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Optimal Policies to Promote Efficient Distributed Generation of Electricity

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by

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Abstract

We analyze the design of policies to promote efficient distributed generation (DG) of electricity. The optimal policy varies with the set of instruments available to the regulator and with the prevailing DG production technology. DG capacity charges often play a valuable role in inducing optimal investment in DG capacity, allowing payments for DG production to induce the optimal production of electricity using non-intermittent DG technologies. Net metering can be optimal in certain settings, but often is not optimal, especially for non-intermittent DG technologies.

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1 Introduction

The distributed generation of electricity is already pervasive in many countries and is expanding rapidly throughout the world.[1] Distributed generation (DG) is popular in part because it can limit the amount of capacity required at the primary production site, reduce electricity distribution costs (by moving generation sites closer to final consumers), and reduce generation externalities (e.g., carbon emissions).[2]

In addition to its many potential benefits, DG introduces at least two policy challenges that presently are the subject of heated debate.[3] First, depending upon the established retail prices for electricity and the terms of compensation for DG investment and production, electricity customers may undertake excessive or insufficient DG investment and production (Wiser et al., 2007; Borenstein, 2015). Second, as customers generate some or all of the electricity they consume, the centralized supplier of electricity ("the utility") experiences declines in revenue that typically exceed the associated avoided costs, given the large fixed infrastructure costs of the typical utility (Linvill et al. 2013; Lively and Cifuentes, 2014; Perez-Arriaga and Bharatkumar, 2014).

At least three changes have been proposed to help ensure the solvency of electric utilities while encouraging efficient DG investment and production. First, revised utility rate structures have been proposed. Rate structures that entail higher fixed charges for the right to purchase electricity from the utility and lower marginal charges for electricity actually purchased from the utility can better align the utility's revenues and costs in the presence of widespread DG (Brown and Faruqui, 2014; Costello, 2015).[4]

Second, various payments for DG production have been advocated, including alternatives

[1]See (DNV GL, 2014), the World Alliance for Decentralized Energy (2014), and Solar Energy Industries Association (2015), for example. The distributed generation of electricity entails the "generation of electricity from sources that are near the point of consumption, as opposed to centralized generation sources such as large utility-owned power plants" (American Council for an Energy-Efficient Economy, 2015).

[2]See Weissman and Johnson (2012), for example.

[3]NCCETC (2015d) reviews recent and ongoing DG policy initiatives throughout the U.S.

[4]Such rate restructuring can be viewed as a form of decoupling the utility's revenue from the amount of electricity it supplies. In addition to promoting efficient investment in DG capacity, decoupling can encourage a utility to promote energy conservation (Brennan, 2010a).

to common net metering policies. Under these policies, DG production causes a customer's electricity meter to run backward, so the consumer is effectively paid the prevailing retail price of electricity for each unit of electricity he produces on-site. Alternatives to such net metering include: (i) "value of production" feed-in tariffs, whereby a DG customer is compensated for the electricity he produces on-site at a rate that reflects the estimated net social value of the electricity (Farrell 2014a,b); and (ii) "avoided-cost" tariffs, whereby the unit payment for DG production reflects the associated reduction in the utility's production cost.

Third, additional charges on DG suppliers have been suggested. Several states have proposed that DG customers pay a fixed fee (independent of the level of the customer's installed DG capacity) to the utility. Proposed monthly fees vary from \$4.65 in Utah to \$25 in Maine.[5] DG charges that increase with a customer's generating capacity also have been implemented. For example, the Virginia Electric and Power Company imposes a monthly charge of \$4.19/kW on DG units with capacities between 10 and 20 kW (VSCC, 2011).[6] Additional charges on DG customers that increase with their maximum monthly consumption of electricity also have garnered attention (e.g., Hledik, 2014; Faruqui and Hledik, 2015).

Despite the widespread policy debate and the substantial variety of policies that have been proposed or implemented, formal analysis of the optimal design of DG compensation is limited.[7] This research is intended to help fill this void in the literature and to provide some

[5] See Maine Public Utilities Commission (2013) and NCCETC (2015d).

[6] The largest utility in Arizona presently imposes a fee of \$0.70/kW on solar DG capacity, and has suggested that this fee be raised to \$3.00/kW (NCCETC, 2015d). In 2014, the Wisconsin Public Service Commission approved a capacity charge of \$3.79/kW on wind and solar DG. See NCCETC (2015d) and filings in the Arizona Corporation Commission's Docket No. 13-0248 (http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18039#docket-detail-container2) and in the Wisconsin Public Service Commission Docket No. 5-UR-107 (http://psc.wi.gov).

[7] Industry experts have provided useful recommendations regarding various elements of DG compensation. Couture and Gagnon (2010), Kind (2013), and Raskin (2013), among others, review and discuss these recommendations. However, these recommendations typically do not reflect the explicit predictions of comprehensive, formal economic models. Darghouth et al. (2011, 2014) and Poullikkas (2013) simulate the effects of selected forms of DG compensation. Yamamoto (2012) models some considerations in the design of DG compensation policies, but abstracts from such elements as the full impact of DG investment on a consumer's energy costs. Brown and Sappington (2015a) examine whether common net metering policies are ever optimal in a setting where the regulator's retail pricing instruments are limited, DG capacity

guidance to policymakers on this important matter. We characterize the retail tariffs, payments for DG production, and charges for DG capacity investment that maximize consumer welfare while ensuring the solvency of the regulated utility. Our analysis allows for both intermittent and non-intermittent DG technologies. Solar panels constitute an intermittent technology in the sense that the amount of electricity produced by the installed capacity is largely exogenous, dictated primarily by environmental conditions (especially the prevailing level of sunshine). In contrast, resources such as fuel cells, gas turbines, and reciprocating engines (which employ natural gas as the primary fuel) constitute non-intermittent DG technologies because the amount of electricity produced by the installed capacity is readily controlled.[8]

We begin by analyzing a setting in which smart meters are deployed ubiquitously and the regulator can set real-time retail prices and DG payments. In this setting, the retail prices for electricity and the unit payments for DG production are both set equal to the utility's prevailing marginal cost of generating electricity under an optimal policy. These retail prices and DG payments ensure the efficient consumption and production of electricity, given installed generating capacities. Unit charges on installed DG capacity that reflect the associated increase (or decrease) in the utility's transmission and distribution costs then induce efficient DG capacity investment. The identical retail prices and DG payments imply that net metering as described above is optimal. Furthermore, the ability to set different retail prices or DG payments for different consumers or for different DG technologies would not enhance consumer welfare.

We also consider a setting where the regulator can only establish time-of-use retail prices and time-of-production DG payments. These prices and payments can vary across pre-

payments are not feasible, and only one (fully intermittent) DG production technology is available.

[8]Solar panels account for the majority of DG capacity in most U.S. states, due in part to the rapid decline in the cost of solar panels in recent years (Barbose et al., 2014). However, natural gas-based DG configured in combined heat and power (CHP) mode account for the majority of DG capacity in Connecticut and New York (DNV GL, 2014). CHP units can be of particular value as a reliable alternative source of electricity when primary sources fail (U.S. Department of Energy, 2013).

specified time periods each day, but cannot vary within a time period. To induce desired levels of electricity consumption in this setting, the retail prices are set so that a weighted average of expected deviations of price from the utility's marginal cost of production is zero. In Ramsey-like fashion (Ramsey, 1927; Baumol and Bradford, 1970), the weights on deviations between price and cost reflect corresponding price sensitivities of the demand for electricity. To induce desired levels of electricity production from non-intermittent DG technologies, payments for such production are set equal to the utility's expected marginal cost of production during the relevant time period. To induce desired DG capacity investment, DG capacity charges are set to equate the consumer's marginal expected return from increasing DG capacity with the corresponding net reduction in the utility's production cost. This net reduction is the difference between the marginal reduction in the utility's expected generation costs and the marginal increase (or decrease) in the utility's transmission and distribution costs as DG capacity expands.

Because payments for DG production do not affect the amount of electricity produced with a given level of intermittent DG capacity, a regulator who can impose DG capacity charges has considerable flexibility in setting payments for electricity produced with the intermittent DG technology. In particular, the regulator can equate these payments either with the corresponding payments for electricity produced using the non-intermittent DG technology or with the corresponding retail rates for electricity. Consequently, neither a requirement to set the same DG payments for both technologies nor a requirement to implement the common net metering policy for the intermittent technology would be constraining in isolation. However, the imposition of both requirements simultaneously would reduce the level of welfare that can be secured for consumers.

The presence of social losses from externalities resulting from electricity production modify the foregoing findings in an intuitive fashion. In particular, retail electricity prices are optimally increased to discourage the purchase of electricity from the utility as the social losses from externalities associated with electricity production by the utility increase. In addition, DG payments for electricity produced using the non-intermittent technology increase as marginal social losses from externalities associated with this production decline relative to the marginal social losses associated with electricity production by the utility. Thus, more generous payments for electricity produced by "cleaner" DG technologies are optimal, *ceteris paribus*.

Overall, our findings imply that there is no single DG compensation policy that is optimal in all settings. The optimal policy varies with the instruments available to the regulator and with the relevant DG production technologies. Our findings also stress the important role of DG capacity charges. When these charges are feasible, the regulator can set them to induce efficient DG capacity investment while employing payments for DG production to induce efficient levels of electricity production, and net metering is optimal in certain settings. If the regulator is unable to impose capacity charges, then payments for DG production must serve to induce desired levels of both DG production and DG capacity investment. This dual role of payments for DG production complicates their design, limits the settings in which net metering is optimal, raises industry production costs, and reduces the level of welfare that can be secured for consumers.

We develop and explain these findings as follows. Section 2 presents the key features of our formal model. Section 3 characterizes the optimal policy in the setting where the regulator can set real-time retail prices and DG payments. Section 4 examines the changes to the optimal policy that arise in the presence of social losses from externalities. Section 5 identifies the key features of the optimal policy when the regulator can set time-of-use retail prices and time-of-production DG payments. Section 6 describes the optimal policy when the regulator's instruments are more limited, i.e., when retail rates cannot vary across demand periods or across customers, and when DG capacity charges are not feasible. Section 7 employs numerical solutions to illustrate how the optimal regulatory policy and industry outcomes change when the regulator is able to set DG capacity charges. Section 8 reviews the policy implications of our findings and suggests directions for further research.

2 Model Elements

A vertically-integrated producer (VIP) generates electricity, supplies it to consumers, and operates the sole transmission and distribution network.[9] There are two consumers, D and N, who purchase electricity from the VIP. Consumer D also can undertake distributed generation (DG) of electricity, whereas consumer N cannot do so.[10]

There are two periods of demand for electricity, denoted low (L) and high (H). Consumer $j \in \{D, N\}$ derives value $V_t^j(x, \theta_s)$ from x units of electricity in state $\theta_s \in [\,\underline{\theta}_t, \overline{\theta}_t\,]$ in period $t \in \{L, H\}$. This value is a strictly increasing, strictly concave function of x. The state variable θ_s can be viewed as a measure of the amount of sunshine that prevails at a specified time in the relevant period. Therefore, in hot climates for example, higher realizations of θ_s often will be associated with higher total and marginal valuations of electricity (to power cooling units).[11] The distribution function for the state variable in period t is $F_t(\cdot)$. The corresponding density function is $f_t(\cdot)$.

We will consider settings where the regulator can, and other settings where she cannot, set retail prices for electricity and payments for electricity produced via DG that vary with the realized state. In settings where the regulator can do so, $r_{jt}(\theta_s)$ will denote the retail price that consumer j must pay to the VIP for each unit of electricity he consumes in state θ_s in period t.[12] Consumer $j \in \{D, N\}$ also must pay the fixed charge R_j for the right to purchase electricity from the VIP.[13]

Consumer j's demand for electricity in state θ_s in period t is $X_t^j(r_{jt}(\theta_s), \mathbf{r_{jt'}}(\theta_{\mathbf{t'}}), \theta_s)$, where $\mathbf{r_{jt'}}(\theta_{\mathbf{t'}})$ is the vector of retail prices that consumer j might potentially face in period

[9]The setting we analyze also can be viewed as one in which the electricity supplier secures electricity via market transactions in a setting where a system operator dispatches supply in order of increasing cost.

[10]We assume there are only two consumers for expositional ease. Our qualitative conclusions are unchanged if there are multiple D consumers and multiple N consumers.

[11]Formally, in hot climates, $\frac{\partial V_t^j(x,\theta_s)}{\partial \theta_s} \geq 0$ and $\frac{\partial^2 V_t^j(x,\theta_s)}{\partial \theta_s \partial x} \geq 0$ for all $x \geq 0$ and $\theta_s \in [\,\underline{\theta}_t\,, \overline{\theta}_t\,]$, for $j \in \{D, N\}$. These inequalities need not hold more generally. The findings reported below hold even if these inequalities do not hold.

[12]In settings where the regulator cannot set state-specific prices, $r_{jt}(\theta_s) = r_{jt}(\theta_{s'})$ for all $\theta_s, \theta_{s'} \in [\,\underline{\theta}_t, \overline{\theta}_t\,]$.

