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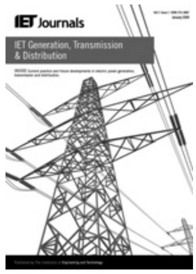

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Capacity adequacy calculation by considering locational capacity prices

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Abstract: A proper investment mechanism is required in restructured power systems to secure the adequacy of installed capacity by encouraging investments on generation and transmission expansions. In this study, the authors propose a locational capacity price (LCP) model along with multi-level load bidding curves, which reflect the effectiveness of the market-based capacity payment and at the same time, prohibits the capacity withholding and the exercising of market power. The purpose of capacity expansion decision is analysed and compared with three other market design options, that is, energy-only, capacity payment (CP) and installed capacity (ICAP). The case studies show that the proposed LCP method provides proper investment signals in capacity-constrained locations. The proposed LCP method also provides signals to system operators to alleviate transmission congestions economically using proper operation strategies in power systems.

Nomenclature

The symbols used in this paper are classified into indices, parameters, variables and matrices and vectors as follows:

Indices

max	subscript index for upper bound
min	subscript index for lower bound
g	subscript for GENCO
*	superscript for optimal value

Parameters

CUR	capacity usage rate
$E[\cdot]$	expected value
FOR	forced outage rate
$F(V)$	value of postponed investment
I	investment cost
LMP	locational marginal price
Load_{lijt}	forecasted bidding quantity of the load l at segment i and alternative j at time t
L	Lagrange function
lft	expected lifetime of the project
N_g	number of generator's bidding segments
NS_{lt}	number of bidding segments of load l at time t
NA_{lit}	number of alternatives at the bidding segment i of load l at time t
OC	average operating cost
$P_{g,t}$	dispatched power of generator g at time t
Pr_t	generator profit function
T	investment time parameter
wf	weighting factor
α	project value factor
ρ	discount rate
θ	bus angle
λ, κ, π, μ	Lagrangian multipliers

Variables

t	planning time variable
$L_{ij,t}$	accepted load quantity at the bidding segment i and alternative j at time t
V	value of the project

$U_{ij,t}$ load quantity binary integer variable at the bidding segment i and alternative j at time t; equal to 1 when the load bid is accepted and 0 when the bid is not accepted by the market

Matrices and vectors

$\boldsymbol{A}$ bus-unit incidence matrix

$\boldsymbol{B}$ bus-load incidence matrix

$\boldsymbol{b}$ bidding price vector of buyers

$\boldsymbol{c}$ bidding price vector of sellers

$\boldsymbol{H}$ bus-angle incidence matrix

$\boldsymbol{K}$ bus-branch incidence matrix

$\boldsymbol{P}$ bidding energy vector of sellers

$\boldsymbol{P}_{\mathrm{D}}$ bidding energy vector of buyers

$\boldsymbol{PL}$ real power flow in vector form

$\boldsymbol{X}$ line reactance vector

1 Introduction

Adequacy analyses would investigate the ability of power systems to provide a reliable supply of energy [1, 2]. In theory, the capacity adequacy is managed by market participants in a perfectly competitive market with provisions for the allocation of risks to consumers and suppliers [2]. However, the California market crisis showed that the market alone may not produce sufficient investment signals to guarantee the capacity adequacy. The main reasons which impede electricity markets from generating such investment signals include, but may not be limited to, flaws in the demand response, market power, excessive investment risks and ill-designed capacity markets [2, 3]. An exertion of market power is made possible by monitoring the gap between the marginal cost and real market prices [4, 5]. Insufficient energy market revenues to compensate capacity investments resulted in other market mechanisms, which included installed capacity (ICAP) and capacity payment (CP) [2]. ICAP deficiencies would include a lack of representation of locational- or temporal-based market prices. Furthermore, ICAP could provide a revenue source for generating units that are seldom committed or have only contributed to generation supply in peak periods. Such units may submit bids that are as high as price caps so that they do not participate in energy supply and get paid by ICAP [3, 6]. The CP mechanism may encourage market participants to exercise market power as insecure markets would tend to supply more CPs, that is, CPs could be the same as the value of lost load (VOLL) (i.e. market price cap) times a reliability index (e.g. loss of load probability). So generators would find it more profitable to pose artificial capacity deficiencies. In recent years, US electricity markets have reformed the capacity adequacy calculation mechanisms, which include the PJM's interconnections reliability pricing model (RPM), the ISO-NE's locational installed capacity (LICAP) model and the demand curve model considered in NYISO and MISO [7, 8]. There are other approaches to the capacity market, for example, call option [9, 10] and capacity subscription [11, 12], which are not widely implemented in electricity markets.

