Retail Electricity Tariff and Mechanism Design to Incentivize Distributed Renewable Generation

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Abstract

This paper examines the question of how to incentivize the adoption and use of renewable energy resources, with particular attention on distributed renewable energy (DRE). Prior experience suggests that price and quantity-based programs, such as feed-in tariffs, provide more efficient renewable adoption and use and lower program costs than programs that set quantity targets only. We also examine some cost-allocation issues raised by the use of DRE systems and fixed time-invariant retail pricing. This combination can result

costs being increasingly borne by customers who do not have access to DRE, creating undesirable cross-subsidies. As such, some jurisdictions have, ex post, limited or rescinded incentive programs to mitigate these issues.

This paper studies these problems in incentive and retail tari design to eciently encourage DRE adoption and use. It also provides lessons learned from previous attempts and failures. It further makes some recommendations on how to mitigate the unintended cost-allocation consequences of DRE-related incentive schemes through better tari design. The remainder of this paper is organized as follows. Section 2 summarizes the types of incentive programs used to date. It provides a comparative assessment of how well dierent programs work in incentivizing DRE adoption and reducing financing risks and costs. This section also discusses some of the philosophical reasons that certain mechanisms are sometimes favored over others. Section 3 introduces the negative cost-allocation consequences of these programs. Section 4 discusses two proposals for retail tari design—real-time pricing and two-par accommodate the relative maturity of different technologies. van der Linden et al. (2005) and Lipp (2007) note that the price guarantees in an FiT program can also decline over time. This allows the program to adapt to changing technology maturity levels over time and can also provide strong incentives for technology cost reductions.

van der Linden et al. (2005) note that the main criticism of the FiT system is that its efficiency depends on the price guarantee being set correctly. If the price is too high the system could result in excessive qualifying facilities for 20 years but also included explicit provisions to reduce rates paid to new deployments over time to reflect technologies maturing. Liou (

technology costs. Mitchell et al. (2006) and Lipp (2007) raise something of a philosophical advantage to quota-obligation systems, in that technology choice and prices are not set by legislative or regulatory fiat. Instead, by setting an obligation and allowing entities to use any combination of qualifying technologies to meet it, the market is able to determine what combination of technologies to use. Mitchell et al. (2006) further note that because the quota-obligation system does not set specific prices for different technologies, the government is not in a position of picking 'winners' and 'losers.'

However, these features of the quota-obligation system can be weaknesses. If a goal of DRE incentive programs is to drive down costs in the long-run, a quota-obligation system may only do this for technologies that are already mature (

the associated energy. These long-term contracts provide the type of revenue guarantee that an FiT does, allowing for lower-cost financing of a renewable project. As an opposite example, van der Linden et al. (2005)

a price guarantee, this has the potential to provide greater risk a

renewable developer may not operate or maintain the facility e□ciently. Similarly, the incentive to locate a project where renewable resources are ideal is muted and a developer may instead opt for a location that minimizes investment cost. For these reasons, production- or performance-based subsidies are strongly preferred. The four mechanisms discussed before all have this feature (in the case of a tendering or quota-obligation system, it has this feature if the obligation is energy- as opposed to capacity-based).

Tax-based incentives (either production- or investment cost-based) are often preferred to more direct financial subsidies or grants. This is because the cost of a tax-based incentive is typically more opaque, reducing potential political opposition to a program.

2.6. Renewable Integration

Integrating renewable and DRE resources into an electric power system can entail ancillary costs, in addition to the capital cost of the plant itself. One of these is the cost of transmission and distribution infrastructure to interconnect a plant with the system. Transmission infrastructure would apply more to utility-scale renewables whereas distribution infrastructure to DRE. Texas and China present two interesting case studies of possible means of addressing these additional investment costs. In the case of Texas, the state has proactively made transmission investments in anticipation of where it expects future renewable resources to be deployed (Langniss and Wiser, 2003). These costs are then socialized to customers on a pro rata basis. In the case of China, Liu and Kokko (2010) note that State Grid (one of the two transmission system operators in the country) invested in a wind power project. The investment provided State Grid with a strong incentive to make transmission investments. By doing so, it was able to maximize the value of its wind-plant investment. It should be noted, however, that State Grid's investment in the wind plant contradicts China's policy decision to separate power generation from transmission operation.