[13]This formulation admits different retail prices for different consumers. The ensuing discussion also will consider settings in which such price discrimination is not feasible.

$t' \neq t$ $(t, t' \in \{L, H\})$, depending on the realization of the state variable.[14] Aggregate consumer demand in state θ_s in period t is $X_t(\cdot, \theta_s) = X_t^D(\cdot, \theta_s) + X_t^N(\cdot, \theta_s)$.

In addition to purchasing electricity from the VIP, consumer D can produce electricity himself and sell any excess of production over consumption to the VIP. Consumer D can produce electricity using an intermittent technology and/or a non-intermittent DG technology. The key difference between the technologies concerns the consumer's control over electricity production (dispatch) after installing generating capacity. For simplicity, we assume consumer D has no residual control over electricity produced using the intermittent DG technology (e.g., solar panels). Once he installs K_{Di} units of capacity of this technology, consumer D automatically produces $Q_t^i(K_{Di}, \theta_s) = \mu_t \, \theta_s \, K_{Di}$ units of electricity in state θ_s in period t at no incremental cost, where $\mu_t \geq 0$ is an efficiency parameter.[15] Thus, K_{Di} might be viewed as the number of solar panels of a fixed size that consumer D installs, and each panel produces more electricity as the amount of sunshine increases at a rate that the consumer cannot control.[16]

In contrast, the consumer can control the amount of electricity generated by the non-intermittent DG technology he installs (e.g., a combined heat and power unit powered by natural gas). Increased investment in this technology (K_{Dn}) reduces consumer D's variable and marginal cost of producing electricity in each demand period. Formally, $\frac{\partial C_t^D(Q_t^n, K_{Dn})}{\partial K_{Dn}} < 0$ and $\frac{\partial^2 C_t^D(\cdot)}{\partial K_{Dn} \partial Q_t^n} < 0$ for all $Q_t^n > 0$, where $C_t^D(Q_t^n, K_{Dn})$ is consumer D's variable cost of producing Q_t^n units of electricity in period $t \in \{L, H\}$ with the non-intermittent technology, given K_{Dn} units of capacity of the technology. This cost function is an increasing, convex function of Q_t^n.[17] Knowing this cost function and the prevailing payments for electricity pro-

[14] $X_t^j(r_{jt}(\theta_s), \mathbf{r_{jt'}}(\theta_{\mathbf{t'}}), \theta_s)$ is a strictly decreasing function of $r_{jt}(\theta_s)$ and a non-decreasing function of each element of $\mathbf{r_{jt'}}(\theta_{\mathbf{t'}})$. Here and throughout the ensuing analysis, we abstract from income effects in assuming that the fixed charge does not affect a consumer's demand for electricity.

[15] The precise placement of solar panels and the surrounding foliage or the adjacent structures at a specific location can cause electricity production to vary at different times of the day, holding constant the amount of sunshine that prevails in a geographic region.

[16] The presumed linear relationship between output and capacity is adopted for expositional simplicity and does not affect the qualitative conclusions drawn below.

[17] Formally, $\frac{\partial C_t^D(Q_t^n, K_{Dn})}{\partial Q_t^n} > 0$ and $\frac{\partial^2 C_t^D(Q_t^n, K_{Dn})}{\partial (Q_t^n)^2} > 0$ for all $Q_t^n \geq 0$.

duced using the non-intermittent capacity he has installed, consumer D chooses to produce the profit-maximizing level of electricity in each state.

Consumer D's cost of installing K_{Di} units of capacity of the intermittent DG technology and K_{Dn} units of capacity of the non-intermittent DG technology is $C_D^K(K_{Di}, K_{Dn})$, which is a strictly increasing function of each of its arguments. For analytic ease, we focus on settings where consumer D installs strictly positive levels of capacity of both DG technologies.[18]

The regulator specifies the compensation that the VIP must deliver to consumer D for the DG capacity he installs. k_{0y} is the fixed payment the VIP must make to consumer D when he installs any strictly positive amount of capacity in DG technology $y \in \{i, n\}$. k_y is the additional payment the VIP must make to consumer D for each unit of capacity of technology y he installs. These payments can be negative, in which case the VIP is authorized to impose capacity charges on consumer D.

The regulator also specifies the compensation the VIP must deliver to consumer D for the electricity he produces. $w_{yt}(\theta_s)$ is the payment the VIP must make to consumer D for each unit of electricity he produces using technology $y \in \{i, n\}$ in state θ_s in period t.[19]

The VIP's variable cost of generating Q_t^v units of electricity in period t when it has K_G units of generating capacity is $C_t^G(Q_t^v, K_G)$. Increased generating capacity reduces at a diminishing rate the VIP's variable and marginal cost of generating electricity.[20] The VIP's cost of installing K_G units of generating capacity is $C^K(K_G)$, which is an increasing, convex function.[21]

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[18]Consumer D will optimally do so in equilibrium if, for instance, $\underset{K_{Dy} \to 0}{limit} \frac{\partial C_D^K(\cdot)}{\partial K_{Dy}} = 0$ for $y \in \{i, n\}$ and $\underset{K_{Dn} \to 0}{limit} \left| \frac{\partial C_t^D(\cdot)}{\partial K_{Dn}} \right| = \infty$ for $t \in \{L, H\}$.

[19]The VIP must make this payment to consumer D regardless of whether consumer D consumes the unit of electricity in question. Recall that consumer D must pay the prevailing retail charge for each unit of electricity he consumes, regardless of the source of the electricity. Thus, the common net metering policy prevails if $w_{yt}(\theta_s) = r_{jt}(\theta_s)$ in each period t and state θ_s, for both technologies ($y \in \{i, n\}$) and both consumers ($j \in (D, N\}$).

[20]Formally, $\frac{\partial C_t^G(Q_t^v, K_G)}{\partial K_G} < 0$, $\frac{\partial^2 C_t^G(Q_t^v, K_G)}{\partial Q_t^v \partial K_G} < 0$, and $\frac{\partial^3 C_t^G(Q_t^v, K_G)}{\partial Q_t^v \partial^2 K_G} > 0$ for all $Q_t^v > 0$.

[21]Formally, $C^{K\prime}(K_G) > 0$ and $C^{K\prime\prime}(K_G) > 0$. We also assume a strictly positive level of generating capacity is optimal. This will be the case if, for example, $\underset{K_G \to 0}{limit} \left| \frac{\partial C_t^G(Q_t^v, K_G)}{\partial K_G} \right| = \infty$ and $\underset{K_G \to 0}{limit} C^{K\prime}(K^G) = 0$.

The VIP also incurs transmission and distribution (T&D) costs $T(K_G, K_{Di}, K_{Dn})$ to support centralized and distributed generating capacities K_G, K_{Di}, and K_{Dn}.[22] For simplicity, we abstract from variable T&D costs associated with line losses that might arise even when adequate infrastructure is implemented to fully accommodate electricity produced by the installed generating capacity.[23]

The regulator chooses her policy instruments to maximize the sum of the expected welfare of consumer N and consumer D, subject to ensuring non-negative expected profit for the VIP. The regulator's policy instruments are the retail prices for electricity, the terms of the DG compensation the VIP must deliver to consumer D, and the VIP's generating capacity.

Consumer N's welfare ($U^N(\cdot)$) is the difference between the value he derives from the electricity he consumes and the amount he pays for the electricity. Formally, consumer N's expected welfare is, for $t' \neq t$ ($t, t' \in \{L, H\}$):

$$
\begin{aligned}
E\left\{ U^N(\cdot) \right\} \;=\; \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\bar{\theta}_t} & \left[V_t^N(X_t^N(r_{Nt}(\theta_s), \mathbf{r_{Nt'}}(\theta_{\mathbf{t'}}), \theta_s), \theta_s) \right. \\
& \left. -\; r_{Nt}(\theta_s)\, X_t^N(\cdot) \right] dF_t(\theta_s) - R_N \,. \qquad (1)
\end{aligned}
$$

Consumer D's welfare ($U^D(\cdot)$) is the sum of the value he derives from the electricity he consumes and the compensation he receives for installing DG capacity and producing electricity, less the amount he pays for the electricity he purchases from the VIP and his costs of DG investment and production. Formally, consumer D's expected welfare is, for $t' \neq t$ ($t, t' \in \{L, H\}$):

$$
\begin{aligned}
E\left\{ U^D(\cdot) \right\} \;=\; \sum_{t \in \{L,H\}} \Bigg[& \int_{\underline{\theta}_t}^{\bar{\theta}_t} \left[V_t^D(X_t^D(r_{Dt}(\theta_s), \mathbf{r_{Dt'}}(\theta_{\mathbf{t'}}), \theta_s), \theta_s) - \; r_{Dt}(\theta_s)\, X_t^D(\cdot) \right] dF_t(\theta_s) \\
& + \int_{\underline{\theta}_t}^{\bar{\theta}_t} \left[w_{it}(\theta_s)\, Q_t^i(K_{Di}, \theta_s) + w_{nt}(\theta_s)\, Q_t^n(K_{Dn}, \theta_s) - C_t^D(Q_t^n(\cdot, \theta_s), K_{Dn}) \right] dF_t(\theta_s) \Bigg]
\end{aligned}
$$

[22]For expositional ease, the ensuing discussion focuses on settings where $T(\cdot)$ is increasing in each of its arguments. Section 7 explicitly considers settings where DG capacity investments reduce the VIP's T&D costs.

[23]These losses are relatively small in practice (Parsons and Brinckerhoff, 2012; U.S. Energy Information Administration (EIA), 2014b). Explicit accounting for these variable costs would not affect the key qualitative conclusions reported below.

$$+\ k_{0i} + k_{0n} + k_i\, K_{Di} + k_n\, K_{Dn} - C_D^K(K_{Di}, K_{Dn}) - R_D\,,$$

$$\text{where}\ \ Q_t^n(\cdot, \theta_s)\ =\ \arg\max_Q\ \left\{ w_{nt}(\theta_s)\, Q - C_t^D(Q, K_{Dn}) \right\}. \tag{2}$$

The VIP's profit (π) is the revenue it secures from selling electricity to consumers D and N, less the sum of: (i) the DG compensation it pays to consumer D; (ii) the cost of its generating capacity; (iii) its cost of generating electricity; and (iv) its T&D costs. Formally, the VIP's expected profit is:

$$\begin{aligned} E\{\pi\} \ =\ & \sum_{t\in\{L,H\}} \left[\int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[r_{Dt}(\theta_s)\, X_t^D(\cdot) + r_{Nt}(\theta_s)\, X_t^N(\cdot) - w_{it}(\theta_s)\, Q_t^i(K_{Di}, \theta_s) \right.\right. \\ & \left.\left. -\ \ w_{nt}(\theta_s)\, Q_t^n(K_{Dn}, \theta_s) - C_t^G(Q_t^v(\cdot), K_G) \right] dF_t(\theta_s) + R_D + R_N \right. \\ & -\ \ k_{0i} - k_{0n} - k_i\, K_{Di} - k_n\, K_{Dn} - C^K(K_G) - T(K_G, K_{Di}, K_{Dn})\,. \end{aligned} \tag{3}$$

The timing in the model is as follows. The regulator first sets her policy instruments. Consumer D then chooses his DG capacity investments. Finally, the state is realized, DG production occurs, and the VIP supplies the realized demand for electricity and provides all required T&D of electricity in each demand period.[24]

3 State-Specific Pricing and DG Compensation

We first examine the optimal regulatory policy in a setting where smart meters are deployed ubiquitously and the regulator can set prices and DG payments that vary with the realization of the state variable in each period. The regulator's problem in this setting, [RP-θ], is:

$$\underset{r_{jt}(\theta_s),\, R_j,\, k_{0y},\, k_{yt},\, w_{yt}(\theta_s),\, K_G}{Maximize} \quad E\left\{ U^N(\cdot) \right\} + E\left\{ U^D(\cdot) \right\} \tag{4}$$

$$\text{subject to:}\ \ E\{\pi\}\ \geq\ 0\,, \tag{5}$$

where $E\left\{ U^N(\cdot) \right\}$, $E\left\{ U^D(\cdot) \right\}$, and $E\{\pi\}$ are as defined in (1), (2), and (3), respectively.

Proposition 1 characterizes the key features of the optimal regulatory policy in this setting.

[24] The sequencing of the two demand periods does not affect our findings.

Proposition 1. *At a solution to [RP-θ]: (i)* $\sum\limits_{t\,\in\,\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left| \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial K_G} \right| dF_t(\theta_s) = C^{K\prime}(K_G)$ $+\frac{\partial T(\cdot)}{\partial K_G}$ *; (ii)* $r_{Nt}(\theta_s) = r_{Dt}(\theta_s) = w_{nt}(\theta_s) = w_{it}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)}$ *for each* $t \in \{L,H\}$ *and* $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$*; and (iii)* $k_y = -\frac{\partial T(\cdot)}{\partial K_{Dy}}$ *for* $y \in \{\, i, \, n \,\}$.