Our previous studies on the system capacity expansion [13–15] showed that a market-based signal would ensure sufficient and optimal investments in generation and transmission. Market mechanisms for the capacity adequacy were compared in [7] and concluded that a capacity mechanism is needed for resource adequacy, both in power pools and in transmission-constrained regions. Studies on energy-only market models for supplying an adequate capacity concluded that a greater transparency into market behaviours, supply and demand forecasts, and higher system-wide offer caps is needed to ensure the market success [16]. It also discussed that low price cap could result in under-investment in generation capacity [17]. Resource adequacy is a critical part of the reliability when demand response is insufficient or non-existent. Resource adequacy problems in several existing power markets were thoroughly discussed in [18]. In the literature, resource adequacy is classified into two main categories including short-term and long-term problems. Different aspect of the short-term capacity adequacy was elaborated in [19–21] and the long-term capacity mechanism was addressed in [22–24]. Another study showed that generation investment decisions could be evaluated based on the real options theory [25]. The real options theory presents new alternatives in investment strategies since it considers market uncertainties and options to invest when evaluating the value of project delays [26, 27].

In this paper, we utilise the real options theory for the modelling of investments under uncertainties. Such uncertainties include financial and physical risks pertaining to the time and the location of new capacity expansions. The proposed method compares net cash flows in two possible investment modes: (i) invest right after net present value (NPV) of the project becomes positive (instant decision) and (ii) consider a delay in investment to achieve the maximum profit (postponed decision). The rest of this paper is organised as follows. Section 2 discusses real options theory and its application in capacity expansion problem. Section 3 presents the proposed methodology and mathematical formulation. Section 4 in detail discusses the effectiveness of proposed approach in a sample two-bus system with three units and IEEE 118-bus system with 54 units. Section 5 provides the conclusions drawn from the proposed studies.

2 Investment in capacity with uncertainty

The capacity expansion mechanism introduces optimal the size, location, algorithm and time for new investments in power generation. Capacity investors consider the time for the implementation of new projects, a flexible item as compared to other decision attributes. Therefore we consider the investment time as a decision variable. We assume that the investment cost, I, is given. The finance theory indicates that the NPV is the best measure for evaluating new investments, which signals to invest as long as the V is larger than the discounted I, that is, the sum of discounted cash flows from the project is positive. However, this would lead to an incorrect result because the static NPV assessment does not consider the choice of deferring the investment. While future values of V are unknown, there is always an opportunity cost for investing today. Hence, the optimal investment rule is stated as make the investment when V is larger than a critical value V^* [26–28]. The value of investment opportunity, $F(V)$, in dollars is given as in (1), where V is the value of the project and a function of the planning time variable, t. On the other hand, the planning period includes the investment time and the lifetime of installed unit

$$F(V) = \max_t E[(V - I)\exp(-\rho t)] \tag{1}$$

where

$$V = V_0 \exp(\alpha t) \tag{2}$$

and

$$V_0 = \frac{V}{(1+\rho)^t} \tag{3}$$

Using (2) and (3), we obtain α as

$$\alpha = \ln(1+\rho) \tag{4}$$

in which $0 < \alpha < \rho$. In a deterministic model, the expectation function given in (1) would be eliminated. Therefore to maximise $F(V)$ with respect to t in (1), the first-order condition would be

$$\frac{\mathrm{d}F(V)}{\mathrm{d}t} = -(\rho - \alpha)V_0 \exp(-(\rho-\alpha)t) + \rho I \exp(-\rho t) = 0 \tag{5}$$

where $0 \le t \le T + lft$; which implies that the optimal investment time is

$$T^* = \max\left\{\frac{1}{\alpha}\ln\left[\frac{\rho I}{(\rho-\alpha)V}\right], 0\right\} \tag{6}$$

Accordingly, the decision to invest is made readily if V is sufficiently larger than I; otherwise $T^* > 0$ denotes the optimal investment time. The value of V^*, which corresponds to an immediate investment, is obtained by setting $T^* = 0$ in (4). So

$$V^* = \frac{\rho I}{(\rho - \alpha)} > I \tag{7}$$

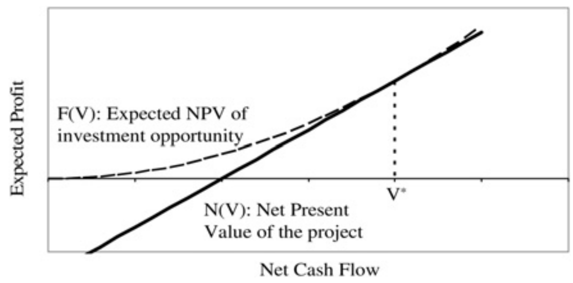

Figure 1 *Optimal investment time and value based on the real options theory*

Finally, by substituting (6) in (1), we obtain

$$F(V) = \begin{cases} [\alpha I/(\rho-\alpha)][(\rho-\alpha)V_0/\rho I]^{\rho/\alpha}, & V \le V^* \\ V - I, & V \ge V^* \end{cases} \tag{8}$$

and the NPV of the project, $N(V)$, is obtained as

$$N(V) = -\frac{I}{(1+\rho)^T} + \sum_{t=T}^{T+lft} \frac{V}{(1+\rho)^t} \tag{9}$$

The planning period, t, starts from the initial point of study and finishes at the end of the project lifetime. However, only a certain time in the planning period, t, is candidate for investment, T.

