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A Study on Reliability Differentiated Pricing of Firm Capacity

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Abstract – It is known that Reliability Differentiated Pricing (RDP) can improve the efficiency and benefits of consumers and producers. This paper examines the long-run social welfare maximization problem of the utility and presents a long-term reliability differentiated prices for firm capacity, based on customer outage costs. Then the applicability of the proposed pricing scheme is verified with a case study.

Keywords: Reliability Differentiated Pricing (RDP), Outage cost, Firm capacity

1. Introduction

Outage Costs represent the economic and non-economic consequences of service curtailments to the customer [1, 2]. Traditionally they are estimated by the customer's willingness-to-pay (WTP) to avoid interruptions in the short-run, assuming that the user does not have sufficient time to change his energy using capital stock [3, 4]. This varies between customers within a class and between classes of customers. The variation will be a function of the degree to which customer applications are dependent upon electricity and to what extent any production or service can be recovered subsequent to an outage.

The earliest studies of the value-based pricing, mostly in the form of priority pricing scheme, stem from the work of Oren, Smith, and Wilson [5-7], and later the theoretical foundation of priority pricing, its efficiency properties and the relations between priority pricing and real-time pricing have been investigated by Chao and Wilson [8-10]. Further studies of the pricing of capacity and usage, and of priority service have been reported in Chao, Oren, Woo, and Wilson [11-14].

Siddiqi and Baughman present a comprehensive theory of reliability differentiated pricing (RDP) that combines elements of both real-time pricing and priority pricing [15-20]. The novelty of this pricing scheme lies in a fact that customer outage cost is adopted as a component of spot prices. At the same time, their theory is predicated on a number of assumptions that seem vulnerable to attack, particularly assumptions on outage cost and consumer behavior.

2. Optimal Long-Term Prices

The long-run problem of a welfare maximizing utility is essentially a resource planning problem using the criterion of maximizing expected consumer's plus producer's surplus subject to operational and resource limits of the system [5-7]. Financial constraints on the utility or any of the participants, which is particularly important for developing countries, will be ignored in the analysis to follow. It is assumed that a single welfare-maximizing public utility owns and operates the transmission network (and possibly the generating plants) of the electric power system under consideration and it sells to independent customers. The utility is assumed to be able to set and communicate prices instantly, and can set a different price for each customer class at each moment. Supply outages are assumed to occur randomly with the probability of an outage possibly being known. Thus customers are aware of an outage only after it has occurred. The utility is assumed to be able to ration supply shortages amongst the various customer classes as it wants to ration it. In the analysis to follow, both generator outages and transmission line outages will be considered.

Consider a utility which solves the following problem of maximizing long-run expected social welfare to determine an optimal resource for given values of customer demands:

$$Max \;\; W = E[\sum_t \{\sum_i F_{it}(P_{it}^d, Q_{it}^d) - \sum_i OC_{it}(P_{it}^u, Q_{it}^u) - \sum_i PC_{it}(P_{it}^g, Q_{it}^g) - \sum_i EC_{it}(P_{it}^s, Q_{it}^s)\}] - \sum_i CC_{it}(K_i^p, K_i^q) \tag{1}$$

subject to the following constraints ;

Load Flow Equations

$$P_{it}^g + P_{it}^s + P_{it}^u - P_{it}^d - \sum_j |V_{it}||V_{jt}||Y_{ij}| Cos(\theta_{ij} + \delta_{jt} - \delta_{it}) = 0 \tag{2-1}$$

$$Q_{it}^g + Q_{it}^s + Q_{it}^u - Q_{it}^d - \sum_j |V_{it}||V_{jt}||Y_{ij}| Sin(\theta_{ij} + \delta_{jt} - \delta_{it}) = 0 \tag{2-2}$$