Conclusion (i) in Proposition 1 indicates that the VIP's generating capacity is chosen to minimize the VIP's expected operating costs. In particular, this capacity is optimally increased to the point where the rate at which additional capacity reduces the VIP's expected generation costs is equal to the rate at which increased capacity increases the sum of the VIP's capacity costs and associated T&D costs.

Conclusion (ii) indicates that the unit retail price of electricity and the unit payment for DG production are both optimally set equal to the VIP's marginal cost of generating electricity in each state. These prices and payments ensure that consumers expand their consumption of electricity to the point where its marginal value is equal to its marginal cost of production in each state, regardless of the dispatachable (non-intermittent) source of production. Thus, the identified retail prices and DG payments ensure the efficient consumption and production of electricity, given installed generating capacities.[25]

Conclusion (iii) reports that the optimal unit DG capacity charge is the associated marginal increase in the VIP's T&D costs, which can vary by technology.[26] When he is compensated for the electricity he produces using the non-intermittent technology at a rate that reflects the VIP's marginal cost of generating electricity, consumer D will install the efficient level of K_{Dn} when he is required to bear the associated increment in the VIP's T&D costs.[27] In essence, this charge (and the associated payments for DG production) induce

[25]The fixed retail charges (R_j) are set to ensure the VIP earns zero expected profit.

[26]The increase in the VIP's T&D costs also can vary substantially across geographic regions. See Shlatz et al. (2013) and Cohen et al. (2015), for example.

[27]The values of $w_{it}(\theta_s)$ and k_i identified in Proposition 1 are not unique because the values of $w_{it}(\theta_s)$ do not affect the amount of electricity produced by the installed intermittent capacity. If the $w_{it}(\theta_s)$ payments are increased above $\frac{\partial C_t^G}{\partial Q_t^v}$, then k_i can be reduced accordingly to ensure consumer D installs the efficient level of intermittent DG capacity.

consumer D to account fully for the relevant expected social benefits and costs of investment in DG capacity.

The fact that the unit payment for DG production and the unit retail price of electricity are equated under the optimal policy identified in Proposition 1 has three important implications. First, net metering (as described in the Introduction) can be optimal for both DG technologies. Second, there is no strict gain from implementing DG compensation that varies by technology. Third, there is no strict gain from setting distinct retail prices for different consumers.[28] In this sense, when state-specific retail pricing and DG payments are feasible, relatively simple DG payment policies can secure the ideal outcome for consumers.

4 Externalities

The analysis to this point has abstracted from social losses due to externalities associated with the generation of electricity. To account for these losses, let $S_t(Q_t^v, Q_t^i, Q_t^n)$ denote the social loss from environmental externalities in period t when the VIP produces output Q_t^v and when consumer D produces output Q_t^i with the intermittent technology and output Q_t^n with the non-intermittent technology.[29] Define $S_{th}(\cdot) \equiv \frac{\partial S_t(\cdot)}{\partial Q_t^h} \geq 0$ for $h \in \{v, i, n\}$. The regulator's problem in this setting, [RP-θe], is to:

$$\underset{r_{jt}(\theta_s),\, R_j,\, k_{0y},\, k_{yt},\, w_{yt}(\theta_s),\, K_G}{Maximize} \quad E\left\{ U^N(\cdot) \right\} + E\left\{ U^D(\cdot) \right\} - E\left\{ S_L(\cdot) + S_H(\cdot) \right\} \tag{6}$$

$$\text{subject to:} \quad E\{ \pi \} \geq 0 , \tag{7}$$

where $E\left\{ U^N(\cdot) \right\}$, $E\left\{ U^D(\cdot) \right\}$, and $E\{ \pi \}$ are as defined in (1), (2), and (3), respectively.

Proposition 2. *At a solution to [RP-θe], conclusions (i) and (iii) in Proposition 1 hold. In addition,* $r_{Nt}(\theta_s) = r_{Dt}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} + S_{tv}(\cdot)$ *and* $w_{yt}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} + S_{tv}(\cdot) - S_{ty}(\cdot)$ *for all* $t \in \{L, H\}$, $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$, *and* $y \in \{i, n\}$.

[28] Retail charges that differ across consumers can be optimal if the regulator values the welfare of consumer N differently from the welfare of consumer D.

[29] For simplicity, we assume the social loss from externalities in one period does not vary with outputs produced in the other period. We also assume the total social loss from externalities is the sum of the corresponding losses in each period.

Proposition 2 reports that in order to induce efficient electricity consumption in the presence of externalities, it is optimal to raise the unit retail price of electricity above the VIP's marginal cost of production by the marginal social loss from externalities associated with the VIP's production of electricity ($S_{tv}(\cdot)$). Further, to induce consumer D to produce the efficient amount of electricity using the non-intermittent technology, it is optimal to increase the corresponding unit DG payment ($w_{nt}(\theta_s)$) above the VIP's marginal cost of production by the difference between the marginal social loss from externalities due to production by the VIP and by consumer D ($S_{tv}(\cdot) - S_{tn}(\cdot)$). Thus, DG compensation is increased to the extent that the DG generation technology is "cleaner" than the VIP's generation technology, *ceteris paribus*.[30]

Proposition 2 implies that net metering generally is optimal only for electricity produced using a DG technology that generates no social losses from externalities. When retail prices are increased above the VIP's marginal cost by $S_{tv}(\cdot)$ and unit DG payments are increased above the VIP's marginal cost by $S_{tv}(\cdot) - S_{ty}(\cdot)$, the retail prices and DG payments will coincide only if $S_{ty}(\cdot) = 0$. Thus, net metering may be optimal for solar DG production if it generates no social losses from externalities. In contrast, net metering generally is not optimal for DG production using CHP units, for example. Furthermore, even abstracting from differences in generating costs, optimal retail prices typically will vary with the VIP's generating technology. In addition, optimal DG payments typically will vary with the generating technologies employed by both the VIP and consumer D.

5 TOU Pricing and TOP DG Compensation

In practice, smart meters are not always deployed and employed ubiquitously. Consequently, state-specific retail prices and DG payments are not always feasible. In light of this fact, we now consider the setting where the regulator implements time of use (TOU) retail prices and time of production (TOP) DG payments (in addition to DG capacity charges).

[30] Again, the values of $w_{it}(\theta_s)$ and k_i identified in Proposition 2 are not unique because the $w_{it}(\theta_s)$ payments do not affect consumer D's production of electricity using the intermittent DG technology, given installed capacity K_{Di}.

In this setting, the regulator can specify four distinct unit retail prices and four distinct DG payments. The retail prices can vary by customer and by demand period, but cannot vary within a period. The DG payments can vary by DG technology and by demand period, but cannot vary within a demand period. Formally, when only TOU retail prices and TOP DG payments are feasible, for $y \in \{i, n\}$ and $t \in \{L, H\}$:

$$r_{jt}(\theta_s) \;=\; r_{jt}(\theta_{s'}) \;\equiv\; r_{jt} \;\text{ and }\; w_{yt}(\theta_s) \;=\; w_{yt}(\theta_{s'}) \;\equiv\; w_{yt} \;\text{ for all }\; \theta_s,\, \theta_{s'} \,\in\, [\,\underline{\theta}_t,\, \overline{\theta}_t\,]\,. \quad (8)$$

[RP-t] will denote the regulator's problem in this setting with TOU retail pricing and TOP DG payments. Formally, [RP-t] is problem [RP-θ] with the additional restrictions specified in condition (8). Thus, for expositional clarity, we abstract from social losses from externalities.[31] Proposition 3 characterizes the key features of the optimal regulatory policy in this setting.

Proposition 3. *At the solution to [RP-t]:*

$$\text{(i)} \quad \sum_{t\in\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left| \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial K_G} \right| dF_t(\theta_s) \;=\; C^{K\prime}(K_G) + \frac{\partial T(\cdot)}{\partial K_G}\,;$$

$$\text{(ii)} \quad \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[r_{jt} - \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)} \right] \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}}\, dF_t(\theta_s)$$

$$+ \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'} - \frac{\partial C_t^G(Q_t^v(\cdot,\theta_{s'}),K_G)}{\partial Q_t^v(\cdot,\theta_{s'})} \right] \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}}\, dF_{t'}(\theta_{s'}) \;=\; 0 \;\; \textit{for } t' \neq t,\;\; t,t' \in \{L,H\};$$

$$\text{(iii)} \quad w_{nt} \;=\; \int_{\underline{\theta}_t}^{\overline{\theta}_t} \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)}\, dF_t(\theta_s) \;\; \textit{for } t \,\in\, \{\,L,\, H\,\}\,; \;\; \textit{and}$$

$$\text{(iv)} \quad k_y \;=\; \sum_{t\in\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)} - w_{yt} \right] \frac{\partial Q_t^y(\cdot,\theta_s)}{\partial K_{Dy}}\, dF_t(\theta_s) - \frac{\partial T(\cdot)}{\partial K_{Dy}}$$

for $y \,\in\, \{\,i,\, n\,\}$.

Conclusion (i) in Proposition 3 again indicates that the VIP's generation capacity (K_G)

[31] Proposition 6 in the Appendix identifies how social losses from externalities affect the optimal regulatory policy in the present setting.

is chosen to minimize the VIP's expected operating costs, which include generation costs, capacity costs, and T&D costs.

Conclusion (ii) reports that the unit retail prices for electricity are set so that expected weighted deviations of prices from the incumbent's marginal cost of generating electricity are zero. Deviations of price from marginal cost are weighted more heavily when consumer demand is more sensitive to price, as under Ramsey pricing (Ramsey, 1927; Baumol and Bradford, 1970). Because price sensitivity can vary between consumers and across demand periods, the regulator typically is able to secure a strictly higher level of expected consumer welfare when she is able to set prices and DG payments that vary across consumers and across demand periods.

Conclusion (iii) implies that the unit compensation for non-intermittent DG production in period t is optimally set equal to the VIP's expected marginal cost of generating electricity in period t. By rewarding consumer D for increased DG production at a rate that reflects the associated expected reduction in the VIP's generation costs, the regulator encourages consumer D to expand his production of electricity from the non-intermittent DG technology to the level that minimizes expected industry generation costs, given installed generation capacities.

Conclusion (iv) indicates that the unit compensation (k_n) for non-intermittent DG investment (K_{Dn}) is optimally set to induce consumer D to choose the level of K_{Dn} that minimizes expected industry costs, given K_G and K_{Di}. This is accomplished by setting k_n to equate consumer D's expected marginal benefit from increasing K_{Di} (i.e., $k_n + \sum_{t \in \{L,H\}} w_{nt} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial K_{Dn}} dF_t(\theta_s)$) with the corresponding expected marginal net reduction in the VIP's costs, which is the difference between the expected marginal reduction in the VIP's generating costs ($\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \left| \frac{\partial Q_t^v}{\partial K_{Dn}} \right| dF_t(\theta_s)$) and the marginal increase in the VIP's T&D costs ($\frac{\partial T(\cdot)}{\partial K_{Dn}}$).

Conclusions (iii) and (iv) together imply that the unit capacity charge ($-k_n$) is set to induce the desired capacity investment in the non-intermittent DG technology (K_{Dn}), given

DG payments (w_{nL} and w_{nH}), whereas these payments are set to induce the desired level of electricity production, given the installed capacity investment (K_{Dn}).

Conclusion (iv) also reports that the compensation consumer D anticipates for installing intermittent DG capacity (K_{Di}) and producing electricity using this capacity is set to ensure the consumer chooses the level of K_{Di} that minimizes expected industry production costs, given K_G and K_{Dn}.[32] Because consumer D cannot control the amount of electricity produced by each unit of capacity of the intermittent technology, the corresponding unit DG compensation levels (w_{iL} and w_{iH}) do not affect electricity production, given installed capacity K_{Di}. Consequently, the regulator has considerable leeway in setting w_{iL}, w_{iH}, and k_i to jointly induce the desired K_{Di} capacity investment. In particular, the regulator can set $w_{iL} = w_{nL}$ and $w_{iH} = w_{nH}$ and adjust k_i to induce the desired level of K_{Di}. Therefore, the regulator derives no strict gain from an ability to set technology-specific payments for DG production of electricity in this setting with TOU retail prices and TOP DG compensation.[33]

6 Settings with More Restricted Policy Instruments

The preceding analysis assumes the regulator can set retail prices that differ across consumers and across demand periods. It also assumes the regulator can both set payments for DG production of electricity and specify compensation (or charges) for DG capacity investment. We now briefly illustrate how the optimal policy changes when the regulator's policy instruments are more limited.

6.1 No Customer-Specific Pricing

First consider the optimal regulatory policy when the regulator can set: (i) a single fixed retail charge for electricity (R) for both consumers; (ii) a single unit retail price (r) of electricity that the two consumers face throughout both demand periods; (iii) a single technology-specific unit payment for DG production (w_y for $y \in \{i, n\}$) that prevails in both

[32]Because the VIP generates the difference between the quantity of electricity demanded and the quantity supplied by consumer D, $\frac{\partial Q_t^v}{\partial Q_t^i} = -1$ and so $\frac{\partial Q_t^v}{\partial Q_t^i} \frac{\partial Q_t^i(\cdot, \theta_s)}{\partial K_{Di}} = -\mu_t \, \theta_s$.