It is shown in Fig. 1, that the optimal investment time (6) is the intersection of (8) and (9). The intersection of $F(V)$ and $N(V)$ in Fig. 1 would determine V^* (or equivalently T^*), which is the optimal value and the time of the investment. In the following, we discuss the optimal investment and the time for capacity expansion.

3 Proposed capacity mechanism and formulation

In order to determine the optimal investment threshold, the market is simulated while the load is progressively increased during the lifetime of the installed generation unit. Here, we calculate the discounted project value (NPV) and determine the value of deferring the investment (forwarding value). The static NPV rule recommends that investors proceed with the project when $N(V)$ turns positive. However, we consider a more restrictive investment strategy by considering the option to wait for maximising the profit and minimising the risk. Fig. 2 shows the proposed capacity investment decision process using the real options theory. The flowchart simulates the market for the entire planning period (t). $N(V)$ is calculated in each year for the expected lifetime of generation unit and compared to $F(V)$. The optimal investment time occurs when $N(V)$ exceeds $F(V)$. If $N(V)$ is higher than $F(V)$ at the starting point, the investment decision can be made immediately. However, if the two curves do not intersect, the investment will not be profitable.

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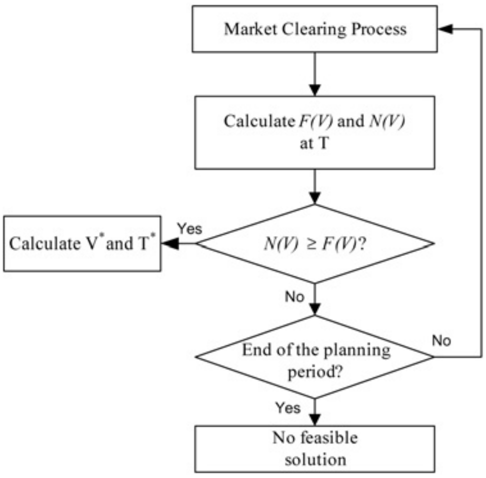

Figure 2 *Capacity expansion procedure using the real options theory*

The market-clearing model in Fig. 2 could represent energy-only, ICAP, CP or the proposed locational capacity price (LCP) approach. Regardless of the market mechanism, the objective is to maximise the social welfare (10) based on the prevailing power flow constraints including power balance (11), DC power flow (12), line flow limits (13), generation limits (14), demand range (15) and the reference bus angle constraint (16) [29]

$$\text{Max}\, \boldsymbol{b}^T\boldsymbol{P}_\text{D} - \boldsymbol{c}^T\boldsymbol{P} \tag{10}$$

s.t.

$$\boldsymbol{K} \times \boldsymbol{PL} - \boldsymbol{A} \times \boldsymbol{P} + \boldsymbol{B} \times \boldsymbol{P}_\text{D} = 0 \quad \lambda \tag{11}$$

$$\boldsymbol{PL} = \boldsymbol{X}^{-1}\boldsymbol{K}^T\theta \quad \kappa \tag{12}$$

$$-\boldsymbol{PL}_\text{max} \le \boldsymbol{PL} \le \boldsymbol{PL}_\text{max} \quad \underline{\pi}, \overline{\pi} \tag{13}$$

$$\boldsymbol{P}_\text{min} \le \boldsymbol{P} \le \boldsymbol{P}_\text{max} \quad \underline{\mu}_\text{P}, \bar{\mu}_\text{P} \tag{14}$$

$$\boldsymbol{P}_\text{D min} \le \boldsymbol{P}_\text{D} \le \boldsymbol{P}_\text{D max} \quad \underline{\mu}_\text{L}, \bar{\mu}_\text{L} \tag{15}$$

$$\theta_\text{ref} = 0 \quad \mu_\text{ref} \tag{16}$$

The generator revenue depends on the market structure and operation. We simulate the capacity expansion process using four models, including energy-only, ICAP, CP and LCP. We compare the corresponding investment efficiencies including the value and the time of project investment. The bus LCP is a positive (or zero) value, which is obtained from the base generator's maximum power capacity at a given bus. The base generator at a bus is the one with the lowest bidding price and the highest capacity usage rate. The capacity usage rate is given as