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Generation Limits

$$0 \le P^{g}_{it} \le K^{p}_{i} a_{it} \tag{2-3}$$
$$-K^{q}_{i} a_{it} \le Q^{g}_{it} \le K^{p}_{i} a_{it} \tag{2-4}$$

Transmission Limits

$$|T_{ijt}| \le T^{\max}_{ij}\, b_{ijt} \tag{2-5}$$
$$V^{\min}_{i} \le |V_{it}| \le V^{\max}_{i} \tag{2-6}$$

where,

$E[\bullet]$: expected value of the argument,
i : bus (or customer class consisting of customers having same outage cost at a particular location)
I : total number of buses (or total number of customer classes)
t : short discrete time interval
T : total (study) time period
$F_{it}(P^{d}_{i}, Q^{d}_{i})$: short-run va1ue-added function of customer at bus i at time t,
P^{g}_{it} : generation of real power by generator at bus i at time t,
Q^{g}_{it} : generation of reactive power by generator at bus i at time t,
P^{s}_{it} : emergency purchase of real power at bus i at time t,
Q^{s}_{it} : emergency purchase of reactive power at bus i at time t,
P^{u}_{it} : outage of real power for customer at bus i at time t,
Q^{u}_{it} : outage of reactive power for customer at bus i at time t,
P^{d}_{it} : real power demand of customer at bus i at time t,
Q^{d}_{it} : reactive power demand of customer at bus i at time t,
Y_{ij} : ij^{th} term of the bus admittance matrix,
V_{it} : voltage at bus i at time t,
θ_{ij} : phase angle of the admittance Y_{ij},
δ_{it} : voltage angle at bus i at time t,
a_{it} : stochastic binary variable (0 or 1)
b_{ijt} : stochastic binary variable (0 or 1)
$|T_{ijt}|$: magnitude of the volt-ampere flow over the line and
$T^{\max}_{ij}$: capacity of the line connecting buses i and j,
K^{p}_{i} : real power generation capacity of generator at bus i,
K^{q}_{i} : reactive power generation capacity of generator at bus i,
$T^{\max}_{k}$: volt-ampere transmission capacity of line k
$OC_{it}(P^{u}_{i}, Q^{u}_{i})$: outage cost function of customer i,
$PC_{it}(P^{g}_{it}, Q^{g}_{it})$: cost of producing real and reactive power at bus i,
$EC_{it}(P^{s}_{it}, Q^{s}_{it})$: cost of purchasing real and reactive power at bus i.
$CC_{i}(K^{p}_{i}, K^{q}_{i})$: capital cost of capacity for generator i,
$SC_{i}(S^{p}_{i}, S^{q}_{i})$: purchase price of spinning reserve at bus i,
$TC_{k}(T^{\max}_{k})$: capital cost of capacity for transmission line k.

Other physical constraints, such as security constraint, distortion constraints, and environmental constraints can be added. All decision variables, except those involving reactive power, are nonnegative and the objective function is assumed to be differentiable with a continuous first derivative. For the optimal operating and pricing strategies, this objective function is maximized subject to the operating and network constraints inherent in the system

Now this problem can be solved, taking P^{d}_{it} and Q^{d}_{it} to be parameters of the problem, to obtain optimal values of all variables as functions of the parameters, i.e. P^{d}_{it} and Q^{d}_{it} (Sensitivity Theorem). Thus the objective function can be written as

$$W_{opt} = \sum_t \{ \sum_i F_{it}(P^{d}_{i}, Q^{d}_{i}) - \sum_i OC_{it}(P^{d}_{t}, Q^{d}_{t}) - PCtPtd,\ Qtd - ECtPtd,\ Qtd - iCCiPd,\ Qd - \sum_i SC_i(P^d, Q^d) - \sum_k TC_k(P^d, Q^d) \tag{3}$$

where, $P^d = \{P^{d}_{it};\ \forall\, i \in I,\ \forall\, t \in T\}$
$Q^d = \{Q^{d}_{it};\ \forall\, i \in I, \forall\, t \in T\}$