[33]This conclusion does not hold if there is more than one DG technology for which consumer D can exercise non-trivial control over the amount of DG production, given the prevailing capacity investments.

demand periods; and (iv) technology-specific unit compensation (or charges) for DG capacity (k_i and k_n). Let [RP] denote the regulator's problem in this setting.

Proposition 4. *At a solution to [RP]: (i)* $\sum_{j\in\{D,N\}}\sum_{t\in\{L,H\}}\int_{\underline{\theta}_t}^{\overline{\theta}_t}\left[r-\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)}\right]\frac{\partial X_t^j(\cdot,\theta_s)}{\partial r}\,dF_t(\theta_s)=0$*; (ii)* $w_n=\sum_{t\in\{L,H\}}\int_{\underline{\theta}_t}^{\overline{\theta}_t}\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)}\,dF_t(\theta_s)$*; and (iii)* $k_y=\sum_{t\in\{L,H\}}\int_{\underline{\theta}_t}^{\overline{\theta}_t}\left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)}-w_y\right]\frac{\partial Q_t^y(K_{Dy},\theta_s)}{\partial K_{Dy}}\,dF_t(\theta_s)-\frac{\partial T(\cdot)}{\partial K_{Dy}}$ *for* $y\in\{i,n\}$.[34]

A comparison of Propositions 3 and 4 reveals that similar considerations underlie the optimal regulatory policy regardless of the regulator's ability to set different prices for different customers or in different demand periods. Conclusion (i) in Proposition 4 indicates that the regulator optimally sets the constant unit retail price of electricity (r) so that the expected weighted deviations between r and the VIP's marginal cost of generating electricity are zero. The weights again reflect the sensitivity of consumer demand to price (for both consumers and in both demand periods).

Conclusion (ii) reports that the optimal unit payment for electricity produced with the non-intermittent technology is equal to the VIP's expected marginal cost of generating electricity (in both demand periods). Conclusion (iii) states that the optimal compensation for DG capacity investment ensures that consumer D's marginal expected return to increasing the capacity of each technology is equal to the corresponding marginal reduction in the VIP's costs (which include both generation costs and T&D costs).

Because the established value of w_i does not affect the amount of electricity produced from a given investment in the capacity of the intermittent technology (K_{Di}), the regulator can set $w_i = r$ and adjust k_i accordingly to induce the optimal K_{Di} investment. Consequently, net metering for electricity produced with the intermittent DG technology can be optimal. In contrast, net metering for electricity produced with the non-intermittent DG technology generally is not optimal, even in the absence of social losses from externalities.

[34]Conclusion (i) in Proposition 3 also holds and the VIP earns zero expected profit at the solution to [RP].

6.2 No DG Capacity Charges

Although DG capacity charges have been proposed in several jurisdictions, they are not presently deployed ubiquitously.[35] When a regulator is unable to implement capacity charges, she must employ payments for DG production to induce desired investment in DG capacity. Consequently, it typically is no longer optimal to set these payments to induce efficient levels of DG electricity production, given installed generating capacities. To illustrate this more general conclusion, consider the setting with state-specific retail prices and DG payments analyzed in section 3, with the exception that the regulator cannot impose any capacity charges (so $k_{0y} = k_{yt}(\theta_s) = 0$ for all $y \in \{i, n\}$, $t \in \{L, H\}$, and $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t])$. Let [RP-$\theta k$] denote the regulator's problem in this setting.

Proposition 5. *At a solution to [RP-θk], for all $t \in \{L, H\}$ and $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$: (i) $r_{Dt}(\theta_s) = r_{Nt}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)}$; and (ii) $w_{yt}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} - \frac{\partial T(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} \left[\left(\frac{\partial Q_t^y(\cdot,\theta_s)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} + \frac{\partial Q_t^y(\cdot,\theta_s)}{\partial w_{yt}(\theta_s)} \right) f_t(\theta_s) \right]^{-1}$ for $y \in \{i, n\}$.*[36]

Conclusion (i) in Proposition 5 indicates that in order to induce the efficient consumption of electricity, the regulator sets the retail price of electricity equal to the VIP's marginal cost of generating electricity in each state in each demand period. To induce consumer D to produce the efficient level of electricity using the non-intermittent technology, the regulator would like to set each $w_{nt}(\theta_s)$ payment at this same level. However, these payments would induce consumer D to install more than the efficient level of capacity of the non-intermittent technology in the absence of a DG capacity charge that reflects the increase in T&D costs the VIP experiences as K_{Dn} increases. Consequently, as conclusion (ii) in Proposition 5 indicates, the regulator optimally reduces the $w_{nt}(\theta_s)$ payments below $\frac{\partial C_t^G(\cdot)}{\partial Q_t^v}$. The amount of the reduction is proportional to the rate at which an increase in the DG payment increases

[35] DG capacity charges have been proposed in Arizona, Hawaii, Kansas, Maine, New Mexico, Oklahoma, Utah, and Wisconsin (NCCETC, 2015d).

[36] Conclusion (i) in Proposition 1 also holds and the VIP earns zero expected profit at the solution to [RP-θk].

the VIP's T&D costs per corresponding unit of increased DG output.[37,38]

Proposition 5 indicates that, in contrast to the setting where the regulator can set DG capacity charges, net metering ($w_{yt}(\theta_t) = r_{yt}(\theta_t)$) is not optimal for either technology, even in the absence of social losses from externalities. Thus, although such relatively simple DG payments can be optimal when the regulator has access to a full array of policy instruments, these payments typically are not optimal when the regulator's instruments are more limited, and so she must employ DG payments both to induce desired DG capacity investment and to affect DG electricity production given the installed capacities.

7 Illustrating the Impact of Capacity Charges

We now present numerical solutions to illustrate how the ability to set capacity charges affects the optimal regulatory policy and the financial returns from undertaking DG. For simplicity, we assume there is a single demand period each day and consumer demand for electricity is iso-elastic,[39] so consumer j's demand for electricity in state θ with retail price r is $X^j(r, \theta) = m_j \, [\, 1 + \theta \,] \, r^{\alpha_j}$, where $m_j > 0$ and $\alpha_j < 0$ for $j \in \{D, N\}$.[40] We assume the price

[37] The numerator of the last term in conclusion (ii) in Proposition 5 for $y = n$ is the rate at which the VIP's T&D costs increases as $w_{nt}(\theta_s)$ increases due to the induced increase in K_{Di}. The denominator of this term reflects the rate at which output produced using the non-intermittent DG technology ($Q_t^n(\cdot)$) increases as $w_{nt}(\theta_s)$ increases. The increase in $Q_t^n(\cdot)$ arises from two sources. First, the increase in $w_{nt}(\theta_s)$ induces consumer D to increase K_{Dn}, which reduces the consumer's marginal cost of producing electricity, which in turn induces increased production. Second, the increase in $w_{nt}(\theta_s)$ increases the prevailing rate of compensation for electricity production, which induces increased production. The corresponding interpretation when $y = i$ is analogous except that an increase in $w_{it}(\theta_s)$ only affects the amount of electricity produced using the intermittent DG technology by inducing consumer D to increase K_{Di} (i.e., $\frac{\partial Q_t^i(\cdot, \theta_s)}{\partial w_{it}(\theta_s)} = 0$).

[38] The central considerations that underlie the findings in Proposition 5 persist in other settings where the regulator's instruments are more limited (e.g., where she can only set TOU retail prices and TOP DG payments).

[39] We also assume the regulator cannot impose fixed, state-specific, or customer-specific retail charges. She also cannot implement state-specific DG capacity charges or fixed DG charges that do not vary with the level of installed capacity. The regulator seeks to maximize expected consumer welfare while ensuring nonnegative expected profit for the VIP.

[40] This relationship is assumed to hold for $r \le r^m$. We assume $X^j(\cdot) = 0$ for $r > r^m$ to ensure finite values for $E\{U^j\}$, $j \in \{D, N\}$. We set $r^m = 800$, reflecting particularly high estimates of customer valuations of lost load (London Economics International, 2013). Results similar to those reported below hold if the more general iso-elastic demand function $X^j(r, \theta) = m_j \, [\, 1 + \theta^s \,] \, r^{\alpha_j}$ is employed, where s differs from 1.

elasticity of demand for electricity is -0.25 for both consumers, so $\alpha_D = \alpha_N = -0.25$.[41]

We begin by considering a "baseline" setting in which the VIP primarily employs non-coal resources to serve a relatively large number of customers, as in California, for example.[42] In this setting, the demand parameters m_D and m_N are chosen to equate the equilibrium expected demand in the model with $\overline{X} = 25,391$ (MWh), the average hourly consumption of electricity in California in 2014.[43] Formally, m_j is chosen to ensure $E\{m_j[1+\theta]\widetilde{r}^{\alpha_j}\} = \eta_j \overline{X}$ for $j \in \{D, N\}$, where η_D denotes the fraction of demand accounted for by customers who undertake some distributed generation of electricity, $\eta_N = 1 - \eta_D$, and $\widetilde{r} = 143.8165$ reflects the average unit retail price of electricity (\$/MWh) in California in 2014 (California Public Utilities Commission, 2015). We initially assume $\eta_D = 0.1$ to reflect the potential deployment of PV panels in the U.S. in the near future.[44]

Recall that the distribution of the state variable (θ) reflects variation in the production of electricity from installed DG capacity. To specify this distribution, we first plot the ratio of the MW's of electricity produced by photo-voltaic (PV) panels to the year-end installed generating capacity ($\overline{K}_D = 3,254$ MW) of PV panels in California for each of the $8,760$ hours in 2014.[45] We then employ maximum likelihood estimation to fit a density function to

[41] Estimates of the short-run price elasticity of demand for electricity for residential consumers range from -0.13 (Paul et al., 2009) to -0.35 (Espey and Espey, 2004). Corresponding long-run estimates reflect more elastic demand (e.g., between -0.40 (Paul, 2009) and -0.85 (Espey and Espey, 2004)). Commercial and industrial customers typically exhibit less elastic demands for electricity (e.g., Wade, 2003; Taylor et al., 2005; Paul et al., 2009). Brown and Sappington (2016) demonstrate how the optimal regulatory policy changes as this parameter and other parameters change. The qualitative results presented in this section generally are robust to considerable variation in parameter values.

[42] The ensuing calculations are not intended to characterize actual or likely outcomes in California or any other specific jurisdiction However, the California data is useful in modeling a setting where a VIP generates a relatively large amount of electricity employing primarily non-coal resources.

[43] $\overline{X}$ is the sum of: (i) $\overline{Q}_v = 24,577$ MWh, the average amount of electricity sold hourly by California utilities in 2014 (California Independent System Operator (CAISO), 2015a); and (ii) the estimated average hourly electricity generated from solar DG in California in 2014. This latter estimate is 25.0% of $\overline{K}_D$, the $3,254$ MW of PV capacity installed in California at year end 2014 (California Solar Statistics, 2015). The 25.0% reflects the utilization rate of solar DG capacity in California (CAISO, 2015b).

[44] 10.6% of consumers undertook some DG of electricity in Hawaii in 2014. The corresponding percentages are 2% in California and 1.6% in Arizona (EIA, 2015b). Schneider and Sargent (2014) report rapid growth in the installation of solar panels in recent years.

[45] The data on PV output are derived from CAISO (2015b).

the 4,443 (49.4%) of the observations that are strictly positive. Standard tests reveal that the beta distribution with parameters $(1.165, 1.204855)$ fits the data well, and so is used as the density function for θ in the ensuing analysis.[46]

The VIP's capacity costs are taken to be quadratic, i.e., $C^K(K_G) = a_K\, K_G + b_K\, (K_G)^2$. Estimates of the cost of the generation capacity required to produce a MWh of electricity range from \$16.1/MWh for a conventional combined cycle natural gas unit to \$81.9/MWh for a nuclear facility (EIA, 2015a). We set a_K at the lower bound of this range (16.1). We also set $b_K = 0.00045$ to ensure that the marginal cost of capacity required to generate a MWh of electricity is \$81.9 at the observed level of centralized non-renewable generation capacity in California in 2014 ($\overline{K}_G = 72,926$ MW) (California Energy Commission, 2015).

