Tri-level Expansion Planning for Transmission Networks and Distributed Energy Resources Considering Transmission Cost Allocation

Jianxiao Wang, *Student Member, IEEE*, Haiwang Zhong, *Member, IEEE*, Wenyuan Tang, *Member, IEEE*, Ram Rajagopal, *Member, IEEE*, Qing Xia, *Senior Member, IEEE*, Chongqing Kang, *Fellow, IEEE*

***Abstract*—Transmission cost allocation (TCA) is able to reflect energy users' contributions to the actual usage of transmission assets. A well-designed TCA scheme is able to incentivize the users to rationally consume energy and make investments for distributed energy resources (DERs). In this paper, a tri-level expansion planning framework for centralized transmission networks (TNs) and DERs is proposed, considering the effects of TCA. The proposed framework can be formulated as a market equilibrium model with three levels. On the first level, given the locational marginal prices (LMPs) and nodal transmission prices, the consumers at different nodes are strategically making investments for DERs, including wind turbines (WTs), photovoltaic systems (PVs) and energy storage systems (ESSs). Then the nodal net loads of the power system are changed with the investment of DERs. On the second level, transmission expansion planning (TEP) is optimized based on the updated nodal net loads, aimed at satisfying the requirements for transmission capacities. On the third level, based on the planning strategies for TNs and DERs, direct current optimal power flow (DCOPF) is employed to update the LMPs, and the transmission prices are updated using the power flow traction (PFT) approach. Due to the nonlinearity of the market equilibrium problem, an algorithm is presented to iteratively solve the tri-level model and a criterion is designed to acquire the optimal solution. Case studies based on a modified Garver-6 system and IEEE 118-bus system demonstrate that TCA is able to provide incentives for the users to invest in DERs, which effectively defers centralized TEP and reduces investment costs.**

***Index Terms*—Distributed energy resource, market equilibrium, transmission cost allocation, transmission expansion planning.**

NOMENCLATURE

A. Indices and Sets

t	Time index
s	Scenario index
k	Line index
x	Node index
DER	Superscript for DERs
LD	Superscript for load demands
NLD	Superscript for net load demands
WT	Superscript for WTs
PV	Superscript for PVs
ESS	Superscript for ESSs
LN	Superscript for transmission lines
G	Superscript for conventional generators
Ω^{PLN}	Set of candidate transmission lines
Ω^{LN}	Set of candidate and existing transmission lines
Ω_x^G	Set of conventional generators at node *x*
Ω^G	Set of conventional generators in the power system
Ω^{ULN}	Set of existing lines and the lines to be constructed

B. Parameters and Constants

$N^{(\cdot)}$	Number of DERs
N^S	Number of scenarios
γ_s	Weight of scenario *s*
T	Number of time slots
ΔT	Time interval
$IC_i^{(\cdot)}$	Investment cost of DER *i*
$IC_x^{\max}$	Investment budget at node *x*
$P_{(\cdot)}^{AWT}$	Available wind power
$P_{(\cdot)}^{APV}$	Available solar power
$P_{i,\alpha}^{ESS,\max}$	Maximal charging power of ESS *i*
$P_{i,\beta}^{ESS,\max}$	Maximal discharging power of ESS *i*
$\eta_{i,\alpha}^{ESS}$	Charging efficiency of ESS *i*
$\eta_{i,\beta}^{ESS}$	Discharging efficiency of ESS *i*
$SOC_i^{ESS,\min}$	Lower bound of the state of charge of ESS *i*
$SOC_i^{ESS,\max}$	Upper bound of the state of charge of ESS *i*
C_i^{ESS}	Capacity of ESS *i*
$P_{(\cdot)}^{LD}$	Load demands
IC_k^{LN}	Investment cost of transmission line *k*
$S(k)$	Sending-end bus of transmission line *k*
$R(k)$	Receiving-end bus of transmission line *k*
B_k^{LN}	Admittance of transmission line *k*
$P_k^{LN,\max}$	Transmission capacity of line *k*
$\delta_x^{\min}$	Minimal voltage phase angle of node *x*
$\delta_x^{\max}$	Maximal voltage phase angle of node *x*
$P_i^{G,\min}$	Minimal power of conventional generator *i*
$P_i^{G,\max}$	Maximal power of conventional generator *i*
c_i^G	Unit cost of conventional generator *i*
$GSDF_{k-i}$	Generation shifting distribution factor of line *k* to node *i*