Since the customer sets his expected net marginal benefit from consumption of electricity equal to the expected price of electricity, the optimal long-term prices for real and reactive power, respectively, that induce the customers to behave in a social welfare maximizing manner are given by:

$$P^{L}_{jt} = \sum_{i \ne j} \frac{\partial OC_{it}}{\partial P^{d}_{jt}} + \frac{\partial PC_{t}}{\partial P^{d}_{jt}} + \frac{\partial EC_{t}}{\partial P^{d}_{jt}} \tag{4}$$
$$q^{L}_{jt} = \sum_{i \ne j} \frac{\partial OC_{it}}{\partial Q^{d}_{jt}} + \frac{\partial PC_{t}}{\partial Q^{d}_{jt}} + \frac{\partial EC_{t}}{\partial Q^{d}_{jt}} \tag{5}$$

Thus, under socially optimal investment decisions, long-term prices of real and reactive power coincide with short-term reliability differentiated prices.

3. Implications for Pricing Firm Capacity

Firm capacity is generating capacity that is purchased by the utility from neighboring utilities, independent power producers (IPP), and cogenerators in order to provide customers with higher levels of service reliability in the long-run. One of the benefits of firm capacity purhase is the possible postponement or cancellation of new capacity addition by the utility which may result in investment cost savings, especially since firm capacity purchase is often cheaper than adding new capacity. The price paid for firm capacity should equal the value, or marginal benefit, that customers derive from that additional capacity.

The purchase of fIrm capacity is a long-term contract made to protect against loss of customer load due to unplanned outage of generating units. Thus, to determine an optimal price of firm capacity purchase, consider the long-run problem of the welfare maximizing utility given in Eqs. (2.1)-(2.6). Again, this problem can be solved to obtain optimal values of all variab1es as functions of the parameters of the problem, in particular K_i^p and K_i^q (Sensitivity Theorem).

Since the shadow price of capacity addition (i.e. the Lagrange multiplier of the capacity Constraint) represents customer willingness-to-pay for that capacity addition, the optimal firm capacity purchase prices at bus j for real and reactive power capacity, respectively, are given by (assuming optimal short-run and long-term decisions are made by the utility as well as the customers, and after mathematical manipulation similar to that used in deriving Eqs. (4) and (5):

$$\mu_j^P = -\sum_{t\in T}\left\{\sum_i \frac{\partial OC_{it}}{\partial K_j^P} + \frac{\partial PC_t}{\partial K_j^P} + \frac{\partial EC_t}{\partial K_j^P}\right\} \quad (6)$$

$$\mu_j^q = -\sum_{t\in T}\left\{\sum_i \frac{\partial OC_{it}}{\partial K_j^q} + \frac{\partial PC_t}{\partial K_j^q} + \frac{\partial EC_t}{\partial K_j^q}\right\} \quad (7)$$

where T is the term of the firm capacity purchase contract. Thus the optimal firm capacity purchase prices for real and reactive power capacity consist of two parts: (i) The present value of expected marginal change in the cost of supplying electrical energy due to incremental change in firm capacity purchase, i.e. $-\sum_{t\in T}\left\{\sum_i \frac{\partial PC_t}{\partial K_j^P} + \frac{\partial EC_t}{\partial K_j^P}\right\}$ for real power capacity, which depends on the purchase price of electrical energy from that firm capacity contract; and (ii) The present value of expected marginal reduction in outage costs of all customers due to incremental change in the firm capacity purchase prices for real and reactive power capacity are affected by the operating conditions and constraints included in the model [Eq. (2.1)-(2.6)].

The purchase of firm capacity impacts both the total generation costs of the system and the outage costs of all customers. Thus, as one would expect, the price of firm capacity purchase reflects the present value of expected benefit from that capacity in the form of reduced customer outage costs and costs of operation.