These two cases suggest policy steps that could be taken to incentivize transmission and distribution investments. Proactively making transmission and distribution investments in anticipation of renewable and DRE installations could reduce risks (and associated financing costs) of plants not being able to deliver their product to the market. Although cost socialization is typically suboptimal, it is an easy means of allocating these costs. Vertically integrating transmission and generation runs counter to most electricity market restructuring e□orts. For this reason, we do not necessarily recommend the Chinese approach for transmission investment. However, this type of an arrangement could be implemented for distribution infrastructure investments needed for DRE integration. One approach would be to have distribution utilities directly contract with DRE owners to purchase their energy and, if operating with a quota-obligation system, RECs. Doing so would provide the utility with strong incentives to ensure that there is su□cient distribution capacity available to e□ciently use available DRE resources.

3. Cost-Allocation with Distributed Renewable Energy

DREs and many of the programs used to incentivize their adoption and use raise some unique retail pricing challenges that have not been encountered in the past. This is because electricity sey aamtif

Overall, volumetric charges result in inefficient cost allocation with DRE. It should be stressed that this issue is not limited to PV, as it can apply just as well to other DRE resources (e.g., distributed wind). Moreover, this cost allocation problem is not limited to high penetrations of DRE. However, high penetrations of DRE exacerbates the issue, because the capacity value of most DRE resources tends to decrease as the penetration rises. In many parts of the world, the combination of DRE and volumetric energy-based tariffs can also create undesirable cross subsidies. This cross subsidy is due to DRE tending to be installed by customers that are socioeconomically better off than average. As these customers install more DRE, they pay a disproportionately smaller portion of capacity costs. These capacity costs are instead borne by customers without DRE, who tend to be socioeconomically worse off than those who own DRE.

