Electric Power Systems Research 128 (2015) 66–78

Contents lists available at ScienceDirect

Electric Power Systems Research

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

Computation of strict long-run marginal cost for different HV consumers

Pandelis N. Biskas*, Grigorios A. Bakirtzis, Vasilis Chatziathanasiou

Department of Electrical Engineering, Aristotle University of Thessaloniki, Thessaloniki, 54124, Greece

ARTICLE INFO

Article history:
Received 30 December 2013
Received in revised form 9 March 2015
Accepted 29 June 2015
Available online 17 July 2015

Keywords:
Generation expansion planning
Long-run marginal cost
Marginal capacity cost
Marginal operating cost
Mixed-integer linear programming
Perturbation approach

ABSTRACT

In this paper the strict long-run marginal cost (LRMC) for the ratemaking of High Voltage (HV) consumers is computed, along with the constituent parts of LRMC, namely the marginal capacity cost and the marginal operating cost. The computation is performed using the perturbation approach, employing a generation expansion planning model in order to compute the optimal generation capacity expansion program that could cover the future increased demand. The perturbation is performed using realistic data from five HV consumers in Greece, which are used as demand increments for the overall system demand. The attained LRMCs are compared and conclusions are drawn regarding the effect of the consumption profile on the LRMC. A sensitivity analysis is performed considering an increasing demand increment for each HV consumer, in order to evaluate the effect of the increment magnitude on the LRMCs. Moreover, the Marginal Capacity Cost and the Marginal Operating Cost are computed in all cases. All tests are performed using the Greek electricity market, and the planning period for the LRMC computation is 20 years.

1. Introduction

The development of competitive electricity markets has laid increasing emphasis on the use of marginal cost pricing policies for the ratemaking of electricity consumption, instead of traditional utility tariff-setting design principles founded upon historical average cost studies. The goal of such studies is to calculate the cost components forming the utility's revenue requirement, in order to set rates sufficient to recover its costs (depreciation and financing costs, operation and maintenance costs, wages/administrative costs, fuel costs, etc.). All these procedures are essentially administrative, and although they are guided by the principle of cost causation, their factual basis is historical accounting information. Nowadays, the concept of marginal cost has a central place in pricing theory and practice, and especially in regulatory practice. According to the prevailing economic theory, prices should be set at marginal cost, since, in the absence of externalities, this maximizes economic welfare [1].

Marginal cost can be estimated in either a long-run (LRMC) or a short-run (SRMC) perspective. The fundamental difference between SRMC and LRMC is the timeframe under consideration [1]. SRMC depicts the marginal cost of supplying an additional unit of demand keeping the production capacity constant; the SRMC-based spot price reflects the shadow value or opportunity cost associated with an increment of either supply or demand [2]. On the other hand, LRMC is defined as the marginal cost of supplying an additional unit of electrical energy when the installed capacity of the system, under specified reliability standards, is allowed to increase optimally in response to the marginal increase in demand. As such, it incorporates both capital and operating costs. The value of LRMC reflects the marginal cost of optimal production capacity expansion (forward-looking model) required to support a marginal increase in demand within a pre-defined planning horizon. The choice of the optimal ratemaking method has been an issue of great controversy in the academic and professional society [3–8], most of their members advocating the LRMC-based method, since SRMC may lead to unacceptable instability in tariffs, especially in case of large High Voltage (HV) consumers. Additionally, it is not guaranteed that the capacity cost of the producers is covered from the short-term (daily) market, especially in pool-based markets as the one operating in Greece, Ireland and in most U.S wholesale markets (operated by Independent System Operators). For this reason in all these electricity markets separate capacity markets/mechanisms exist, in order producers to fully recover their capacity (fixed) costs.

* Corresponding author. Tel.: +30 2310 994352.
E-mail addresses: pbiskas@auth.gr, pbiskas@gmail.com (P.N. Biskas).

http://dx.doi.org/10.1016/j.epsr.2015.06.024
0378-7796/

Nomenclature

Indices and sets

$i(I)$	Index (set) of units
m (M)	Index (set) of yearly sub-periods (months)
j (J)	Index (set) of load levels
y (Y)	Index (set) of years within the planning horizon
s (S)	Index (set) of power stations
I^{old}	Set of units commissioned or with firm commissioning plans at the beginning of the planning horizon, $I^{old} \subseteq I$
I^{new}	Set of candidate new units to be selected during the planning horizon, $I^{new} \subseteq I$
I^{hyd}	Set of hydro units, $I^{hyd} \subseteq I$
I^{PES}	Set of Renewable Energy Sources (RES) units, $I^{RES} \subseteq I$. $I^{RES^+} = I^{RES} \cup I^{hyd}$