N	Number of nodes in the power system
PTC_k	Transmission cost per unit power of line *k*

C. Variables

C_x^{DER}	Annualized investment for DERs at node *x*
C_x^{LD}	Annual cost of load demands at node *x*
$u_i^{(\cdot)}$	Binary decision variable of DER *i*. The value 1 indicates investing in DER *i*. Otherwise 0.
$\lambda_{(\cdot)}^{E}$	Locational marginal price
$\lambda_{(\cdot)}^{TC}$	Transmission price
$P_{(\cdot)}^{NLD}$	Net load demands
$\alpha_{(\cdot)}^{ESS}$	Binary variable of ESS representing the status of charging
$\beta_{(\cdot)}^{ESS}$	Binary variable of ESS representing the status of discharging
$P_{i,t,s,\alpha}^{ESS}$	Charging power of ESS *i* at time *t* in scenario *s*
$P_{i,t,s,\beta}^{ESS}$	Discharging power of ESS *i* at time *t* in scenario *s*
$E_{(\cdot)}^{ESS}$	Stored energy in the bank of ESS
u_k^{LN}	Binary decision variable of line *k*. The value 1 indicates investing in line *k*. Otherwise 0.
$P_{(\cdot)}^{G}$	Power of conventional generator
$P_{(\cdot)}^{LN}$	Power on transmission line
$\delta_{(\cdot)}$	Voltage phase angle
$P_{x,t,s}^{total}$	Total output power at node *x* at time *t* in scenario *s*
$\mathbf{P_{t,s}^{total}}$	Vector of total output power at each node in the power system at time *t* in scenario *s*
$\mathbf{P_{t,s}^{NLD}}$	Vector of net load demands at each node in the power system at time *t* in scenario *s*
$\mathbf{P_{t,s}^{LN}}$	Vector of power flows on each line in the power system at time *t* in scenario *s*
$TC_{x,t,s}$	Transmission costs allocated to node *x* at time *t* in scenario *s*

I. INTRODUCTION

A. Motivation

IN a market environment, a well-designed pricing mechanism is able to incentivize energy users to rationally consume energy and make investments for distributed energy resources (DERs). Transmission prices are important components of the users' electricity prices, employed to recover the fixed costs of transmission assets. In the Pennsylvania-New Jersey-Maryland (PJM) market, for example, the transmission price generally accounts for approximately 10% of the retail electricity price [1]. This value can reach 20% in the UK [2] and even higher in some other countries in Northern Europe. However, in the electricity markets across the world, transmission prices are generally determined annually based on the fixed costs and average usage of transmission assets [3]. For the energy users, the transmission prices are pre-defined and constant, which ignores the effects of time-varying load demands on the actual usage of transmission assets.

A fair transmission cost allocation (TCA) scheme should reflect energy users' contributions to the actual usage of transmission assets [4], thereby generating effective prices to guide the rational energy consumption and DER investments. For instance, by investing in DERs, the users should benefit from a lower transmission cost if the DERs are devoted to reducing the transmission capacity utilization. Therefore, a fair TCA scheme can boost the development of DERs by justifying the DER investments.

In the existing literature, distributed generation (DG) planning is aimed at minimizing the total costs over the period of return on investment (ROI), which ignores the influences of transmission costs. With the increasing generation of DERs at the demand side, the peak loads of the power system, as well as the actual usage of transmission assets, can be effectively reduced. The rapid development of DERs is helpful to defer the transmission expansion planning (TEP), which saves a large amount of centralized investment costs. According to the *incentive compatible principle* [5], the grid-friendly manner of investing in DERs should be rewarded with lower transmission costs. However, the existing literature cannot assess the contributions of TCA to the power system. As an important component of electricity prices, a fair transmission price is able to boost the development of DERs while deferring the centralized TEP. Therefore, it is essential to incorporate TCA in the expansion planning for transmission networks (TNs) and DERs, and evaluate the system benefits brought by TCA.