$$\text{CUR}_{gt} = \frac{P_{gt}}{P_{g,\max}} \tag{17}$$

Using (10)–(16), the Lagrange function is

$$\begin{aligned} L = {} & \boldsymbol{c}^T\boldsymbol{P} - \boldsymbol{b}^T\boldsymbol{L} + \lambda^T(\boldsymbol{K}\cdot\boldsymbol{PL} - \boldsymbol{A}\cdot\boldsymbol{P} + \boldsymbol{B}\cdot\boldsymbol{L}) \\ & + \kappa^T(\boldsymbol{PL} - \boldsymbol{X}^{-1}\boldsymbol{H}^T\theta) + \overline{\pi}^T(\boldsymbol{PL} - \boldsymbol{PL}_\text{max}) \\ & + \underline{\pi}^T(-\boldsymbol{PL}_\text{max} - \boldsymbol{PL}) + \bar{\mu}_\text{P}(\boldsymbol{P} - \boldsymbol{P}_\text{max} - \Delta\boldsymbol{P}_\text{max}) \\ & + \underline{\mu}_\text{P}(\boldsymbol{P}_\text{min} - \boldsymbol{P}) + \mu_\text{L}^{-T}(\boldsymbol{P}_\text{D} - \boldsymbol{P}_\text{D max}) + \underline{\mu}_\text{L}^T(\boldsymbol{P}_\text{D min} - \boldsymbol{P}_\text{D}) \\ & + \mu_\text{ref}\,\theta_\text{ref} \end{aligned} \tag{18}$$

The bus LCP, which is the shadow capacity price of the base generator, is given as

$$\text{LCP} = -\frac{\partial F}{\partial \Delta \boldsymbol{P}_\text{max}} = \bar{\mu}_\text{P} \tag{19}$$

The rationale for using LCP as a capacity signal is that by increasing the number of fully-loaded units in a bus, the Lagrange multiplier corresponding to the base generator's capacity constraint will increase. Assume that bids of N_g generators are $C_1, C_2, \ldots, C_{N_g-i}, \ldots, C_{N_g}$, where $C_1 < C_2 < \cdots < C_{N_g-i} < \cdots < C_{N_g}$. By disregarding the operating constraints and assuming that the generation units bid at their maximum capacity, when N_g generators are in service, at least $(N_g - 1)$ generators are at their capacity and only the most expensive generator may be loaded partially. So by adding one MW to the capacity of generator 1, P_{N_g} will decrease by one MW and P_1 will increase by one MW. Accordingly, the change in social welfare will be $(C_{N_g} - C_1)$. Hence, the change in the social welfare ($\bar{\mu}_\text{P} = \text{LCP}$) is larger when there are N_g generators as compared to $(N_g - i)$, that is, $(C_{N_g} - C_1) > (C_{N_g-i} - C_1)$. Hence, LCP is a capacity signal. The higher the LCP, the more capacity-constrained the system will be at a bus, which encourages a capacity investment to relieve capacity scarcity. The generators' bidding value and the changes in social welfare for each mode are shown in Fig. 3.

In the locational capacity model, generators would have income for selling electricity at LMP in addition to earning

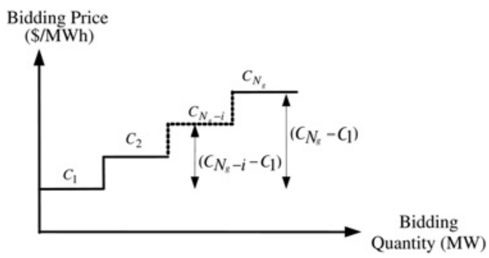

Figure 3 *Generators' biding price and change in the social welfare*

revenues equal to the LCP times the available capacity (20)

$$\mathrm{Pr}_{gt} = \sum_{t=T}^{T+lft} [(\mathrm{LMP}_t - \mathrm{OC}_{gt})P_{gt} + \mathrm{wf}\,\mathrm{LCP}_t\, P_{\max}(1 - \mathrm{FOR}_g)] \tag{20}$$

Here, we assume $P_{\max}(1 - \mathrm{FOR}_g)$ is the available capacity of generating unit. A weighting factor is considered in (20) to limit the overpayment by consumer and prevent unacceptable reductions in consumptions as a result of higher prices.

4 Case study and discussions

In this section, the capacity expansion problem is analysed in a two-bus system and investment conditions are discussed in various market structures, including the proposed LCP model. An IEEE 118-bus system is also used to evaluate the effectiveness of proposed approach.

