goals have moved beyond the safe-and-reliable provision of energy. For the last 30 years, the utility has proven to be both the laboratory and the provider/collector of funds needed to meet the societal energy goals of increased energy efficiency and reductions in greenhouse gas (GHG) emissions. To the extent that the current utility business model can no longer fund these societal goals, regulators will also have to find a new business model.

2. The evolution of the utility business model

The assumptions that the vertically integrated business model has remained static and is based on the continued growth in energy sales lead to a strawman model that is easily discredited. However, the utility business has been evolving with changes in technology, business climate, and regulatory mandates for social programs. One of the oldest and most established social programs is energy efficiency: programs specifically designed to mitigate the growth in electricity sales.

2.1. Energy efficiency and integrated resource planning

The current calls for a new utility business model are not new. Previous warnings of the need for a new business model initially surfaced in the 1970s and early 1980s to avoid an impending utility death spiral. A slowdown in electric sales coupled with

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unanticipated, high rates of inflation, two oil embargoes, and significant nuclear power plant cost overruns created economic challenges to the vertically integrated electric utility business model. As rate increases failed to keep pace with surging costs, utility solvency became questionable. Regulatory responses such as changes in the timing of rate cases, corrections for financial attrition, and Allowance for Funds Used During Construction (AFUDC), provided some relief to the utility business model based on cost recovery through electricity sales.[1] In addition to regulatory relief, another response to high electric rates was elicited.

Higher-than-expected costs eventually led to higher electric rates. To mitigate the impact of higher electric rates, it became reasonable to use electricity more efficiently. This behavioral response is predicted by the basic economic theory that higher prices are used to signal the increased scarcity of the resource and provide an incentive to use less of the resource. Changes in electric rate design supported this view as declining block per-kWh rate structures were changed to increasing block rate structures. However, this change in rate design was used to highlight that the efficient use of electricity was somehow different for electricity than for other resources. This uniqueness was embodied in a new term, "negawatt"; the most cost-effective kWh is the one not used.

This interpretation led to a new way to plan the electric grid and set the course for the current round of calls for a new business model. Use of the term negawatt redefines the concept of energy efficiency from an attribute describing how electricity is used, to a resource in its own right, one that shifts the derived demand for electricity inwards and can be added to the grid as an independent resource. Energy efficiency was now viewed as a resource that should be used in planning the electric grid.[2] Electric grid planning evolved into integrated resource planning (IRP), where energy efficiency/demand response programs are considered to be an equal building block, along with generation resources and transmission facilities, in designing the electric grid. The idea was to build a safe electric grid that would explicitly incorporate a societal goal: slower growth in electricity usage. However, to reach this goal, the utility needed to be compensated for its energy efficiency efforts and meeting its revenue requirements led to decoupling of revenues from electric sales.

2.2. Decoupling

Decoupling refers to the disassociation of a utility's profits from its sales of the energy commodity. Instead, a rate of return is aligned with meeting a given revenue target. Rates are trued up or down between rate cases to meet the revenue target. This makes the utility indifferent to selling less electricity in the short run. That is, decoupling improves the ability of energy efficiency programs, demand response programs, and distributed generation to operate within the utility environment and protects investors from lost margins between rate cases.

However, the operative phrase is short-run indifference. While decoupling may be a method to compensate investors for lost margins between rate cases associated with the promotion of DER, it does not necessarily create a long-term, sustainable, investment opportunity for the shareholder. Decoupling does not provide utilities with the incentives to promote energy efficiency, demand response, or the integration of DER at cost-based rates. Importantly, in the long run, decoupling does not provide a solution to the anticipated, systematic, erosion of rate base resulting from DER-induced declines in consumption and peak demand. While the utility may be indifferent to lost sales in a decoupled environment, theoretically no worse off for promoting DER, it does not solve the potential death spiral related to long run DER.

2.3. PURPA and electric restructuring

In the late 1970s, the Public Utility Regulatory Policies Act of 1978 (PURPA) demonstrated that generation need not be built and owned by the utility.[3] Generation could, in fact, be provided by third parties through the use of cogeneration. Efficient combined heat and power was not new, but to become a viable source of generation that could compete with the vertically integrated utility's generation assets, PURPA provided both a guaranteed customer (the utility) for excess energy, which was priced at the utility's avoided cost, and nondiscriminatory access to the transmission grid. The generation segment could be removed from the vertically integrated utility business model. This would eventually lead to a "new" utility business model where merchant generation would compete in a competitive, wholesale energy market with guaranteed nondiscriminatory access to the transmission grid. The regulated utility would build and maintain the network of wires, the decreasing cost transmission and distribution systems. This new business model was formally implemented and extended through electric industry restructuring.

In the late 1990s through early 2000s, electric restructuring dominated the electric utility business model in California, New York, PJM, and New England. Restructuring focused on providing incentives for the vertically integrated utility to sell its nonnuclear generating assets, keeping the utilities financially viable by ensuring stranded cost recovery, and providing open access to the transmission grid through the creation of a FERC regulated independent system operator (ISO) or regional transmission organization (RTO). Electric restructuring unbundled generation from utility transmission and distribution and created a competitive, wholesale energy market. With the creation of a competitive, wholesale generation market, the utility would remain the main energy demand aggregator for its service territory ratepayers. The aggregation of the utilities' hourly demand would intersect with the ISO supply curve to determine the market clearing energy price.

Restructuring in California failed for many reasons culminating in the well-known energy crisis of 2000 and 2001, but one of the main reasons was that all the restructuring effort was placed on ensuring competition on the supply side. Hourly energy market

[1] Financial attrition can result from using historical test years in a rising unit cost environment. Attrition can be mitigated by using forward test years in rate cases, interim rate increases, cost trackers to quickly include new capital projects into ratebase when they become used and useful, higher customer charges, and rate cases for multiple years with escalation rates built in for interim years. When utilities are not allowed to recover in current rates a return necessary to finance construction projects during the construction period, they will generally be allowed to capitalize the financing costs for future recovery from ratepayers. AFUDC represents capitalized interest and equity costs, which will ultimately be included in rate base as a component of plant in service, thereby earning a return and being recovered through depreciation allowances. (Lowry et al., 2010, pp. 55–57)

[2] Energy efficiency programs are administered by utilities, state agencies, and other third parties and are paid for by utility ratepayers, typically through a non-bypassable system benefits charge.

[3] The Public Utility Regulatory Policies Act of 1978 (PURPA) was implemented to encourage, among other things, the conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, equitable retail rates for electric consumers, expeditious development of hydroelectric potential at existing small dams, and conservation of natural gas while ensuring that rates to natural gas consumers are equitable. One of the ways PURPA set out to accomplish its goals was through the establishment of a new class of generating facilities which would receive special rate and regulatory treatment. Generating facilities in this group are known as qualifying facilities (QFs), and fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities (FERC).