B. Literature Review and Contributions

The joint expansion planning strategies of the network and DG have been widely investigated in the past decades. In [6], the impacts of DG on transmission planning are evaluated by a TEP model. The uncertainties in the system load and market prices are modeled via stochastic processes, which can be incorporated in the TEP model. In [7], a distribution system planning model considering DG is presented. In that model, optimal power flow is adopted to minimize capital costs for network upgrading, operation and maintenance costs, and the costs for load growth. In [8], a tri-level model of transmission and generation expansion planning is developed. TEP is considered on the top level as a centralized decision. Then GenCos make their own capacity expansion on the second level while anticipating a wholesale electricity market on the third level. In [9], a joint expansion planning problem of the distribution network and DG is addressed. The expansion plan optimizes the installed location and time for the candidate assets by minimizing the investment and operation costs. In [10], an active distribution network planning model is presented, which is integrated with ESSs. The power supply reliability improvement brought by ESSs is analyzed by that model.

Most existing literature is focused on minimizing the investment and operation costs of candidate assets based on pre-defined electricity prices. To the best of our knowledge, few studies have considered TCA in the planning or assessed the contributions of transmission prices. However, a fair TCA scheme can incentivize the users to rationally consume energy and invest in DERs, thereby deferring centralized TEP. Hence, it is important to incorporate TCA in the expansion planning for TNs and DERs. In this paper, a tri-level expansion planning framework for TNs and DERs considering TCA is proposed for the first time. The expansion planning problem can be formulated as a market equilibrium model. On the first level, the consumers at different nodes are making investments for DERs given the locational marginal prices (LMPs) and nodal transmission prices. On the second level, based on the updated net loads after DER investments, the centralized TEP is optimized to satisfy transmission capacity requirements. On the third level, the LMPs and the transmission prices are updated by DCOPF and power flow traction (PFT) approach. Restricted by the nonlinearity of the market equilibrium problem, an algorithm is presented to iteratively solve the tri-level model and a criterion is designed to acquire the optimal solution. In addition, scenario-based stochastic programming is adopted to address the uncertainties in renewable generations and load demands. The major contributions of this paper are as follows:

1) A tri-level expansion planning model for TNs and DERs considering TCA is formulated for the first time. The consumers located at different nodes strategically invest in DERs on the first level. TEP is optimized on the second level and the nodal prices are updated on the third level.

2) The effects of TCA on the expansion planning for TNs and DERs are investigated. A fair TCA scheme can generate effective prices to guide the rational energy consumption and DER investments, thereby deferring centralized TEP.

3) Restricted by the nonlinearity of the market equilibrium problem, an algorithm is proposed to iteratively solve the expansion planning model. Convergence analysis is conducted and a criterion is designed to acquire the optimal solution.

II. Framework

The framework of the tri-level expansion planning for TNs and DERs considering TCA is shown in Fig. 1.

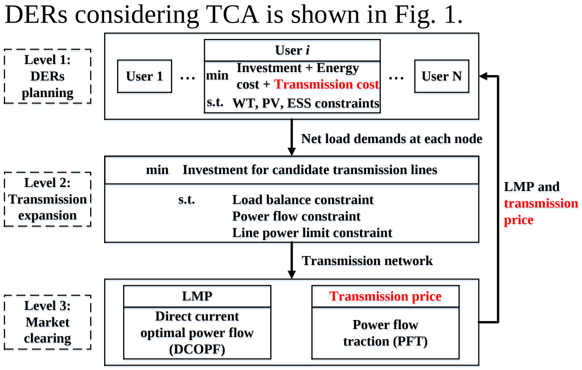

Fig. 1. The framework of the tri-level expansion planning.

The expansion planning for TNs and DERs considering TCA can be formulated as a market equilibrium problem with three levels. On the first level, given the LMPs and nodal transmission prices, the consumers at different nodes are strategically making investments for DERs, including WTs, PVs and ESSs. Then the net load demands at each node are updated according to the planning for DERs. On the second level, TEP is optimized to satisfy the requirements for transmission capacities. On the third level, based on the planning strategies for TNs and DERs, DCOPF is employed to update the LMPs, and the transmission prices are updated using the PFT approach. Then the tri-level planning model can be iteratively solved. Restricted by the nonlinearity of the market equilibrium problem, convergence analysis is conducted and a criterion is designed to determine the optimal solution.