For simplicity, the VIP's T&D costs are assumed to be linear, i.e., $T(K_G, K_{Di}, K_{Dn}) = a_T^G\, K_G + a_T^{Di}\, K_{Di} + a_T^{Dn}\, K_{Dn}$. Estimates of these costs vary widely. EIA (2015a) estimates utility transmission capacity costs associated with generating a MWh of electricity are between \$1.2 and \$3.5 for centralized, non-renewable generation, and between \$4.1 and \$6.0 for PV generation. Reflecting the midpoints of these cost estimates, we initially assume $a_T^G = 2.35$ and $a_T^{Di} = a_T^{Dn} = 5.05$.[47]

We assume the VIP's cost of generating Q^v units of electricity when it has K_G units of capacity to be $C^G(Q^v, K_G) = \left[a_v + \frac{c_v}{K_G} \right] Q^v + b_v\, (Q^v)^2$, where a_v, b_v, and c_v are positive constants. Thus, increased capacity reduces the VIP's cost of generating electricity at a diminishing rate.[48] We set $b_v = 0.003$ and $a_v + \frac{c_v}{K_G} = 28.53$, reflecting Bushnell (2007)'s estimates.[49] c_v is chosen to equate the observed marginal benefit $(\frac{c_v\, \overline{Q}^v}{(\overline{K}_G)^2})$ and marginal cost

[46] The chi-squared, Kolmogorov-Smirnov, and Anderson-Darling tests also reveal that the generalized extreme value (GEV) distribution with parameter values $(0.4827, 0.3088, -0.7135)$ fits the data reasonably well. Findings very similar to those reported below arise when this GEV distribution replaces the identified beta distribution.

[47] Alternative estimates for these parameters are considered below.

[48] Formally, $\frac{\partial C^G(\cdot)}{\partial K_G} = -\frac{c_v Q^v}{(K_G)^2} < 0$ and $\frac{\partial^2 C^G(\cdot)}{\partial (K_G)^2} = \frac{2\, c_v Q^v}{(K_G)^3} > 0$, which implies $\frac{\partial}{\partial K_G} \left| \frac{\partial C^G(\cdot)}{\partial K_G} \right| < 0$.

[49] Employing a cost function of the form $C(Q^v) = a\, Q^v + b(Q^v)^2$, Bushnell (2007) estimates $a = 28.53$ and $b = 0.003$.

$(a_K + 2\, b_K\, \overline{K}_G + a_T^G\,)$ of VIP capacity.[50]

The cost of installing K_{Di} units of intermittent DG capacity and K_{Dn} units of non-intermittent DG capacity is assumed to be $C_D^K(K_{Di}, K_{Dn}) = a_{Di}\, K_{Di} + b_{Di}\,(K_{Di})^2 + a_{Dn}\, K_{Dn} + b_{Dn}\,(K_{Dn})^2$. Estimates of the unsubsidized cost of residential PV capacity vary between \$100 and \$400/MWh (Branker et al., 2011; EIA, 2015a). When the 30 percent federal income tax credit (ITC) is applied, these estimates decline to between \$70 and \$280/MWh. State subsidies further reduce these estimates to between \$45 and \$255/MWh (NCCETC, 2015a,b,c). We initially set $a_{Di} = 150$, the midpoint of this lattermost range. We also set $b_D = 0.0038$ to ensure ensure that the marginal cost of DG capacity when $K_{Di} = \overline{K}_D = 3,254$ (i.e., $a_D + 2\, b_D\, \overline{K}_D$) is 175, the midpoint of the range of estimated costs after applying the ITC.

Estimates of the cost of DG capacity using natural gas reciprocating engine and gas turbines range from \$34.09 to \$52.81/MWh (PacifiCorp, 2013). We set a_{Dn} equal to the lower bound of this range (34.09) and select b_{Dn} to ensure the marginal cost of capacity at the level of combined heat and power (CHP) DG in California, $\overline{K}_{Dn} = 8,518$ MW (ICF, 2012), reflects the upper bound of this range, so $a_{Dn} + 2\, b_{Dn}\, \overline{K}_{Dn} \approx 52.81$.

Finally, we assume there are no social losses from externalities due to (solar) distributed generation of electricity. The corresponding losses are assumed to increase linearly with electricity produced by the VIP.[51] Specifically, we assume $L(Q^v, Q^D) = e_v\, Q^v$, where $e_v = \phi_c\, e_c + \phi_g\, e_g + \phi_o\, e_o$. ϕ_c, ϕ_g, and ϕ_o denote the fraction of the VIP's electricity production that is generated by coal, natural gas, and other units, respectively.[52] We initially set $e_c = 37.231$, $e_g = 21.029$, and $e_o = 0$. e_j is the estimated unit loss from environmental externalities for technology $j \in \{c, g, o\}$. This estimate is the product of \$38, the estimated social cost of a metric ton of CO_2 emissions (EPA, 2013), and the metric tons of CO_2

[50] Recall that $\overline{Q}^v = 24,577$ is the average MWh's of electricity sold daily by California utilities in 2014 and $\overline{K}_G = 72,926$ is the MW of centralized non-renewable generation capacity in California at year-end 2014. Thus, the initial value for c_v (and hence a_v) reflects the assumption that the welfare-maximizing level of capacity in the model is $\overline{K}_G$.

[51] For simplicity, we abstract from the non-linearities that arise in practice as different technologies are employed to meet baseload, systematic non-baseload, and peak-load demand for electricity.

[52] In practice, other units primarily reflect hydro and nuclear production. $\phi_o = 1 - \phi_c - \phi_g$.

emissions that arise when technology j is employed to produce a MWh of electricity.[53] In the current baseline setting, we assume $\phi_c = 0.064$ and $\phi_g = 0.445$, reflecting the fraction of electricity generated by California utilities in 2014 using coal and natural gas generating units, respectively (California Energy Commission, 2015). Consequently, $e_v = 11.746$.

Table 1 characterizes the optimal regulatory policy and industry outcomes in the baseline setting both when the regulator can set DG capacity charges (column 3) and when she cannot do so (column 2).[54] π_{Dy} in Table 1 denotes the expected profit from DG employing technology $y \in \{i, n\}$, where i denotes "intermittent" and n denotes "non-intermittent."[55] $E\{S\}$ denotes the expected social losses due to environmental externalities. Because consumer D cannot control the level of DG output from the intermittent technology other than through his choice of capacity (K_{Di}), w_i and k_i are redundant instruments for the regulator when both are available. In this event, we assume the regulator implements net metering ($w_i = r$) for the intermittent DG ("DG-i") technology.

Four elements of Table 1 warrant emphasis. First, when DG capacity charges are feasible, the regulator optimally imposes a capacity tax ($k_i < 0$) on the DG-i technology. The tax reduces investment in the technology below the (socially excessive) level that net metering would induce in the absence of a tax. When DG capacity charges are not feasible, the unit payment for DG-i output (w_i) is reduced substantially below the unit retail price of electricity (r) in order to limit excessive investment in DG-i capacity.

Second, the regulator also imposes a capacity tax on the non-intermittent DG ("DG-n") technology when capacity charges are feasible. Doing so limits excessive investment in DG-n capacity that otherwise arises when w_n is set both to induce an efficient level of

[53] EIA (2014a) estimates that 2.16 (1.22) pounds of carbon dioxide are emitted when a KWh of electricity is produced using a coal (natural gas) generating unit. These estimates are multiplied by $1,000$ to convert KWhs to MWhs, and divided by $2,204.62$ to convert pounds to metric tons. Thus, $e_c = 38\,[\,2.16\,]\,\frac{1,000}{2,204.62} = 37.231$ and $e_g = 38\,[\,1.22\,]\,\frac{1,000}{2,204.62} = 21.029$.

[54] Brown and Sappington (2016) review the methodology employed to derive the findings in Table 1.

[55] Profit is the difference between: (i) the sum of payments for DG output and any relevant payments for installing DG capacity; and (ii) the sum of DG capacity costs and any relevant variable costs of DG production.

DG-n output and motivate investment in DG-n capacity. The reduction in DG-n capacity investment that is optimally induced when DG capacity charges are feasible is offset in part by increased centralized generating capacity (K_G).

Third, the significant (12.73%) decline in DG-n capacity when capacity charges are feasible results in a substantial (23.83%) decline in profit from DG-n operations, which reduces the expected utility of consumer D.[56] Fourth, because electricity production is shifted from the relatively "dirty" DG-n technology to the relatively "clean" centralized production technology, the expected social losses from environmental externalities decline when capacity charges are feasible.

Outcomes in the baseline setting are sensitive to the presumed impact of DG on the utility's T&D costs. Distinct outcomes can arise if DG reduces, rather than increases, these costs. To illustrate this conclusion, suppose all parameters are as specified in the baseline setting except α_T^{Dn} is reduced to -11.0, so investment in the DG-n technology reduces the utility's T&D costs substantially.[57] As Table 2 reports, the regulator now implements a capacity payment ($k_n > 0$) rather than a capacity tax for the DG-n technology when capacity charges are feasible. Perhaps more surprisingly, the regulator also increases the unit payment for DG output (w_n). The capacity payment induces a substantial increase in DG-n capacity, and a corresponding reduction in centralized capacity (K_G) is implemented. The reduction in K_G increases the VIP's marginal cost of producing electricity. In light of this higher marginal cost, w_n is increased to induce more output from the DG-n technology, which admits a reduction in (now relatively costly) output by the VIP.[58]

[56] Consumer N's expected utility increases because the unit retail price of electricity declines when the regulator can employ capacity charges to reduce industry production costs. Aggregate expected wefare is little changed, in part because consumer surplus substantially exceeds industry costs under the presumed demand and cost structures.

[57] Cohen et al. (2015) report widely varying estimates of the impact of DG on utility T&D costs. Clean Power Research (2014) estimates that these costs decline by \$11.00 for each MWh of PV capacity investment.

[58] If $\alpha_T^{Di} = \alpha_T^{Dn} = -11.0$, then when capacity charges become feasible, the regulator reduces w_n as she implements a capacity payment, $k_n > 0$. This is the case because the reduction in the VIP's capacity is less pronounced in this setting than in the setting of Table 2, so the corresponding increase in the VIP's marginal cost of producing electricity is less pronounced.

The increased investment in DG-n capacity in this setting when capacity charges are feasible leads to a pronounced (106.73%) increase in the profit from DG-n operations. The expected social losses from externalities increase as output is shifted from the VIP's relatively clean technology to the DG-n technology.

To illustrate the different qualitative conclusions that can arise under other circumstances, now consider a "coal-intensive" setting where the VIP primarily employs coal-powered generating units to serve a relatively small market. Specifically, suppose $\phi_c = 0.9$, $\phi_g = 0.1$, and the demand parameters (m_j) are chosen to ensure $E\{ m_j \left[1 + \theta^{\beta_j} \right] \widetilde{r}^{\alpha_j} \} = \eta_j \widehat{X}$, where $\widehat{X} = 21,404$.[59] Further suppose the VIP's capacity parameters ($a_K = 16.1$, $b_K = 0.000674$) ensure that the marginal cost of capacity required to generate a MWh of electricity is approximately 60.4 when $K_G = \widehat{K}_G = 32,854$.[60,61]

Table 3 reports that when capacity charges become feasible in the coal intensive setting, the regulator optimally implements a capacity payment ($k_i > 0$) for the clean DG-i technology and a capacity tax ($k_n < 0$) for the less clean DG-n technology. This payment and tax induce increased investment in DG-i capacity and reduced investment in DG-n capacity. On balance, profit from DG operations declines and social losses from externalities increase slightly.

Tables 1 – 3 illustrate that the ability to set capacity charges can induce significant changes in industry outcomes and that the nature and extent of the changes can vary substantially across settings. Brown and Sappington (2016) show that significant and varied changes persist in other plausible settings of interest.

[59] The smaller level of expected demand ($\widehat{X} < \overline{X}$) reflects the average daily consumption of electricity in Ohio in 2014 (EIA, 2015c). $e_v = 35.692$ when $\phi_c = 0.9$ and $\phi_g = 0.1$.

[60] $\widehat{K}_G = 32,854$ MW reflects the level of centralized non-renewable generation capacity in Ohio in 2013 (EIA, 2015c). The estimated cost of capacity required to produce a MWh of electricity using a coal generating unit is \$60.4 (EIA, 2015a).

[61] Much as in the baseline setting, we choose a_v, b_v, and c_v to reflect Bushnell (2007)'s estimates for the serving region of the PJM regional transmission organization (i.e., $a = 0$ and $b = 0.0009$), assuming that the welfare-maximizing level of VIP capacity in the model is $\widehat{K}_G$. The values of a_n and b_n are set as in the baseline setting, except that the benchmark level of DG-n capacity is reduced to $\widehat{K}_{Dn} = 3,837.35 = 0.1168 \cdot \widehat{K}_G$, reflecting the same ratio of DG-n to VIP capacity ($\overline{K}_{Dn}/\overline{K}_G = 0.1168$) as in the baseline setting.

8 Conclusions

We have examined the optimal design of policies to promote efficient distributed generation (DG) of electricity. Our analysis produced the following seven conclusions that may help to inform the current debate about desirable DG policies.

First, there is no single policy that best promotes efficient DG in all settings. The optimal policy varies with the characteristics of the prevailing environment, including the set of policy instruments available to the regulator and the relevant DG production technologies.

Second, DG capacity charges enhance consumer welfare in the presence of non-intermittent DG production technologies. The capacity charges can be employed to induce efficient investment in DG capacity while payments for electricity produced with the non-intermittent DG technology can be employed to induce efficient production levels.