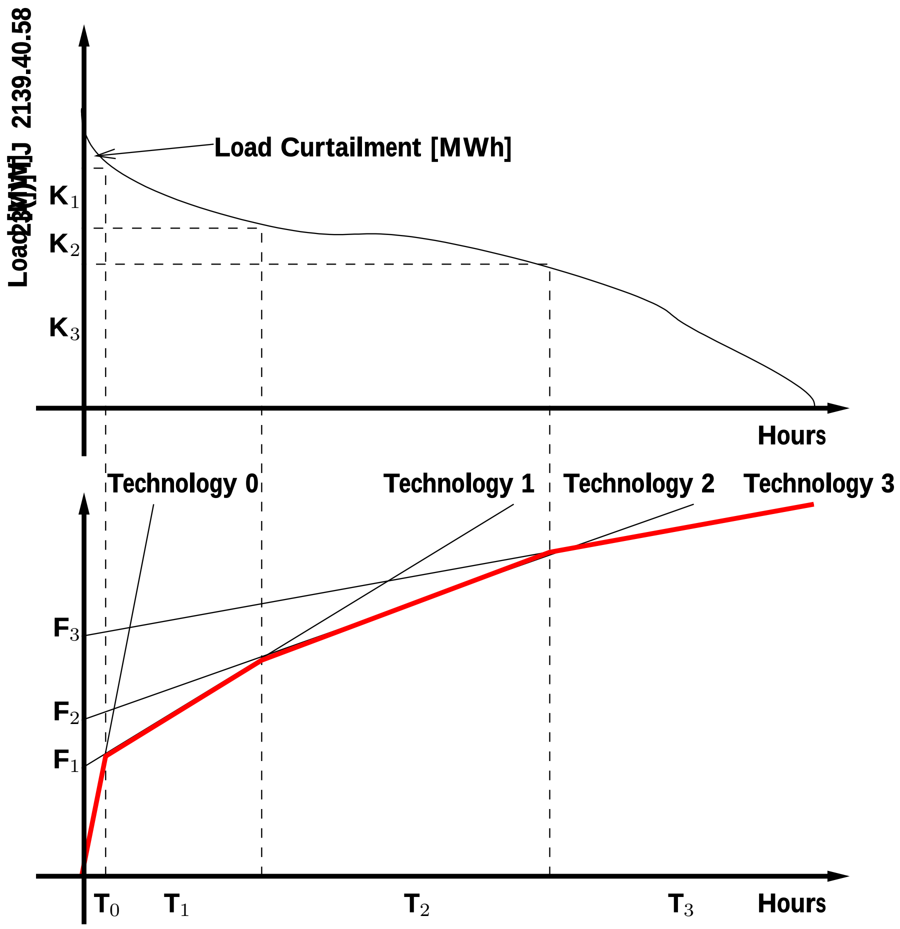
4. Proposed Tariff Design

In this section we propose two retail pricing structures—real-time pricing (RTP) and a two-part tariff with demand charges—to address the cost-allocation issue raised in Section 3. We use the stylized screening model introduced by Stoft (2002) to justify our proposed pricing schemes. We proceed by first introducing the simplified capacity investment model. We then present the two cost-recovery theorems, which explain what wholesale pricing structures could be used to recover fixed capacity-investment and variable operating costs. Finally, we use the results of the two cost-recovery theorems to justify our proposed retail pricing schemes and discuss the relative tradeoffs between the two. Some practical implementation details are also discussed.

4.1. Capacity Investment Model

Our capacity investment model assumes that a power system entails capacity investment and generator operation. Capacity planning includes investments in generation, transmission, and distribution. We assume that the system has N different generation technologies available and let F_n denote the per-MW fixed cost of installing and maintaining generation technology n. Our model is agnostic to whether F_n represents the total fixed cost of the generation asset over its lifetime or an amortized cost (e.g., the sum of an annualized capital cost and annual fixed maintenance cost). For ease of exposition we assume that F_n is an annualized fixed cost. F_n includes the cost of generation capacity in addition to the incremental transmission and distribution capacity required to deliver energy to end customers during the coincident peak-load period of the planning horizon. We also let C_n denote the per-MWh cost of operating5(c)6899384.4-1.66393(r)-631213(e)-1.66393

Property 1. **Once the generation mix is determined, the installed genera**


2139.40.58
Load Curtailment [MWh]
K$_1$
K$_2$
K$_3$
Hours
Technology 0
Technology 1
Technology 2
Technology 3
F$_3$
F$_2$
F$_1$
T$_0$
T$_1$
T$_2$
T$_3$
Hours

hours of the year that Technology 1 is marginal it is paid C_1 per MWh. Repeating this argument we find that its total revenue is given by:

$$\sum_{i=0}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n. \tag{1}$$

Adding each of the revenue terms (corresponding to the hours of the year during which the different technologies are marginal) in Equation (1) traces the lower envelope of the cost curves and gives the same dot in Figure 2 corresponding to the per-MW cost of the capacity increment.

Thus, we have that:

$$F_n + C_n \cdot \left(\sum_{i=0}^{n-1} T_i + \hat{T}_n \right) = \sum_{i=0}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n,$$

meaning that this capacity increment exactly recovers all of its fixed and variable costs through the proposed remuneration scheme. □