III. Tri-level Model Formulation

In this section, the tri-level expansion planning model for TNs and DERs is formulated. In contrast to existing researches, the proposed planning model considers the influences of TCA. The transmission prices and LMPs are generated to lead the consumers investing in DERs. Hence, the net load demands can be effectively reduced, delaying the centralized TEP. To address the uncertainties in renewable generation and load demands, scenario-based stochastic programming is adopted.

A. First Level

On the first level, the DERs planning model is formulated to minimize the consumers' investment costs and electricity costs given the LMPs and transmission prices. The model of the DER investment at node x is as follows:

$$\min\ C_x^{DER} + C_x^{LD}, \tag{1}$$

subject to

$$C_x^{DER} = \sum_{i=1}^{N^{WT}} u_i^{WT} IC_i^{WT} + \sum_{i=1}^{N^{PV}} u_i^{PV} IC_i^{PV} + \sum_{i=1}^{N^{ESS}} u_i^{ESS} IC_i^{ESS}, \tag{2}$$

$$C_x^{LD} = \sum_{s=1}^{N^S} \gamma_s \sum_{t=1}^{T} \left(\lambda_{x,t,s}^{E} + \lambda_{x,t,s}^{TC}\right) P_{x,t,s}^{NLD} \Delta T, \tag{3}$$

$$C_x^{DER} \le IC^{\max}, \tag{4}$$

$$0 \le P_{i,t,s}^{WT} \le u_i^{WT} P_{i,t,s}^{AWT}, \forall i,t,s, \tag{5}$$

$$0 \le P_{i,t,s}^{PV} \le u_i^{PV} P_{i,t,s}^{APV}, \forall i,t,s, \tag{6}$$

$$0 \le \alpha_{i,t,s}^{ESS} + \beta_{i,t,s}^{ESS} \le u_i^{ESS}, \forall i,t,s, \tag{7}$$

$$0 \le P_{i,t,s,\alpha}^{ESS} \le \alpha_{i,t,s}^{ESS} P_{i,\alpha}^{ESS,\max}, \forall i,t,s, \tag{8}$$

$$0 \le P_{i,t,s,\beta}^{ESS} \le \beta_{i,t,s}^{ESS} P_{i,\beta}^{ESS,\max}, \forall i,t,s, \tag{9}$$

$$E_{i,t,s}^{ESS} = E_{i,t-1,s}^{ESS} + \left(P_{i,t,s,\alpha}^{ESS} \eta_{i,\alpha}^{ESS} - P_{i,t,s,\beta}^{ESS} / \eta_{i,\beta}^{ESS}\right)\Delta T, \forall i,t,s, \tag{10}$$

$$SOC_i^{ESS,\min} \le E_{i,t,s}^{ESS} / C_i^{ESS} \le SOC_i^{ESS,\max}, \forall i,t,s, \tag{11}$$

$$E_{i,0,s}^{ESS} = E_{i,T,s}^{ESS}, \forall i,s, \tag{12}$$

$$P_{x,t,s}^{NLD} = P_{x,t,s}^{LD} - \sum_{i=1}^{N^{WT}} P_{i,t,s}^{WT} - \sum_{i=1}^{N^{PV}} P_{i,t,s}^{PV} - \sum_{i=1}^{N^{ESS}} \left(-P_{i,t,s,\alpha}^{ESS} + P_{i,t,s,\beta}^{ESS}\right), \forall t,s. \tag{13}$$