4. Case Study: Calculation of Long-Term Rates

Consider the simple four-bus case study system of Fig. 1. In the figure, Gi and Li represent generating unit and load at Bus-i and. Ti represents transmission line-i. The characteristics of the system are as follows:

G1 : Rating = 200 MW, FOR= 0.00,
Generation cost = 30 \$/MWH
G2 : Rating = 250 MW, FOR= 0.10,
Generation cost = 0 \$/MWH
G3 : Rating = 110 MW, FOR = 0.00,
Generation cost = 40 \$/MWH
G4 : Rating = 250 MW, FOR = 0.20,
Generation cost = 20 \$/MWH

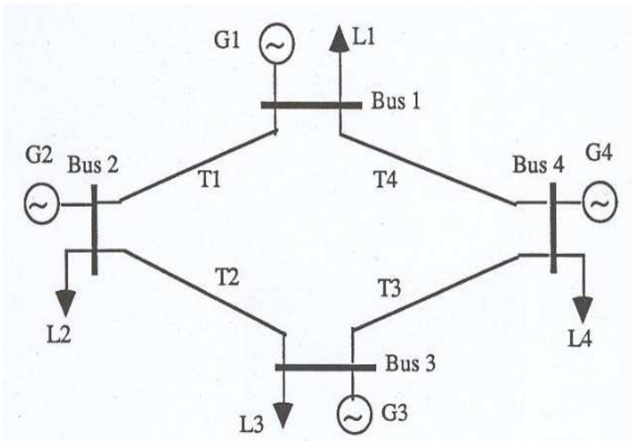

Fig. 1. Four-Bus Power System for Case Study

L1 : Customer load =180 MW, Outage cost = 600\$/MWH
L2 : Customer load =150 MW, Outage cost = 200\$/MWH
L3 : Customer load = 100 MW, Outage cost = 600\$/MWH
L4 : Customer load = 200 MW, Outage cost = 400\$/MWH
T1 : Rating = 100 MW, FOR = 0.00
T2 : Rating = 120 MW, FOR = 0.00
T3 : Rating = 80 MW, FOR = 0.30
T4 : Rating = 80 MW, FOR = 0.00
(FOR: Forced Outage Rate)

The system described above is a simple linear system that will be used to illustrate how reliability differentiated prices for this system can be hand calculated, when line losses and reactive power flows are neglected. In the model, there are two generating units (G2, G4) and one transmission line (T3) with non-zero FORs. Thus, at each instant in time, there are eight possible system configurations or states that the system can be in. The load at each bus is assumed to consist of 1 MW individual customer loads of customers belonging to the same customer class, i.e. having the same outage cost. Assuming that the system is operated optimally by a single welfare maximizing utility, the levels of generation, transmission, customer outage, marginal generation cost, and marginal outage cost for the different outage states of the system are summarized in Table 1.

Table 1. Sample Caculations for Single Utility System

STATE	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	Expected Value
Pro-bability	0.504	0.056	0.126	0.216	0.014	0.024	0.054	0.006	1.000
PU2	0	70	30	0	150	70	0	150	12.38
PU4	0	0	40	0	170	0	120	170	14.92
PG1	130	200	200	130	200	200	200	200	149.60
PG2	250	-	250	250	-	-	250	-	225.00
PG3	0	110	110	0	110	110	60	110	28.10
PG4	250	250	-	250	-	250	-	-	200.00
T3	0	25	80	-	10	-	-	-	11.62
T4	50	25	80	50	20	50	80	30	53.46
ΔPC/ΔL1	30	0	0	30	0	0	40	0	23.76
ΔPC/ΔL2	30	0	0	30	0	0	40	0	23.76
ΔPC/ΔL3	30	0	0	30	0	0	40	0	23.76
ΔPC/ΔL4	30	0	0	30	0	0	0	0	21.60
ΔOC/ΔL1	0	200	200	0	400	200	0	400	49.20
ΔOC/ΔL2	0	200*	200*	0	-	200*	0	-	28.69
ΔOC/ΔL3	0	200	200	0	400	200	0	400	49.20
ΔOC/ΔL4	0	400	400*	0	400*	200	400*	400*	66.16
RTP2	30	200	200	30	400	200	40	400	72.96
RTP4	30	400	400	30	400	200	400	400	117.60

(* For customers who are not cut off.)