4.1 Two-bus system

A two-bus system with two existing generators, one candidate generator, and a single load point is considered to illustrate the case. The simplicity and the limited number of elements in the two-bus system would make it much easier to analyse the effect of market structure on investment decisions, which is the main contribution of this paper. Fig. 4 shows a single diagram of the test system. Generation data are provided in Table 1. The 1900 MW load located in bus 2 will increase at a fixed annual rate of 5%. The transmission constraint is not considered. Investment period is 10 years ($T \in \{1, 2, 3, \ldots, 10\}$) and the unit expected lifetime is assumed to be 15 years. Therefore the maximum planning time would be 25 years. It is assumed that the new installed unit comes to operation at T and the construction time is one year. So the earliest time for a unit to come into service would be one year after the planning period has started, that is, $T = 1$. Table 2 presents the initial generation and the loading condition and price bids. It is assumed that generating units would bid at their marginal price level, which is known.

Figure 4 *Single diagram of the two-bus system*

Table 1 Generators data

Bus no.	Investment cost, \$/MW/year	Capacity, MW	FOR, %	Existing (E) or candidate (C)?
1	—	2000	0.1	E
2	—	2000	0.1	E
2	220 000	2000	0.1	C

Table 2 Generators and load bidding data

Unit name	Bidding segment no.	MW	Bidding price, \$/MWh
G1	1	1000	20
G1	2	600	25
G1	3	400	35
G2	1	1000	38
G2	2	600	40
G2	3	400	45
G3	1	1000	30
G3	2	600	36
G3	3	400	39
load	1	$L_{\mathrm{peak},t}/2$	51
load	2	$L_{\mathrm{peak},t}/3$	47
load	3	$L_{\mathrm{peak},t}/6$	44

4.1.1 Energy-only model: In the energy-only model, the market is supposed to provide sufficient incentives to ensure optimal investments in generation expansion. In theory, an ideal competitive spot market along with ancillary services must identify the key elements necessary for securing the short-term grid operations while maintaining the long-term grid reliability. The power markets in Scandinavia, United Kingdom, Australia, ERCOT and MISO have implemented such models. The latter two markets consider scarcity pricing while developing bilateral forward contracts through energy-only markets and legislating proper rules to ensure the active participations of demand side in wholesale markets.

In the energy-only model, electricity sales are the only sources of revenue and the capacity scarcity premium is not paid to generation owners. In our study, the market is simulated during the expected lifetime of a new generation. In this market, generators seek to be compensated for high investment costs through price spikes. However, price spikes may not occur often and as expected, which could increase the investor's financial risks. In such cases, generators can benefit from market volatilities which themselves are impediments for investment.

In this case, VOLL is assumed to be 1000 \$/MWh and no price cap is considered. Therefore the price can jump up to the VOLL in scarcity periods [30]. The profit function,

Pr_t, is given in (21). The market objective is to maximise the social welfare, while in a competitive market a more appropriate objective for individual investors is to maximise the expected profit. However, in a perfect power market, investment decisions based on a centralised social welfare maximisation and a decentralised profit maximisation would lead to the same results [31]

$$\mathrm{Pr}_{gt} = \sum_{t=T}^{T+lft} (\mathrm{LMP}_t - \mathrm{OC}_{gt})^* P_{gt} \quad (21)$$

Fig. 5 shows that $V^* = \$83.317$ million and $T^* = 4.021$ years. Hence, T is an integer parameter, and a linear approximation is applied to find the optimal investment time. The project NPV becomes positive at 3.421 years. If an investor applies the static NPV assessment, instead of the real options approach, the investment will be possible as soon as the NPV is positive [32]. However, the investment will be more profitable at T^*.

4.1.2 ICAP model: The application of ICAP in an installed capacity model requires the load serving entities (LSEs) to buy more power than their expected peak capacity in a long-term market, so that they can guarantee a prescribed level of generation capacity. ICAP showed market deficiencies such as providing revenues to the generating units that rarely (or never) were committed. The ICAP model is not affected by the location or time, that is, late nights and weekends are treated the same as peak hours in hot summers. In essence, there is an incentive for the generation investment in areas with high LMPs. However, ICAP payment can eliminate locational differences in energy prices [33]. This model was adopted in PJM, NY-ISO and NE-ISO before such markets reconsidered the process. Fig. 6 shows the ICAP study results. In this model, LSEs are required to buy 10% more than their expected peak load. The price of ICAP is determined administratively or based on long-term capacity markets. In this case, $V^* = \$111.26$ million and $T^* = 3.267$ while the NPV of project becomes positive at 2.637 years. The dynamic investment assessment [32] would result in postponing the investment decision. However, when the demand is increased in the ICAP model, the system becomes capacity-constrained earlier as compared to energy-only market and it will be more profitable for generators to make early investments. The