Constraint (2) shows that the investment costs include the investments for WTs, PVs and ESSs, restricted by the investment budget in (4). In constraint (3), the electricity costs are composed of energy and transmission costs. Constraints (5) and (6) show that the generations of WTs and PVs are limited by the available power at each time slot. Constraints (7)-(9) show that the charging and discharging power of ESSs are restricted. $\alpha_{i,t,s}^{ESS} = 1$, $\beta_{i,t,s}^{ESS} = 0$ indicates that ESS i is charging. $\alpha_{i,t,s}^{ESS} = 0$, $\beta_{i,t,s}^{ESS} = 1$ indicates that ESS i is discharging. $\alpha_{i,t,s}^{ESS} = 0$, $\beta_{i,t,s}^{ESS} = 0$ indicates that ESS i is hanging up. Constraint (10) shows the dynamic process of the energy stored in the bank of ESS i. Constraint (11) shows the stored energy is bounded by the state of charge (SOC) of ESS i. In constraint (12), the stored energy at time slot T is set the same as the initial energy for the balance of ESS i. Constraint (13) shows that the net load is the difference between the load and the output of DERs.

B. Second Level

On the second level, the TEP model is established to minimize expansion investments while satisfying the requirements for transmission capacity. The model of TEP is as follows:

$$\min \sum_{k\in\Omega^{PLN}} u_k^{LN} IC_k^{LN} , \quad (14)$$

subject to

$$\sum_{i\in\Omega_x^G} P_{i,t,s}^G - P_{x,t,s}^{NLD} = \sum_{k|S(k)=x} P_{k,t,s}^{LN} - \sum_{k|R(k)=x} P_{k,t,s}^{LN}, \forall x,t,s , \quad (15)$$

$$P_{k,t,s}^{LN} - B_k^{LN}\left(\delta_{S(k),t,s} - \delta_{R(k),t,s}\right) = 0, \forall t,s,k \in \Omega^{LN} \setminus \Omega^{PLN} , \quad (16)$$

$$-P_k^{LN,\max} \le P_{k,t,s}^{LN} \le P_k^{LN,\max}, \forall t,s,k \in \Omega^{LN} \setminus \Omega^{PLN} , \quad (17)$$

$$P_{k,t,s}^{LN} - B_k^{LN}\left(\delta_{S(k),t,s} - \delta_{R(k),t,s}\right) + \left(1-u_k^{LN}\right)\mathrm{M} \ge 0, \forall t,s,k \in \Omega^{PLN} , \quad (18)$$

$$P_{k,t,s}^{LN} - B_k^{LN}\left(\delta_{S(k),t,s} - \delta_{R(k),t,s}\right) - \left(1-u_k^{LN}\right)\mathrm{M} \le 0, \forall t,s,k \in \Omega^{PLN} , \quad (19)$$

$$-u_k^{LN} P_k^{LN,\max} \le P_{k,t,s}^{LN} \le u_k^{LN} P_k^{LN,\max}, \forall t,s,k \in \Omega^{PLN} , \quad (20)$$

$$\delta_x^{\min} \le \delta_{x,t,s} \le \delta_x^{\max}, \forall x,t,s , \quad (21)$$

$$P_i^{G,\min} \le P_{i,t,s}^G \le P_i^{G,\max}, \forall i,t,s . \quad (22)$$

Constraint (15) shows the energy balance at each node. Constraints (16) and (17) are the power flow constraints for existing lines. Constraints (18)-(20) are the power flow constraints for candidate lines, where M is a large number greater than $B_k^{LN}(\delta_{S(k)}^{\max} - \delta_{R(k)}^{\min})$ for each line. Constraints (21) and (22) show the limits for voltage phase angles and generator outputs.

Note that consumers' planning strategies for DERs can change the nodal net load demands, which further influences the planning for TNs. With the investments for DERs, the net load demands and power flows on transmission lines can be effectively reduced, thereby deferring TEP and saving centralized investment costs.

C. Third Level

The third level is comprised of two models: i) Locational marginal pricing model and ii) Transmission pricing model. Based on the planning strategies for TNs and DERs, DCOPF is employed to compute the LMPs, and transmission prices are obtained using PFT.