In the description of state, bold letters used for generating units (G2, G4) and transmission line (T3) indicate that the unit or line is available, whereas plain letters indicate that unit or line is unvailable. PUi is unserved demand for customers class i, PGi is the power generated by generator i, RTPi is the reliability differntiated real-time price at bus i, and

$$\Delta OC/\Delta Lj = \sum_{i\neq j} \frac{\Delta OC_i}{\Delta L_j}$$

The expected reliability differentiated price for customers of class j is given by:

$$P_j = \sum_{i\neq j} \frac{\Delta OC_i}{\Delta L_j} + \frac{\Delta PC}{\Delta L_j}$$

Thus, the expected prices for the customer classes of the system are:

$$P_1 = \$72.96/\text{MWH} \quad P_2 = \$52.45/\text{MWH}$$
$$P_3 = \$72.96/\text{MWH} \quad P_4 = \$87.72/\text{MWH}$$

The probability of service interruption (POSI) for customers of each class, which measures the level of reliability with which each customer class is served, are:

Table 1. (Cont.) Sample Caculations for Single Utility System

STATE	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	G2G4 T3	Expected Value
Pro-bability	0.504	0.056	0.126	0.216	0.014	0.024	0.054	0.006	1.000
ΔPC/ΔG1	0	30	30	0	30	30	-10	30	6.24
ΔOC/ΔG1	0	-200	-200	0	-400	-200	0	-400	-49.20
ΔPC/ΔG2	-30	-	0	-30	-	-	-40	-	-23.76
ΔOC/ΔG2	0	-	-200	0	-	-	0	-	-25.20
ΔPC/ΔG3	0	40	40	0	40	40	0	40	9.04
ΔOC/ΔG3	0	-200	-200	0	-400	-200	0	-400	-49.20
ΔPC/ΔG4	-10	20	-	-10	-	20	-	-	-5.60
ΔOC/ΔG4	0	-200	-	0	-	-200	-	-	-16.00
ΔPC/ΔT3	0	0	0	-	0	-	-	-	0.00
ΔOC/ΔT3	0	0	-200	-	0	-	-	-	-25.20
ΔPC/ΔT4	0	0	0	0	0	0	40	0	2.16
ΔOC/ΔT4	0	0	-200	0	0	0	-400	0	-46.80
ΔOC/ΔL1	0	200	200	0	400	200	0	400	49.20
ΔOC/ΔL2	0	200*	200*	0	-	200*	0	-	28.69
ΔOC/ΔL3	0	200	200	0	400	200	0	400	49.20
ΔOC/ΔL4	0	400	400*	0	400*	200	400*	400*	66.16
RTP2	30	200	200	30	400	200	40	400	72.96
RTP4	30	400	400	30	400	200	400	400	117.60

$$POSI_1 = 0.0000 \quad OSI_2 = 0.0825$$
$$POSI_3 = 0.0000 \quad POSI_4 = 0.0746$$

The total expected cost of unserved energy for this linear system:

$$OC = \sum_i MOC_i PU_i = \sum_i \frac{\Delta OC_i}{\Delta L_i} = \$8{,}44.00$$

where MOC_i is the marginal outage cost of customer i (e.g.= MOC_2 = \$200/MWH).

The total expected revenue from the sale of electric power:

$$TR = \sum_i P_i L_i = \$45{,}848.80 \qquad \text{(A)}$$

The total expected cost of generation is:

$$PC = \sum_i MPC_i PG_i = \$9{,}612.00$$

where MPC_i is the marginal production cost of generator i (e.g. MPC_1 = \$30/MWH).