Third, in the absence of social losses from externalities, retail prices and DG payments for electricity that reflect the VIP's marginal cost of generating electricity induce both the efficient consumption of electricity and the efficient allocation of electricity production among industry suppliers. Therefore, common net metering policies (whereby the unit payment for distributed production of electricity is set equal to the prevailing retail price of electricity) can be part of an optimal policy. This is the case as long as DG capacity charges are set to reflect the impact of increased DG capacity on the VIP's transmission and distribution costs.

Fourth, when state-specific (e.g., real time) prices and DG payments are not feasible but DG capacity charges are feasible, the optimal unit DG payment for electricity reflects the VIP's expected marginal cost of generating electricity. In contrast, the optimal unit retail price of electricity is set so that a weighted average of deviations between price and the VIP's marginal cost of generating electricity is zero. Consequently, net metering typically is not optimal for non-intermittent DG technologies. Net metering can be optimal for intermittent DG technologies because DG payments do not affect the amount of electricity produced with the installed capacity of such technologies. Therefore, DG capacity charges can be set to induce efficient intermittent capacity investment, given unit DG payments that reflect prevailing retail prices of electricity.

Fifth, net metering typically is not optimal even for intermittent DG technologies when the regulator is unable to set DG capacity charges. In this case, unit DG payments for electricity must be designed to induce efficient DG capacity investment whereas retail prices optimally are designed to induce efficient electricity consumption.

Sixth, fixed retail charges for electricity can play an important role in inducing efficient electricity consumption, particularly when they do not affect the demand for electricity. Such fixed charges enable the regulator to set unit retail electricity prices to reflect the VIP's marginal cost of production while ensuring a normal expected profit for the VIP.[62]

Seventh, the presence of social losses from externalities affects optimal retail prices and DG payments in intuitive ways. In particular, retail prices of electricity are increased above the VIP's marginal cost of generating electricity to reflect the marginal social loss from externalities associated with the VIP's electricity generation. In addition, the unit DG payment for electricity is increased above the VIP's marginal cost of generating electricity to the extent that losses from externalities decline as production is shifted from the VIP to distributed generators. These changes imply that common net metering policies typically are not optimal unless distributed generation of electricity entails no social losses from externalities.

In closing, we note that although we have considered a fairly broad set of policy instruments for the regulator, an even more comprehensive set of instruments warrants formal investigation. Additional instruments of potential interest include demand charges (e.g., Hledik, 2014; Faruqui and Hledik, 2015) and policies that promote demand response (e.g., Chao, 2011; Brown and Sappington, 2015b) and energy conservation (e.g., Brennan, 2010b; Chu and Sappington, 2013). Future research also might consider the changes that arise in the presence of limited consumer information and differential concerns about the welfare of different consumers (e.g., residential vs. industrial consumers or residential consumers who

[62] Fixed DG capacity charges (k_{0i} and k_{0n}) also can serve this function if they do not induce consumers to forego efficient DG capacity investment.

can invest in DG technologies vs. those who cannot).[63]

Variable	No DG Charges	DG Charges	Change	% Change
r	271.23	271.03	-0.20	-0.07
w_i	186.04	271.03	84.99	45.68
w_n	155.36	157.48	2.12	1.36
k_i	0	-20.64	N/A	N/A
k_n	0	-3.19	N/A	N/A
K_{Di}	$4,742.54$	$4,744.53$	1.99	0.04
K_{Dn}	$4,777.62$	$4,169.66$	-607.96	-12.73
K_G	$63,838.65$	$64,378.74$	540.09	0.85
π_{Di}	$20,755.65$	$20,773.10$	17.45	0.08
π_{Dn}	$30,441.31$	$23,186.81$	$-7,254.50$	-23.83
$E\{U^D\}$	$507,287.91$	$500,475.09$	$-6,812.81$	-1.34
$E\{U^N\}$	$4,104,818.49$	$4,108,636.58$	$3,818.09$	0.09
$E\{S\}$	$273,488.68$	$269,849.18$	$-3,639.50$	-1.33

Table 1. Outcomes in the Baseline Setting.

[63]It can be shown that the key qualitative conclusions drawn above continue to hold when the regulator seeks to maximize a weighted average of the welfare of consumer D and the welfare of consumer N, while ensuring a reservation level of expected welfare for both cosumers. In this setting, fixed retail charges are set to deliver a higher level of welfare to the favored consumer while ensuring the less-favored consumer secures his reservation welfare level. Binding limits on feasible fixed retail charges would introduce additional changes to the optimal unit retail prices of electricity.

Variable	No DG Charges	DG Charges	Change	% Change
r	268.07	270.69	2.62	0.98
w_i	187.51	270.69	83.17	44.36
w_n	164.72	166.41	1.69	1.02
k_i	0	-19.23	N/A	N/A
k_n	0	7.42	N/A	N/A
K_{Di}	$4,936.16$	$5,179.84$	243.68	4.94
K_{Dn}	$7,453.82$	$10,071.28$	$2,617.46$	35.12
K_G	$60,472.43$	$57,254.87$	$-3,217.55$	-5.32
π_{Di}	$22,485.03$	$27,432.55$	$4,947.52$	22.00
π_{Dn}	$74,096.70$	$153,183.58$	$79,068.88$	106.73
$E\{U^D\}$	$559,526.75$	$637,876.55$	$78,349.80$	14.00
$E\{U^N\}$	$4,166,505.22$	$4,115,343.82$	$-51,161.40$	-1.23
$E\{S\}$	$295,705.45$	$313,969.18$	$18,262.73$	6.18

Table 2. Outcomes in the Baseline Setting, Except $\alpha_T^{Dn} = -11.0$.

Variable	No DG Charges	DG Charges	Change	% Change
r	196.85	196.73	-0.11	-0.06
w_i	223.80	196.73	-27.07	-12.10
w_n	184.40	185.16	0.76	0.41
k_i	0	6.62	N/A	N/A
k_n	0	-1.07	N/A	N/A
K_{Di}	$9,711.10$	$9,734.95$	23.85	0.25
K_{Dn}	$6,170.57$	$6,107.17$	-63.40	-1.03
K_G	$27,350.57$	$27,374.23$	23.66	0.09
π_{Di}	$87,026.54$	$87,454.55$	428.00	0.49
π_{Dn}	$112,719.09$	$110,414.88$	$-2,304.20$	-2.04
$E\{U^D\}$	$725,364.95$	$723,712.61$	$-1,652.34$	-0.23
$E\{U^N\}$	$4,730,573.92$	$4,732,588.64$	$2,014.72$	0.04
$E\{S\}$	$539,439.40$	$539,776.65$	337.25	0.06

Table 3. Outcomes in the Coal Intensive Setting.

Appendix

Part A of this Appendix states and proves Proposition 6 and compares the findings in Propositions 3 and 6. Part B of this Appendix provides proofs of the propositions in the text.

A. TOU Prices and TOP DG Payments with Externalities.

Let [RP-te] denote the regulator's problem in the setting where the regulator sets TOU retail prices and TOP DG payments (and DG capacity charges) and where social losses from externalities ($S_t(Q_t^v,\, Q_t^i,\, Q_t^n)$) are present. This problem is [RP-θe] with the additional restrictions specified in condition (8).

Proposition 6. *At the solution to [RP-te], conclusion (i) in Proposition 3 holds. In addition, for* $t, t' \in \{L, H\}$ $(t' \neq t)$*:*

$$\text{(i)} \quad \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[r_{jt} - \left(\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} + S_{tv}(\cdot) \right) \right] \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}}\, dF_t(\theta_s)$$

$$+ \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'} - \left(\frac{\partial C_{t'}^G(Q_{t'}^v(\cdot,\theta_{s'}), K_G)}{\partial Q_{t'}^v(\cdot,\theta_{s'})} + S_{t'v}(\cdot) \right) \right] \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}}\, dF_{t'}(\theta_{s'}) \;=\; 0\,;$$

$$\text{(ii)} \quad w_{nt} \;=\; \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} + S_{tv}(\cdot) - S_{tn}(\cdot) \right] dF_t(\theta_s); \;\; \textit{and}$$

$$\text{(iii)} \quad k_y \;=\; \sum_{t\,\in\,\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{\partial C_t^G(\cdot)}{\partial Q_t^v(\cdot,\theta_s)} - w_{yt} + S_{tv}(\cdot) - S_{ty}(\cdot) \right] \frac{\partial Q_t^y(\cdot,\theta_s)}{\partial K_{Dy}}\, dF_t(\theta_s) - \frac{\partial T(\cdot)}{\partial K_{Dy}}$$

for $y \in \{i, n\}$.

Proof. Let $\lambda \geq 0$ denote the Lagrange multiplier associated with constraint (5). Then (1), (2), (3), (8), and the Envelope Theorem imply that that a solution to [RP-te], for $y \in \{i, n\}$, $j \in \{N, D\}$, and $t,\, t' \in \{L, H\}$ ($t' \neq t$):

$$K_G: \quad \lambda \left[\sum_{t\,\in\,\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(- \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v} \frac{dQ_t^v(\cdot)}{dK_G} - \frac{\partial C_t^G(\cdot)}{\partial K_G} \right) dF_t(\theta_s) \right.$$

$$\left. -\; C^{K\prime}(K_G) - \frac{\partial T(\cdot)}{\partial K_G} \right] - \sum_{t\,\in\,\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} S_{tv}(\cdot)\, \frac{dQ_t^v(\cdot,\theta_s)}{dK_G}\, dF_t(\theta_s) \;=\; 0\,; \tag{9}$$

$$k_y: \quad K_{Dy} - \sum_{t\,\in\,\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(S_{ty}(\cdot)\, \frac{\partial Q_t^y(\cdot,\theta_s)}{\partial K_{Dy}}\, \frac{\partial K_{Dy}}{\partial k_y} + S_{tv}(\cdot)\, \frac{dQ_t^v(\cdot,\theta_s)}{dk_y} \right) dF_t(\theta_s)$$

$$- \;\lambda \Bigg[\sum_{t \in \{\, L,H \,\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_{yt} \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{dQ_t^v(\cdot)}{dk_y} \right) dF_t(\theta_s)$$

$$+ \;\; K_{Dy} + k_y \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} \Bigg] \;=\; 0\,; \tag{10}$$

$$w_{yt}: \quad \int_{\underline{\theta}_t}^{\overline{\theta}_t} Q_t^y(\cdot,\theta_s)\, dF_t(\theta_s) - \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(S_{ty}(\cdot) + S_{tv}(\cdot) \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial Q_t^y} \right) \frac{\partial Q_t^y(\cdot,\theta_s)}{\partial w_{yt}} dF_t(\theta_s)$$

$$- \sum_{t' \in \{\, L,H \,\}} \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left(S_{t'y}(\cdot) + S_{t'v}(\cdot) \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial Q_{t'}^y} \right) \frac{\partial Q_{t'}^y(\cdot,\theta_{s'})}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}} dF_{t'}(\theta_{s'})$$

$$- \lambda \Bigg[\sum_{t' \in \{\, L,H \,\}} \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left(w_{yt'} \frac{\partial Q_{t'}^y(\cdot,\theta_{s'})}{\partial K_{Dy}} + \frac{\partial C_{t'}^G(\cdot)}{\partial Q_{t'}^v} \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial Q_{t'}^y} \frac{\partial Q_{t'}^y(\cdot)}{\partial K_{Dy}} \right) \frac{\partial K_{Dy}}{\partial w_{yt}} dF_{t'}(\theta_{s'})$$

$$+ \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(Q_t^y(\cdot,\theta_s) + w_{yt} \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}} \right) dF_t(\theta_s)$$

$$+ \;\; k_y \frac{\partial K_{Dy}}{\partial w_{yt}} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}} \Bigg] \;=\; 0\,; \tag{11}$$

$$R_j: \quad -\,1 + \lambda \;=\; 0\,; \tag{12}$$

$$r_{jt}: \quad \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(\left[\frac{\partial V_t^j(X_t^j(\cdot,\theta_s),\theta_s)}{\partial X_t^j} - r_{jt} \right] \frac{\partial X_t^j(\cdot)}{\partial r_{jt}} - X_t^j(\cdot) \right) dF_t(\theta_s)$$

$$+ \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left(\frac{\partial V_{t'}^j(X_{t'}^j(\cdot,\theta_{s'}),\theta_{s'})}{\partial X_{t'}^j} - r_{jt'} \right) \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}} \, dF_{t'}(\theta_{s'})$$

$$- \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(S_{tv}(\cdot) \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial X_t} \frac{\partial X_t(\cdot,\theta_s)}{\partial X_t^j} \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}} \right) dF_t(\theta_s)$$

$$- \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left(S_{t'v}(\cdot) \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial X_{t'}} \frac{\partial X_{t'}(\cdot,\theta_{s'})}{\partial X_{t'}^j} \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}} \right) dF_{t'}(\theta_{s'})$$

$$+ \;\lambda \Bigg[\int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(r_{jt} \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}} + X_t^j(\cdot) \right) dF_t(\theta_s) + \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} r_{jt'} \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}} \, dF_{t'}(\theta_{s'})$$

$$- \int_{\underline{\theta}_t}^{\overline{\theta}_t} \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial X_t^j} \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}} \, dF_t(\theta_s)$$

$$- \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \frac{\partial C_{t'}^G(Q_{t'}^v(\cdot,\theta_{s'}), K_G)}{\partial Q_{t'}^v} \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial X_{t'}^j} \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}} \, dF_{t'}(\theta_{s'}) \Bigg] \; = \; 0 \, . \qquad (13)$$

(12) implies that $\lambda = 1$. $\frac{\partial V_t^j(X_t^j(\cdot,\theta_s),\theta_s)}{\partial X_t^j} = r_{jt}$ for $j \in \{D, N\}$ and $t \in \{L, H\}$ since $V_t^j(x, \theta_s)$ is the gross surplus consumer j derives from output x in state θ_s in period t. Also, $\frac{\partial X_t}{\partial X_t^j} = \frac{\partial Q_t^v}{\partial X_t^j} = \frac{\partial Q_t^v}{\partial X_t} = 1$ because $Q_t^v = X_t^N + X_t^D - Q_t^i - Q_t^n$ and $X_t = X_t^N + X_t^D$. Therefore, (13) implies that conclusion (i) in the proposition holds.