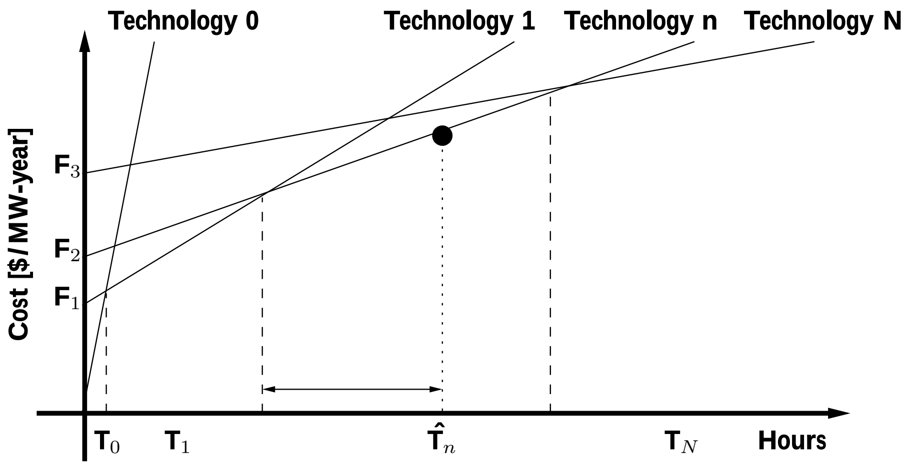


Figure 2: Illustration of proof of Theorem 1.

Theorem 2. If the assumptions of Theorem 1 hold then the following remuneration scheme ensures full fixed- and variable-cost recovery:

1. whenever load is curtailed, the system marginal cost is set equal to the variable cost of the peaking technology (i.e., C_1);
2. each MWh produced is paid the system marginal cost; and
3. every generator is given a capacity payment equal to the capacity cost of the peaking technology (i.e., F_1).

Proof.

However, Property 3 requires that:

$$\mathbf{C}_0 \cdot \mathbf{T}_0 = \mathbf{F}_1 + \mathbf{C}_1 \cdot \mathbf{T}_0.$$

Thus, under the remuneration scheme proposed here the capacity increment shown in Figure 2 earns:

$$\mathbf{F}_1 + \mathbf{C}_1 \cdot \mathbf{T}_0 + \sum_{i=1}^{n-1} \mathbf{C}_i \cdot \mathbf{T}_i + \mathbf{C}_n \cdot \hat{\mathbf{T}}_n = \mathbf{C}_0 \cdot \mathbf{T}_0 + \sum_{i=1}^{n-1} \mathbf{C}_i \cdot \mathbf{T}_i + \mathbf{C}_n \cdot \hat{\mathbf{T}}_n = \sum_{i=0}^{n-1} \mathbf{C}_i \cdot \mathbf{T}_i + \mathbf{C}_n \cdot \hat{\mathbf{T}}_n,$$

to integrating DRE as they do to utility-scale renewable plants. Thus, RTP has an added benefit (beyond cost recovery) of easing technical challenges raised by integrating large amounts of DRE.

The primary disadvantage of RTP is that it can introduce price and cost uncertainty to end customers.

benefits. As noted above, an added benefit of RTP is that it can help mitigate the negative impacts of real-time DRE availability uncertainty and variability. Demand charges would have no benefit in this area.

5. Conclusion and Policy Implications

In this paper we examine the question of how to incentivize the adoption and use of renewable energy resources, with particular attention on DRE. Our survey of systems that have been used suggest that FiTs tend to work better than quantity-based systems. The tendering system has been the least successful of those implemented in the past. If well designed, a quota-obligation system can effectively encourage renewable adoption. However, even in the case of Texas, where an RPS has been largely successful, it is not clear if an FiT would not have delivered the same levels of renewable investment at lower cost (given the cost results observed in the United Kingdom). Comparing the experience in the United Kingdom, Germany, and Denmark suggests that FiTs can deliver renewables at lower total cost than quantity-only based mechanisms. This is a question requiring further research.

In the particular case of DRE a net-metering system, either on its own or in conjunction with an FiT or quantity-based incentive program, can effectively spur renewable investment. Its success largely depends on the quality of the renewable resource and the level of retail prices. The southwestern United

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