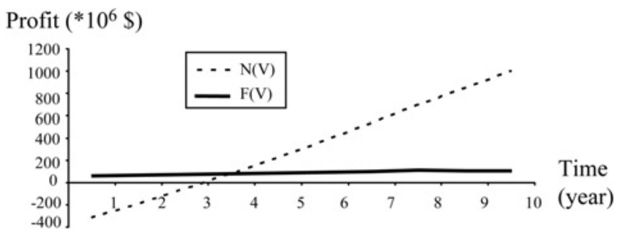

Figure 5 *Expected profit with F(V) and N(V) models in energy-only market*

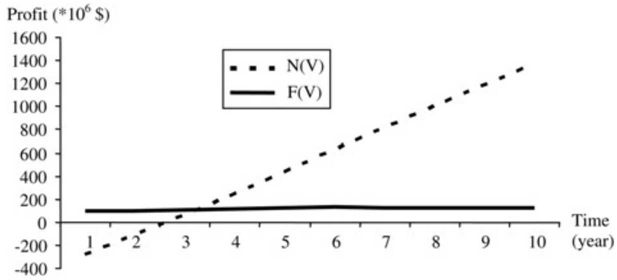

Figure 6 *Expected profit with F(V) and N(V) models in ICAP market*

project value is increased since there is a revenue source for the ICAP.

4.1.3 CP model: Generators in the CP model have an opportunity to earn revenues through regulatory mechanisms as well as energy markets. The additional payment is based on LOLP and VOLL. In this model, there is a regulatory price cap to hedge price spikes, which is significantly smaller than VOLL. Spain, Argentina, Colombia and Chile applied this market model. The main drawback of this model is that generators are inclined to pose artificial outages and exercise market power (e.g. delay the completion of scheduled maintenances or declare artificial outages).

One of the problems with the CP method is that, similar to the ICAP model, the payment is not based on locational attributes. In other words, an increase in LOLP will boost the CP for all generators even those which do not contribute to the system reliability or are located at a distance from capacity-constrained areas. Owing to the transmission constraints, remote generating units may not contribute to generation shortages. Therefore the CP incentive should follow a flexible paradigm (i.e. market-based) rather than providing a uniform revenue for the generating capacity, which does not encourage contributions to hedge power shortage. CP is distributed among generators according to their market contributions. However, at times, a small generation in a strategic location could be more vital than hundreds of megawatt in remote areas. Furthermore, in most cases VOLL is more of an administrative value, which may not show the willingness to pay off the loads and cannot be assumed as a decent signal for the capacity expansion.

Fig. 7 shows the result for the CP model. The CP is paid here to the available units according to their dispatchable installed capacity. In this case, $V^* = \$83.985$ millions and $T^* = 4.012$ years while the NPV of project becomes positive in 3.411 years. Here generators earn extra revenues from the capacity market. However, the market price cap would limit the value of project which is almost the same as that of the energy-only market model. Determining the price cap in markets with CP is a challenging task which can limit generator revenues. In an ideal market if the price cap is equal to the average VOLL, an optimal investment

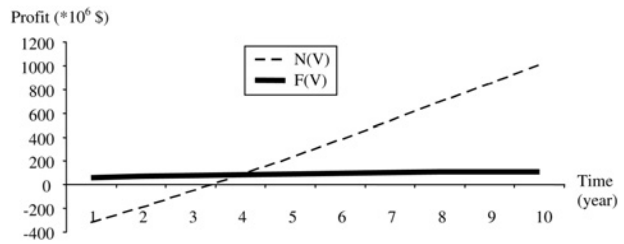

Figure 7 *Expected profit with F(V) and N(V) models in the CP market*

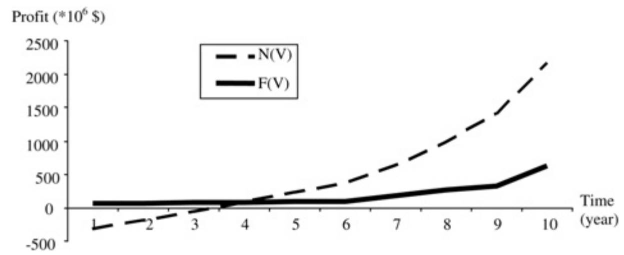

Figure 8 *Expected profit with F(V) and N(V) models in the LCP market*

along with the acceptable frequency of interruption will occur [34]. However, the average VOLL (e.g. 10 000 \$/MWh) is still significantly higher than the average electricity price (e.g. 50 \$/MWh). Therefore price caps as high as VOLL may not hedge price spikes. On the other hand, markets with low price caps may not be able to compensate generators, especially peaking units, for their fixed and variable costs.