Since $\lambda = 1$ and $\frac{dQ_t^v}{dK_G} = 0$, (9) implies that conclusion (i) in Proposition 3 holds.

Observe that $\lambda = 1$, $\frac{dQ_t^v(\cdot,\theta_s)}{dK_{Di}} = -\mu_t \theta_s$, $\frac{\partial K_{Di}}{\partial k_i}$ is not a function of θ_s, and k_i only affects Q_t^v through K_{Di}. Therefore, for $y = i$, (10) can be written as conclusion (iii) in the proposition. The proof of conclusion (iii) for $y = n$ is analogous.

Observe that $\lambda = 1$, $\frac{\partial K_{Dn}}{\partial w_{nt}}$ is not a function of $\theta_{t'}$ for any $t' \in \{L, H\}$, and $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$. Therefore, for $y = n$, (11) can be written as:

$$- \Bigg[\sum_{t' \in \{L,H\}} \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left(w_{nt'} - \frac{\partial C_{t'}^G(\cdot)}{\partial Q_{t'}^v} + S_{t'n}(\cdot) - S_{t'v}(\cdot) \right) \frac{\partial Q_{t'}^n(\cdot,\theta_{s'})}{\partial K_{Dn}} \, dF_{t'}(\theta_{s'}) + k_n$$

$$+ \frac{\partial T(\cdot)}{\partial K_{Dn}} \Bigg] \frac{\partial K_{Dn}}{\partial w_{nt}} - \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_{nt} - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right) \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial w_{nt}} \, dF_t(\theta_s) \; = \; 0$$

$$\Rightarrow \quad \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[w_{nt} - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right] \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial w_{nt}} \, dF_t(\theta_s) \; = \; 0 \, . \qquad (14)$$

(14) reflects conclusion (iii) in the proposition for $y = n$. Since $\frac{\partial Q_t^n(\cdot,\theta_s)}{\partial w_{nt}}$ is not a function of θ_s, (14) implies that conclusion (ii) in the proposition holds. ■

A comparison of Propositions 3 and 6 reveals that the presence of social losses from externalities affects the optimal regulatory policy under TOU retail pricing and TOP DG compensation much as they do under state-specific retail pricing and DG compensation. In particular, retail prices are increased to discourage the purchase of electricity from the VIP as the social losses from externalities associated with electricity production by the VIP increase. In addition, DG payments for electricity produced using the non-intermittent technology increase as marginal social losses from externalities associated with this production decline relative to the marginal social losses associated with electricity production by the VIP, *ceteris paribus*. Furthermore, DG capacity charges are reduced as marginal losses from externalities associated with DG production decline relative to the corresponding losses associated with electricity production by the VIP.

B. Proofs of the Propositions in the Text.

Proof of Proposition 1. The proof follows immediately from the proof of Proposition 2. ■

Proof of Proposition 2.

Let $\lambda \geq 0$ denote the Lagrange multiplier associated with constraint (5). Then (1), (2), (3), and the Envelope Theorem imply that at a solution to [RP-θe], for $y \in \{i, n\}$ and $j \in \{N, D\}$:

$$k_y: \quad K_{Dy} - \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(S_{ty}(\cdot) \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} + S_{tv}(\cdot) \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} \right) dF_t(\theta_s)$$

$$- \lambda \Bigg[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_{yt}(\theta_s) \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{dQ_t^v(\cdot, \theta_s)}{dk_y} \right) dF_t(\theta_s)$$

$$+ K_{Dy} + k_y \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial k_y} \Bigg] = 0\,; \qquad (15)$$

$$w_{yt}(\theta_s): \quad Q_t^y(\cdot, \theta_s)\, f_t(\theta_s) - \Bigg[S_{ty}(\cdot) \left(\frac{\partial Q_t^y(\cdot, \theta_s)}{\partial w_{yt}(\theta_s)} + \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} \right)$$

$$+ \; S_{tv}(\cdot) \left(\frac{\partial Q_t^v(\cdot)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}(\theta_s)} + \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} \right) \Bigg] f_t(\theta_s)$$

$$- \; \lambda \Bigg[\Bigg(w_{yt}(\theta_s) \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)}$$

$$+ \; Q_t^y(\cdot, \theta_s) + w_{yt}(\theta_s) \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial w_{yt}(\theta_s)} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}(\theta_s)} \Bigg) f_t(\theta_s)$$

$$+ \; k_y \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} \Bigg] = 0\,; \qquad (16)$$

$$
\begin{aligned}
r_{jt}(\theta_s): \quad & \left[\left(\frac{\partial V_t^j(X_t^j(\cdot,\theta_s),\theta_s)}{\partial X_t^j(\cdot,\theta_s)} - r_{jt}(\theta_s) \right) \frac{\partial X_t^j(\cdot)}{r_{jt}(\theta_s)} - X_t^j(\cdot) \right] f_t(\theta_s) \\
+ & \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[\frac{\partial V_{t'}^j(X_{t'}^j(\cdot,\theta_{s'}),\theta_{s'})}{\partial X_{t'}^j(\cdot,\theta_{s'})} - r_{jt'}(\theta_{s'}) \right] \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} \, dF_{t'}(\theta_{s'}) \\
- & \left[S_{tv}(\cdot) \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial X_t^j} \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}(\theta_s)} f_t(\theta_s) + \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} S_{t'v}(\cdot) \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial X_{t'}^j} \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} \, dF_{t'}(\theta_{s'}) \right] \\
+ & \lambda \left[r_{jt}(\theta_s) \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}(\theta_s)} + X_t^j(\cdot,\theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot,\theta_s)}{\partial X_t^j(\cdot,\theta_s)} \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}(\theta_s)} \right] f_t(\theta_s) \\
+ & \lambda \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'}(\theta_{s'}) \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} - \frac{\partial C_{t'}^G(\cdot)}{\partial Q_{t'}^v(\cdot,\theta_{s'})} \frac{\partial Q_{t'}^v(\cdot,\theta_{s'})}{\partial X_{t'}^j(\cdot,\theta_{s'})} \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} \right] dF_{t'}(\theta_{s'}) \; = \; 0 \, . \quad (17)
\end{aligned}
$$

(9) and (12) also hold. Therefore, $\lambda = 1$ and conclusion (i) in Proposition 1 holds. Also, $\frac{\partial Q_t^v}{\partial X_t^j} = 1$ and $\frac{\partial V_t^j(X_t^j(\cdot,\theta_t),\theta_s)}{\partial X_t^j} = r_{jt}(\theta_s)$ for $j \in \{D, N\}$. Therefore, from (17), for each $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$:

$$
\begin{aligned}
& \left[r_{jt}(\theta_s) - \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)} - S_{tv}(\cdot) \right] \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}(\theta_s)} \; f_t(\theta_s) \\
& \quad + \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'}(\theta_{s'}) - \frac{\partial C_{t'}^G(Q_{t'}^v(\cdot,\theta_{s'}),K_G)}{\partial Q_{t'}^v(\cdot,\theta_{s'})} - S_{t'v}(\cdot) \right] \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} \, dF_{t'}(\theta_{s'}) \; = \; 0 \, . \quad (18)
\end{aligned}
$$

(18) is satisfied if:

$$
r_{jt}(\theta_s) \; = \; \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v(\cdot,\theta_s)} + S_{tv}(\cdot) \;\; \text{for all } \; \theta_s \in [\underline{\theta}_t, \overline{\theta}_t] \, . \quad (19)
$$

Observe that $\lambda = 1$, $\frac{\partial K_{Di}}{\partial k_{it}}$ is not a function of θ_s, and k_i only affects Q_t^v through K_{Di}. Therefore, for $y = i$, (15) can be written as:

$$
\begin{aligned}
& \Bigg[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_{it}(\theta_s) \, \mu_t \, \theta_s + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{dQ_t^v(\cdot,\theta_s)}{dK_{Di}} + S_{ti}(\cdot) \frac{\partial Q_t^i(\cdot,\theta_s)}{\partial K_{Di}} + S_{tv}(\cdot) \frac{dQ_t^v(\cdot)}{dK_{Di}} \right) dF_t(\theta_s) \\
& \qquad\qquad + \; k_i + \frac{\partial T(\cdot)}{\partial K_{Di}} \Bigg] \frac{\partial K_{Di}}{\partial k_i} \; = \; 0 \, . \quad (20)
\end{aligned}
$$

Since $\frac{dQ_t^v(\cdot,\theta_s)}{dK_{Di}} = -\mu_t\,\theta_s$ and $\frac{\partial Q_t^i(\cdot,\theta_s)}{\partial K_{Di}} = \mu_t\,\theta_s$, (20) can be written as:

$$k_i \;=\; -\frac{\partial T(\cdot)}{\partial K_{Di}} + \sum_{t\in\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v} - w_{it}(\theta_s) + S_{tv}(\cdot) \right. \\ \left. -\; S_{ti}(\cdot) \right] \mu_t\,\theta_s\, dF_t(\theta_s)\,. \tag{21}$$

Observe that $\lambda = 1$, $\frac{\partial K_{Dn}}{\partial k_{nt}}$ is not a function of θ_s, and k_{nt} only affects Q_t^v through K_{Dn} and the corresponding impact on Q_t^n. Therefore, for $y = n$, (15) can be written as:

$$-\left[\sum_{t\in\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_{nt}(\theta_s) + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v}\frac{\partial Q_t^v(\cdot,\theta_s)}{\partial Q_t^n} + S_{tn}(\cdot) + S_{tv}(\cdot)\frac{\partial Q_t^v(\cdot)}{\partial Q_t^n} \right) \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial K_{Dn}}\, dF_t(\theta_s) \right. \\ \left. +\; k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} \right] \frac{\partial K_{Dn}}{\partial k_n} \;=\; 0\,. \tag{22}$$

Since $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$, (22) can be written as:

$$k_n \;=\; -\frac{\partial T(\cdot)}{\partial K_{Dn}} + \sum_{t\in\{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v} - w_{nt}(\theta_s) + S_{tv}(\cdot) - S_{tn}(\cdot) \right] \\ \cdot\; \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial K_{Dn}}\, dF_t(\theta_s)\,. \tag{23}$$

Observe that $\lambda = 1$, $\frac{\partial Q_t^i(\cdot,\theta_s)}{\partial K_{Di}} = \mu_t\,\theta_s$, $\frac{\partial Q_t^i(\cdot,\theta_s)}{\partial w_{it}(\theta_s)} = 0$, and $\frac{\partial Q_t^v(\cdot,\theta_s)}{\partial K_{Di}} = -\mu_t\,\theta_s$. Therefore, for $y = i$, (16) can be written as:

$$\left[\left(w_{it}(\theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{ti}(\cdot) - S_{tv}(\cdot) \right) \mu_t\,\theta_s\, f_t(\theta_s) + k_i + \frac{\partial T(\cdot)}{\partial K_{Di}} \right] \frac{\partial K_{Di}}{\partial w_{it}(\theta_s)} \;=\; 0\,.$$

Therefore, for all $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$:

$$k_i \;=\; -\frac{\partial T(\cdot)}{\partial K_{Di}} + \left[\frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v} - w_{it}(\theta_s) + S_{tv}(\cdot) - S_{ti}(\cdot) \right] \mu_t\,\theta_s\, f_t(\theta_s)\,. \tag{24}$$

Observe that (21) and (24) are satisfied if:

$$w_{it}(\theta_s) \;=\; \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s),K_G)}{\partial Q_t^v} + S_{tv}(\cdot) - S_{ti}(\cdot) \;\text{ for all }\; \theta_s \in [\underline{\theta}_t, \overline{\theta}_t]\,. \tag{25}$$