1) LMP model

DCOPF has been widely used for computing LMPs in existing research and electricity markets, e.g., the Electric Reliability Council of Texas (ERCOT). The DCOPF model in scenario *s* at time slot *t* is as follows:

$$\min \sum_{i\in\Omega^G} c_i^G \times P_{i,t,s}^G , \quad (23)$$

subject to

$$\sum_{i\in\Omega^G} P_{i,t,s}^G = \sum_{i\in\Omega^{LD}} P_{i,t,s}^{NLD} : \lambda_{t,s} , \quad (24)$$

$$\sum_{i=1}^{N} GSDF_{k-i}\left(P_{i,t,s}^G - P_{i,t,s}^{NLD}\right) \le P_k^{LN,\max} : \mu_{k,t,s}^+, \forall k \in \Omega^{ULN} , \quad (25)$$

$$\sum_{i=1}^{N} GSDF_{k-i}\left(P_{i,t,s}^G - P_{i,t,s}^{NLD}\right) \ge -P_k^{LN,\max} : \mu_{k,t,s}^-, \forall k \in \Omega^{ULN} , \quad (26)$$

$$P_i^{G,\min} \le P_{i,t,s}^G \le P_i^{G,\max}, \forall i . \quad (27)$$

Note that Ω^{ULN} is updated with the TEP results. When the planning strategies for TNs and DERs are determined, the DCOPF model is to minimize the operational costs of conventional generators in the power system, subject to power balance constraints (24), line power flow constraints (25) and (26), and the limits for generators output (27). The Lagrangian multipliers of constraints (24)-(26) are denoted by $\lambda_{t,s}$, $\mu_{k,t,s}^+$ and $\mu_{k,t,s}^-$, respectively. Then the LMP at node *x* in eq. (3), $\lambda_{x,t,s}^E$ is:

$$\lambda_{x,t,s}^E = \lambda_{t,s} + \sum_{k\in\Omega^{ULN}} GSDF_{k-x}\left(\mu_{k,t,s}^+ + \mu_{k,t,s}^-\right) . \quad (28)$$

2) Transmission pricing model

In this paper, all transmission costs are assumed to be paid by consumers [4]. The PFT method is adopted to allocate the transmission costs to each consumer, described as follows.

The power flow of the system can be optimized using DCOPF. Then the total output power at node *x* is calculated as the sum of the net load and the transmission power from node *x* to other nodes, as follows:

$$P_{x,t,s}^{total} = \sum_{k|S(k)=x} P_{k,t,s}^{LN} + P_{x,t,s}^{NLD} . \quad (29)$$

To obtain the relationship between the total output power and the net load, eq. (29) is derived as follows:

$$P_{x,t,s}^{total} - \sum_{k|S(k)=x}\left(P_{k,t,s}^{LN} / P_{y,t,s}^{total}\right)\cdot P_{y,t,s}^{total}\big|_{y=R(k)} = P_{x,t,s}^{NLD} . \quad (30)$$

The matrix form is expressed as follows:

$$\mathbf{A_{t,s}}\mathbf{P_{t,s}^{total}} = \mathbf{P_{t,s}^{NLD}} , \quad (31)$$

where $\mathbf{A_{t,s}}$ is the relationship matrix, which can be derived from the power flows after DCOPF. The element a_{xy} of $\mathbf{A_{t,s}}$ in row *x* and column *y* is:

$$a_{xy} = \begin{cases} 1, \ x = y \\ -P_{k,t,s}^{LN} / P_{y,t,s}^{total}, \ S(k) = x, \ R(k) = y \\ 0, \text{ otherwise} \end{cases} . \quad (32)$$

Since $\mathbf{A_{t,s}}$ is invertible, then

$$\mathbf{P_{t,s}^{total}} = \mathbf{A_{t,s}^{-1}}\mathbf{P_{t,s}^{NLD}} . \quad (33)$$

The matrix $\mathbf{A_{t,s}^{-1}}$ represents the contributions of the net loads to the nodal total output power. The relationship between the line power flows and the nodal total output power is:

$$\mathbf{P_{t,s}^{LN}} = \mathbf{C_{t,s}}\mathbf{P_{t,s}^{total}} . \quad (34)$$

According to the *proportionate sharing rule*, the element c_{kx} of the matrix $\mathbf{C_{t,s}}$ in row *k* and column *x* is:

$$c_{kx} = \begin{cases} P_{k,t,s}^{LN} / P_{x,t,s}^{total}, \ R(k) = x \\ 0, \text{ otherwise} \end{cases} . \quad (35)$$