Parameters

Y	Last year of the planning horizon
y^{RES}	First year during which the RES quota target is effective
RES^y_{def}	Deficit from RES quota target during year y, in MWh
DF^y	Discount factor for year y, in p.u.
DR	Nominal discount rate, in p.u.
IR_f	Inflation rate for the supply cost of fuel f, in p.u.
IR_{CO_2}	Inflation rate for the CO_2 emissions price, in p.u.
$IR_{OM(i)}$	Inflation rate for the O&M cost (both variable and fixed part) of unit i, in p.u.
T_i^{life}	Expected lifetime of unit i, in years
T_i^{ini}	Age of unit i in the beginning of the planning horizon, in years. If negative, its absolute value represents the year of planned commissioning of the unit (with firm decision at a prior stage).
T_i^{con}	Construction time of unit i, in years.
f(i)	Fuel type of unit i, e.g. 'coal', 'gas', 'oil'
IHR_i	Incremental heat rate of unit i, in GJ/MWh
er_i	CO_2 emissions rate of unit i, in T/MWh
c_f	Price of fuel f, in €/GJ
c_{CO_2}	CO_2 emissions price at the first year of the planning horizon, in €/T
$c_{OM(i)}$	Variable part of the operation and maintenance (O&M) cost of unit i at the first year of the planning horizon, in €/MWh
$c_{FOM(i)}$	Fixed part of the O&M cost of unit i at the first year of the planning horizon, in €/MW-year
$h^{y,m,j}$	Duration of load level j of sub-period m of year y, in hours
$L^{y,m,j}$	System load in load level j of sub-period m of year y, in MW
ct_i^y	Marginal cost of unit i, including the variable part of the O&M cost and the CO_2 emissions cost, during year y, considering inflation, in €/MWh
P_i^{max}	Capacity of unit i, in MW
VLL^y	Value of lost load during year y, in €/MWh
PEN^y_{RES}	Penalty for not meeting RES quota target during year y, in €/MWh
$EFOR_i^{y,m}$	Equivalent Forced Outage Rate of unit i, during sub-period m of year y, in p.u.
E_i^y	Maximum electrical energy output of hydro unit i during year y, in MWh
ξ	Maximum RES penetration, in p.u.
λ^y	Minimum RES annual production requirement during year $y \geq y^{RES}$, in p.u. of annual demand.
ED^y	Electrical energy demand during year y, in MWh
C_i^{inv}	Specific investment cost of unit i, in €/MW
r^y_{min}	System minimum reserve margin for year y, in p.u.
B^y_{max}	Maximum budget for investment in generation expansion for year y, in €
$um_i^{y,m}$	Maintenance status of unit i in sub-period m of year y (equal to 1 when unit is on maintenance)

Variables

$P_i^{y,m,j}$	Power output of unit i at load level j during sub-period m of year y, in MW
$LNS^{y,m,j}$	Load not served during year y, sub-period m, at load level j, in MW
w_i^y	Binary variable representing the start-up decision (commissioning) of unit i in year y
z_i^y	Binary variable representing the shut-down decision (decommissioning) of unit i in year y
u_i^y	Binary variable representing the status of unit i in year y (equal to 1 if unit is commissioned)
Cost	Net Present Value of the total system cost in the GEP problem, in €
CapCost	Net Present Value of the system capacity cost in the GEP problem, in €
OperCost	Net Present Value of the system operating cost in the GEP problem, in €

LRMC-based pricing received wide popularity in many developed and developing countries. The pricing based on LRMC aims to send cost-reflective, economically efficient signals to producers and consumers, providing an economic climate for both supply and demand-side sustainable investment decisions, as well as for developing electricity tariff structures. LRMC-based pricing ensures efficient allocation of the resources and allows the recovery of the operating cost plus a reasonable rate of return on the invested capital.

The LRMC has been used extensively for the computation of charges of the transmission [9–18] and distribution network [19]. However, the literature on LRMC-based pricing for electricity consumption is limited. In [20] two methods for calculating LRMC for electricity production in Israel are presented, both based on Generation Expansion Planning (GEP) models. The first method calculates total LRMCs on seasonal basis (peak, shoulder and off-peak load) using the EGEAS model. In the second method, the marginal capacity cost is derived as in the first method, and the energy operating cost is derived on hourly basis from the chronological simulation model PWEEK. The results derived from the two models are compared, advocating the first one.

In [21] the software tool WASP-IV is used for the Generation Expansion Planning problem solution, in order to compute the strict LRMC, along with the marginal capacity cost and the marginal operating cost, for the electricity market of Oman. The application of (a) time-of-use (ToU) tariffs, and (b) different seasonal tariffs at different voltage levels, based on the attained LRMCs, is proposed, in order to decrease the consumption during peak hours.

In [22] LRMCs for different plant types (peak, off-peak, and partial-peak) are calculated using the capacity and energy costs, transmission and distribution costs, and spinning reserve and power availability. Based on LRMC values, ToU tariffs for different consumer categories in India are obtained. In [23] a Hungarian case study on the LRMC calculation of energy generation, transmission and distribution is presented. The attained results are proposed to set tariffs for large consumers in Hungary and to determine the price to be paid by the public utility to small producers connected to the power system. Finally, in [24] the LRMCs are computed for