(24) implies that if (25) holds, then:

$$k_i \;=\; -\frac{\partial T(\cdot)}{\partial K_{Di}}\,. \tag{26}$$

Recall that $\lambda = 1$ and $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$. Therefore, for $y = n$, (16) can be written as:

$$\left[w_{nt}(\theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right] \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial K_{Dn}} \frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)} f_t(\theta_s)$$

$$+ \left[w_{nt}(\theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right] \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial w_{nt}(\theta_s)} f_t(\theta_s)$$

$$+ \ k_n \frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)} + \frac{\partial T(\cdot)}{\partial K_{Dn}} \frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)} = 0 .$$

Therefore, for each $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$:

$$\left[\left(w_{nt}(\theta_s) - \frac{\partial C^G(\cdot)}{\partial Q^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right) \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial K_{Dn}} f_t(\theta_s) + k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} \right] \frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)}$$

$$+ \left[w_{nt}(\theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot) \right] \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial w_n(\theta_s)} f_t(\theta_s) = 0 . \tag{27}$$

Since $\frac{\partial Q_t^n(\cdot, \theta_s)}{\partial K_{Dn}} > 0$, $\frac{\partial Q_t^n(\cdot, \theta_s)}{\partial w_n(\theta_s)} > 0$, and $\frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)} > 0$ for all $\theta_s \in [\underline{\theta}_t, \overline{\theta}_t]$, (27) implies that if $w_{nt}(\theta_s) > \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot)$, then $k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} < 0$. (27) also implies that if $w_{nt}(\theta_s) < \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} + S_{tn}(\cdot) - S_{tv}(\cdot)$, then $k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} > 0$. Therefore, because $k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}}$ does not vary with θ_s, it must be the case that:

$$w_{nt}(\theta_s) = \frac{\partial C_t^G(Q_t^v(\cdot, \theta_s), K_G)}{\partial Q_t^v} + S_{tv}(\cdot) - S_{tn}(\cdot) \ \text{ for all } \theta_s \in [\underline{\theta}_t, \overline{\theta}_t] . \tag{28}$$

(23) and (28) imply:

$$k_n = - \frac{\partial T(\cdot)}{\partial K_{Dn}} . \quad \blacksquare \tag{29}$$

Proof of Proposition 3. The proof follows immediately from the proof of Proposition 6. ■

Proof of Proposition 4.

Let $\lambda \geq 0$ denote the Lagrange multiplier associated with constraint (5). Then (1), (2), (3), and the Envelope Theorem imply that at a solution to [RP], for $y \in \{i, n\}$, $j \in \{N, D\}$, and $t \in \{L, H\}$:

$$K_G : \quad \lambda \left[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(- \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{d Q_t^v(\cdot, \theta_s)}{d K_G} - \frac{\partial C_t^G(\cdot)}{\partial K_G} \right) dF_t(\theta_s) \right.$$

$$- \; C^{K\prime}(K_G) - \frac{\partial T(\cdot)}{\partial K_G} \Bigg] \;=\; 0\,; \tag{30}$$

$$k_y : \quad K_{Dy} - \; \lambda \Bigg[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_y \, \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{d Q_t^v(\cdot, \theta_s)}{d k_y} \right) dF_t(\theta_s)$$

$$+ \;\; K_{Dy} + k_y \, \frac{\partial K_{Dy}}{\partial k_y} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial k_y} \Bigg] \;=\; 0\,; \tag{31}$$

$$w_y : \quad \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} Q_t^y \, dF_t(\theta_s)$$

$$- \;\; \lambda \Bigg[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_y \, \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial w_y} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \, \frac{\partial Q_t^y(\cdot)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial w_y} \right.$$

$$\left. + \;\; Q_t^y \; + w_y \, \frac{\partial Q_t^y}{\partial w_y} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{\partial Q_t^v(\cdot)}{\partial Q_t^y} \, \frac{\partial Q_t^y(\cdot)}{\partial w_y} \right) dF_t(\theta_s)$$

$$+ \;\; k_y \, \frac{\partial K_{Dy}}{\partial w_y} + \frac{\partial T(\cdot)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial w_y} \Bigg] \;=\; 0\,; \tag{32}$$

$$r : \quad \sum_{j \in \{D,N\}} \; \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(\left[\frac{\partial V_t^j(X_t^j(\cdot, \theta_s), \theta_s)}{\partial X_t^j} - r \right] \frac{\partial X_t^j(\cdot)}{\partial r_j} - X_t^j(\cdot) \right) dF_t(\theta_s)$$

$$+ \, \lambda \Bigg[\sum_{j \in \{D,N\}} \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(r \, \frac{\partial X_t^j(\cdot, \theta_s)}{\partial r_j} + X_t^j(\cdot) \right.$$

$$\left. - \;\; \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial X_t^j} \, \frac{\partial X_t^j(\cdot, \theta_s)}{\partial r} \right) dF_t(\theta_s) \Bigg] \;=\; 0\,. \tag{33}$$

(12) also holds, so $\lambda = 1$. Also, $\frac{\partial Q_t^v}{\partial X_t^j} = 1$ and $\frac{\partial V_t^j(X_t^j(r,\theta_s),\theta_s)}{\partial X_t^j} = r$ for $j \in \{D, N\}$ and $t \in \{L, H\}$. Therefore, (33) implies that conclusion (i) of the proposition holds.

Since $\lambda = 1$ and $\frac{dQ_t^v}{dK_G} = 0$, (30) implies that conclusion (i) in Proposition 3 holds.

$\lambda = 1$, $\frac{\partial K_{Dn}}{\partial k_n}$ is not a function of θ_s, and k_n only affects Q_t^v through K_{Dn} and the corresponding impact on Q_t^n. Therefore, for $y = n$, (31) can be written as:

$$- \Bigg[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_n + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^n} \right) \frac{\partial Q_t^n}{\partial K_{Dn}} \, dF_t(\theta_s) + k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} \Bigg] \frac{\partial K_{Dn}}{\partial k_n} \;=\; 0\,.$$

Therefore, since $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$, conclusion (iii) in the proposition holds for $y = n$. The proof of conclusion (iii) for $y = i$ is analogous.

Recall that $\lambda = 1$, $\frac{\partial K_{Dn}}{\partial w_n}$ is not a function of θ_t, and $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$. Therefore, for $y = n$, (32) can be written as:

$$- \left[\sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_n - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \right) \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial K_{Dn}} \, dF_t(\theta_s) + k_n + \frac{\partial T(\cdot)}{\partial K_{Dn}} \right] \frac{\partial K_{Dn}}{\partial w_n}$$

$$- \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left(w_n - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \right) \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial w_n} \, dF_t(\theta_s) = 0$$

$$\Rightarrow \quad \sum_{t \in \{L,H\}} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[w_n - \frac{\partial C_t^G(Q_t^v(\cdot, \theta_s), K_G)}{\partial Q_t^v} \right] \frac{\partial Q_t^n(\cdot, \theta_s)}{\partial w_n} \, dF_t(\theta_s) = 0 \,. \tag{34}$$

(34) reflects conclusion (iii) in the proposition for $y = n$. Since $\frac{\partial Q_t^n}{\partial w_n}$ is not a function of θ_s, (34) implies that conclusion (ii) of the proposition holds. ■

Proof of Proposition 5.

Let $\lambda \geq 0$ denote the Lagrange multiplier associated with constraint (5). Then (1), (2), (3), and the Envelope Theorem imply that at a solution to [RP-θk], for $j \in \{N, D\}$, $t, t' \in \{L, H\}$ $(t' \neq t)$, and $y \in \{i, n\}$:

$$r_{jt}(\theta_s): \quad \left[\left(\frac{\partial V_t^j(X_t^j(\cdot, \theta_s), \theta_s)}{\partial X_t^j(\cdot, \theta_s)} - r_{jt}(\theta_s) \right) \frac{\partial X_t^j}{r_{jt}(\theta_s)} - X_t^j(\cdot) \right] f_t(\theta_s)$$

$$+ \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[\frac{\partial V_{t'}^j(X_{t'}^j(\cdot, \theta_{s'}), \theta_{s'})}{\partial X_{t'}^j(\cdot, \theta_{s'})} - r_{jt'}(\theta_{s'}) \right] \frac{\partial X_{t'}^j(\cdot, \theta_{s'})}{\partial r_{jt}(\theta_s)} \, dF_{t'}(\theta_{s'})$$

$$+ \lambda \left[r_{jt}(\theta_s) \frac{\partial X_t^j(\cdot, \theta_s)}{\partial r_{jt}(\theta_s)} + X_t^j(\cdot, \theta_s) - \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial X_t^j(\cdot, \theta_s)} \frac{\partial X_t^j(\cdot, \theta_s)}{\partial r_{jt}(\theta_s)} \right] f_t(\theta_s)$$

$$+ \lambda \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'}(\theta_{s'}) \frac{\partial X_{t'}^j(\cdot, \theta_{s'})}{\partial r_{jt}(\theta_s)} - \frac{\partial C_{t'}^G(\cdot)}{\partial Q_{t'}^v(\cdot, \theta_{s'})} \frac{\partial Q_{t'}^v(\cdot, \theta_{s'})}{\partial X_{t'}^j(\cdot, \theta_{s'})} \frac{\partial X_{t'}^j(\cdot, \theta_{s'})}{\partial r_{jt}(\theta_s)} \right] dF_{t'}(\theta_{s'}) = 0 \,; \tag{35}$$

$$w_{yt}(\theta_s): \quad Q_t^y(\cdot, \theta_s) \, f_t(\theta_s)$$

$$- \lambda \left[\left(w_{yt}(\theta_s) \frac{\partial Q_t^y(\cdot, \theta_s)}{\partial K_{Dn}} \frac{\partial K_{Dn}}{\partial w_{yt}(\theta_s)} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \frac{\partial Q_t^v(\cdot, \theta_s)}{\partial Q_t^y} \frac{\partial Q_t^y(\cdot)}{\partial K_{Dn}} \frac{\partial K_{Dn}}{\partial w_{yt}(\theta_s)} \right.\right.$$

$$+ \; Q_t^y(\cdot,\theta_s) \; + w_{yt}(\theta_s) \, \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}(\theta_s)} + \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \, \frac{\partial Q_t^v(\cdot)}{\partial Q_t^y} \, \frac{\partial Q_t^y(\cdot)}{\partial w_{yt}(\theta_s)} \Bigg) \, f_t(\theta_s)$$

$$+ \; \frac{\partial T(\cdot)}{\partial K_{Dy}} \, \frac{\partial K_{Dy}}{\partial w_{yt}(\theta_s)} \Bigg] \;=\; 0\,. \tag{36}$$

Since $\lambda = 1$ and $\frac{\partial Q_t^v}{\partial Q_t^n} = -1$, (36) for $y = n$ can be written as:

$$\Bigg[\Bigg(w_{nt}(\theta_s) - \frac{\partial C^G(\cdot)}{\partial Q^v} \Bigg) \frac{\partial Q_t^n(\cdot,\theta_s)}{\partial K_{Dn}} \, f_t(\theta_s) + \frac{\partial T(\cdot)}{\partial K_{Dn}} \Bigg] \frac{\partial K_{Dn}}{\partial w_{nt}(\theta_s)}$$

$$+ \left[w_{nt}(\theta_s) \; - \; \frac{\partial C_t^G(\cdot)}{\partial Q_t^v} \right] \frac{\partial Q_t^n(\cdot)}{\partial w_n(\theta_s)} \, f_t(\theta_s) \;=\; 0 \; \text{ for each } \; \theta_s \in [\,\underline{\theta}_t\,, \overline{\theta}_t\,]\,.$$

Therefore, conclusion (ii) of the proposition for $y = n$ holds for each $\theta_s \in [\underline{\theta}_t\,, \overline{\theta}_t]$. The corresponding proof for $y = i$ is analogous.

$\frac{\partial V_t^j(X_t^j(r,\theta_s),\theta_s)}{\partial X_t^j} = r_{jt}(\theta_s)$ for each $j \in \{D, N\}$ and $t \in \{L, H\}$. Also $\frac{\partial Q_t^v}{\partial X_t^j} = 1$. Therefore, since $\lambda = 1$, (35) implies that for each $\theta_s \in [\,\underline{\theta}_t\,, \overline{\theta}_t\,]$:

$$\left[r_{jt}(\theta_s) - \frac{\partial C_t^G(Q_t^v(\cdot,\theta_s), K_G)}{\partial Q_t^v(\cdot,\theta_s)} \right] \frac{\partial X_t^j(\cdot,\theta_s)}{\partial r_{jt}(\theta_s)} \; f_t(\theta_s)$$

$$+ \int_{\underline{\theta}_{t'}}^{\overline{\theta}_{t'}} \left[r_{jt'}(\theta_{s'}) \; - \; \frac{\partial C_{t'}^G(Q_t^v(\cdot,\theta_{s'}), K_G)}{\partial Q_{t'}^v(\cdot,\theta_{s'})} \right] \frac{\partial X_{t'}^j(\cdot,\theta_{s'})}{\partial r_{jt}(\theta_s)} \, dF_{t'}(\theta_{s'}) \;=\; 0\,. \tag{37}$$

(37) is satisfied if conclusion (i) in the proposition holds. ■

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