4.1.4 LCP model: In this model, the LCP obtained from (19) is paid to generators as additional revenue. Fig. 8 shows the optimal investment time and value for the LCP approach. Comparing with the first three market models, we learn that the optimal investment occurs earlier, $T^* = 4.021$ and $V^* = \$83.317$ million. However, the static NPV rule proposes to invest even earlier at $T = 3.421$ years. The interesting result is that, compared to other capacity market mechanisms, the additional revenues in this framework would not obligate the investment to occur prematurely at earlier periods. Another common problem in markets with a capacity mechanism is that, over-investment may occur because of excessive incentive for new expansions. However, the LCP approach does not allow capacity incentives to unnecessarily increase the project value or consumer payments when the system does not require any capacity expansion. In this model, generation units can only obtain incremental profits by offering additional generation when the system becomes capacity-constrained, that is, LCP is the dual variable of the capacity constraint which is zero when the capacity is still available and the constraint is not binding. For instance, in year 7, the project value increases by about \$100M, which means the system is confronting capacity shortages. It is desirable to see the expansion at the right time before scarcity periods; however, when the system security is threatened by generation capacity shortages, LCP increases significantly which raises consumer charges as compared to those in the energy-only market. However, in the long-term LCP can ensure the adequacy of capacity which would benefit the system reliability along with consumer satisfactions.

In all the case studies, the discount rate is $\rho = 0.1$. A sensitivity analysis is performed to show the correlation between the results (i.e. optimal investment time and value) and discount rates. Table 3 shows that the investment time is delayed and the value of project is decreased by increasing the discount rate.

Multi-level load bidding: In this model, multi-level load bidding is considered. In Fig. 9 each load (or group of loads) submits a set of bids to the market according to its preferred demand level. The capacity index is introduced as a deduction margin below the peak demand for serving load. For instance, a 100 MW load with a capacity index of 0.1 is presented as 90 MW. This addresses the problem of demand overpayments in real markets when there is limited number of cheap units or generation capacity in general. Here, the overpayment refers to a case when a load would bid a certain MW value; however, when the market is cleared, the load is partially supplied at a high rate. A multi-level load bid allows loads to pay lower rates if they are partially supplied. In Fig. 9, the solid line represents the load's first priority to be served fully (Alternative 1), the dashed line shows the load tendency to stay in the market at 90% of its initial schedule (Alternative 2) and the grey-coloured line shows the load to be served at 80% (Alternative 3).

This forms an mixed-integer programming (MIP) problem in which the loads have i bidding segments and each segment has j alternatives that at most, one of these

Table 3 Sensitivity analysis on discount rate

discount rate (ρ)	0.01	0.05	0.10	0.15	0.20	0.25
T^* (year)	2.78	3.30	4.02	4.72	5.35	5.87
V^* (\$)	2.79×10^8	1.62×10^8	8.33×10^7	4.29×10^7	2.23×10^7	1.17×10^7

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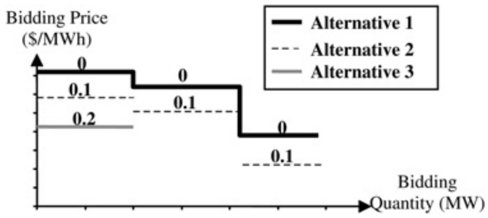

Figure 9 *Multi-level load bidding*

alternatives can be served in full or zero quantity

$$L_{ijt} = \sum_l \sum_i \sum_j U_{lijt} * \text{Load}_{lijt} \tag{22}$$

$$\sum_j U_{lijt} \leq 1 \quad \forall i = 1, 2, \ldots, \text{NS}_{lt}, \; \forall j = 1, 2, \ldots, \text{NA}_{lit} \tag{23}$$

Fig. 10 shows the market simulation results when the loads bid more than a single price at each segment. Here the optimal investment time and project value are the same as in Section 4.1.4. However, as shown in Fig. 10, when the system is on the verge of becoming capacity-constrained, the project value would change dramatically as the demand would provide more information on its tendency to be shed or not, that is, different level of price bids to minimise the

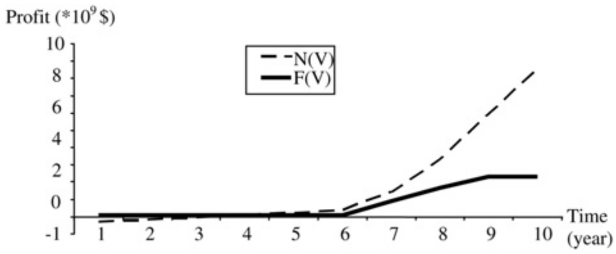

Figure 10 *Expected profit with F(V) and N(V) models in the LCP market with multi-level load bidding*