The price of capacity purchase from generator i is given by:

$$\mu_j = -\sum_j \frac{\Delta OC_j}{\Delta K_i} - \frac{\Delta PC}{\Delta K_i}$$

Thus the prices of capacity purchase from the generators of the system are:

μ_1 = \$42.96/MW $\quad$ μ_2 = \$48.96/MW
μ_3 = \$40.16/MW $\quad$ μ_4 = \$21.60/MW

The total payment to the generators for capacity purchase is:

$$CP = \sum_i \mu_i K_i = \$30{,}649.60$$

The price of capacity purchase from transmission line k is given by:

$$\eta_k = -\sum_j \frac{\Delta OC_j}{\Delta T_k^{\max}} - \frac{\Delta PC}{\Delta T_k^{\max}}$$

Thus the prices of capacity purchase from the transmission lines are:

η_1 = \$0.00/MW $\quad$ η_2 = \$0.00/MW
η_3 = \$25.20/MW $\quad$ η_4 = \$44.64/MW

The total payment to the transmission lines for capacity purchase is:

$$TP = \sum_k \eta_k T_k^{\max} = \$5{,}587.20$$

The sum total of all expected costs/payments for the system is:

$$TC = PC + CP + TP = \$45{,}848.80 \qquad (B)$$

Hence, refering to (A) and (B), under reliability differentiated pricing, the total expected revenue from sales to customers is exactly equal to the sum total of al1 expected costs/payments for the system, i.e. TR = TC. If the costs of capacity addition are also linear and investment in capacity is made in an optimal manner, then reliability differentiated pricing policy leads to prefect revenue reconciliation. This is evident from the fact that, according to the optimal investment criterion:

$$\frac{\Delta CC}{\Delta K_i} = -\sum_{t\in T}\left\{\sum_j \frac{\Delta OC_{jt}}{\Delta K_i} - \frac{\Delta PC_t}{\Delta K_i}\right\}$$

and the total capacity cost is given by:

$$CC = \frac{\Delta CC}{\Delta K_i}K_i = -\sum_{t\in T}\left\{\sum_j \frac{\Delta OC_{jt}}{\Delta K_i} - \frac{\Delta PC_t}{\Delta K_i}\right\}K_i$$

$$= \sum_{t\in T} \mu_{it} K_i$$

Thus the present value of the capacity payments over the operating life of the generating unit should equal the capacity cost of the generating unit. The same holds for transmission lines.

The simple model presented above brings to the forefront some of the salient features of reliability differentiated pricing policy. For example, the price a customer is expected to pay for electrical service is directly related to the level of reliability of service that the customer can expect to receive (POSI). Thus, customers having higher outage costs receive higher levels of service reliability and also have to pay a higher price for the service they receive. Another important feature of RDP policy is the existence of an allocation method for optimally allocating payments to particular pieces to equipment depending on the marginal benefit that customers derive from that particular equipment.

5. Conclusion and Future Study

It is known that Reliability Differentiated Pricing (RDP) can improve the efficiency and benefits of consumers and producers. This paper examines the long-run social welfare maximization problem of the utility and presents a long-term reliability differentiated prices for firm capacity, based on customer outage costs. With a case study, the applicability of the proposed pricing scheme to a firm capacity transaction is examined.

The novelty of the proposed pricing scheme lies in a fact that customer outage cost is adopted as a component of spot prices. At the same time, their theory is predicated on a number of assumptions that seem vulnerable to attack, particularly assumptions on outage cost and consumer behavior.

One of the timely interesting future studies will be an endeavour to expand the presented case study to AC problems and make it possible to implement the proposed pricing scheme on transmission services and thus determine optimal wheeling rates, including applying to an interconnected multi-utility system, followed by a study on revenue reconciliation problems.

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