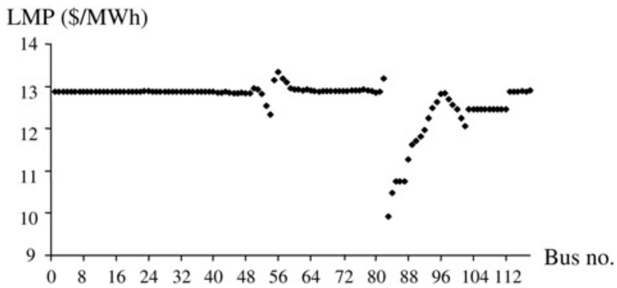

Figure 11 *Bus LMPs in the IEEE 118-bus*

load loss. As shown in Figs. 8 and 10, the trend in the project value would be different when we use the LCP rather than the other three approaches (Figs. 5–7). The major distinction in the LCP model is that the slope changes (increases) significantly, closer to the end of planning period, that is, scarcity periods. This makes sense, because generators are getting paid by LCP only if they reach their capacity limits. Since, the demand increases during the planning period, the chance of that new generator works at full capacity in ending years will be higher, and the value of the project is larger accordingly.

4.2 IEEE 118-bus system

A modified IEEE 118-bus system is used to study the proposed LCP approach. The system has 54 units, 186 branches, nine tap-changing transformers and 91 demand sides. The peak load is 3733 MW. The test data for the 118-bus system are given in motor.ece.iit.edu/data/SCUC_118test.xls. Fig. 11 shows the LMP results using the optimal power flow (DC-OPF). Here, bus 56 shows the highest LMP where there is an incentive to install new generating units [35]. Therefore we select bus 56 as a first candidate site for generation expansion. However, to investigate the effectiveness of LCP, we select buses 95 and 83 that represent an average and the lowest LMPs, respectively. Furthermore, buses 59 and 89 are considered

Table 4 Optimal investment time and value

Bus no.	LMP, \$/MWh	LCP model			Energy-only model		
		Optimal investment time, year		Optimal project value, M\$	Optimal investment time, year		Optimal project value, M\$
		$F(V)$	$N(V)$		$F(V)$	$N(V)$	
56	13.33	0	0	208.504	5.03	4.49	0.938
59	12.96	0	0	207.69	5.04	4.50	0.936
83	9.92	NI[a]	NI	−3.084	NI	NI	3.084
89	11.63	NI	NI	−3.084	NI	NI	−3.084
95	12.64	6.98	6.48	0.639	NI	NI	−3.029

[a]No investment.

as they have the largest installed load (277 MW) and transmission capacity accessibility (2600 MW), respectively. Similar to the study in Section 4.1, we simulate market operations for the expected life of the new generation and investigate the optimal timing and value for the expansion project. The new unit has the capacity of 200 MW and an operating marginal cost of 12.64 $/MWh. The load growth rate is assumed to be 1% over the lifetime of the project and the investment cost is the same as that in Section 4.1.

Table 4 shows the results for installing the new unit in different sites using the LCP and the energy-only market models. The investment here occurs in the earliest time and with the highest value of return. The investment in year 0 means that there is no reason to delay the expansion as soon as other constraints such as land acquisitions and project permits are met. As expected, it is not profitable to add any generation capacity in bus 83 with the lowest LMP. Bus 59 is a suitable candidate especially in transmission-constrained systems as it shows two positive factors including a high LMP and a large demand quantity. It is also profitable to choose bus 95 using the LCP approach. However, in all cases, the generation expansion would occur in earlier years if the locational capacity mechanism is considered in the market structure. Furthermore, investments would have a true market-based signal to find the best location for their expansion projects.

5 Conclusions

It was shown that with low VOLL values, the energy-only market model might not guarantee the capacity adequacy in power systems. Therefore it is essential to have a capacity mechanism to ensure that there will be enough capacity available to prevent the scarcity as the system load grows. CP and ICAP models have shown planning deficiencies because they do not include locational and temporal variables. Furthermore, the aforementioned capacity mechanisms may incur burdensome and excessive payments at demand side. The proposed LCP model provides an efficient solution for a market-based capacity mechanism while would not increase load payments if the new expansion has occurred at the right time, that is, before scarcity period. LCP brings about the following benefits:

- Allows cost-effective investments at earlier years before capacity shortages occur.

- Enables the creation of true capacity markets as it follows market trends and provides market-based investment signals.

- Provides generation companies with additional revenues to hedge investment risks.

- Encourages generation units to declare the available capacity in the market rather than exercising any market power.

- Is easily adapted to various market structures.

- Would not increase load payments in normal operation conditions.

Furthermore, the value of project provides investment signals when the system is on the verge of facing capacity shortages while risks are borne by investors rather than consumers. The ICAP model would lead to additional capacity investments while transferring considerable revenues, as capacity incentive payments, from consumers to suppliers. However, the LCP, along with multi-level load bidding would result in efficient capacity investments as well as a higher social welfare since it highlights consumer preferences for an uninterrupted supply. In the long-term, the proposed model will contribute to healthier electricity market designs and fewer administrative regulations in favour of robust capacity adequacy options.

6 References

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