According to eq. (33) and (34), the relationship between the line power flows and the net loads is:

$$\mathbf{P_{t,s}^{LN}} = \mathbf{C_{t,s}}\mathbf{A_{t,s}^{-1}}\mathbf{P_{t,s}^{NLD}} = \mathbf{F_{t,s}}\mathbf{P_{t,s}^{NLD}} , \quad (36)$$

where the matrix $\mathbf{F_{t,s}}$ represents the contributions of the net loads to the line power flows. Then the transmission costs of all the lines allocated to node *x* are:

$$TC_{x,t,s} = \sum_{k\in\Omega^{ULN}} PTC_k \cdot f_{kx,t,s} \cdot P_{x,t,s}^{NLD} , \quad (37)$$

where $f_{kx,t,s}$ is the element of the matrix $\mathbf{F_{t,s}}$ in row *k* and column *x*. Hence, the transmission price $\lambda_{x,t,s}^{TC}$ in eq. (3), is:

$$\lambda_{x,t,s}^{TC} = \sum_{k \in \Omega^{ULN}} PTC_k \cdot f_{kx,t,s} \, . \tag{38}$$

IV. Solution Algorithm

The tri-level expansion planning model can be formulated as a market equilibrium problem. In this problem, the investment for DERs will influence the planning for TNs, which further has an impact on the equilibrium LMPs and transmission prices. Restricted by the nonlinearity of the market equilibrium problem, an algorithm is presented to iteratively solve the model and a criterion is designed to acquire the optimal solution.

A. *Procedure*

The procedure of the solution algorithm is shown in Fig. 2.

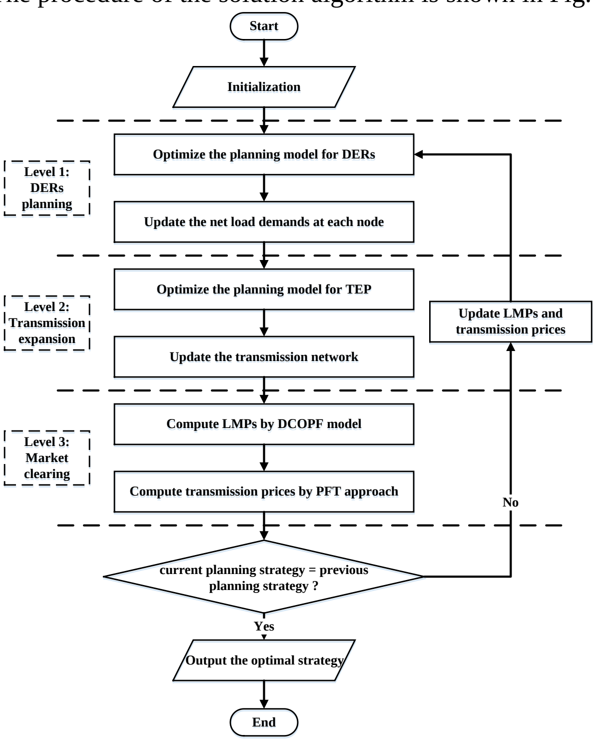

Fig. 2. The procedure of the iterative solution method.

1) Initialize the LMPs, the transmission prices, and other parameters required in the models.

2) Given the LMPs and transmission prices, the consumers located at different nodes optimize the planning model for DERs. Then the nodal net load demands can be obtained.

3) Given the nodal net loads, the TEP model is optimized to satisfy the requirements for transmission capacity. Then the transmission networks can be updated.

4) Given the updated TNs and the nodal net loads, the LMPs and the power flows are updated by DCOPF.

5) After the power flows of the system are determined, PFT is adopted to allocate the transmission costs to each node. Transmission prices can then be obtained.

6) If the current planning strategies for TNs and DERs are identical to the previous ones, output the optimal results, and the solution procedure terminates. Otherwise, go to 7).

7) Update the LMPs and transmission prices, which influences the consumers' planning for DERs. Go to 2).

B. *Convergence Analysis*

From an economic point of view, the iteration process can be described as follows. Initially, the consumers purchase electricity from the bulk power system at high prices without the investments for DERs. With the increase of the load demands, the transmission capacity is insufficient and the transmission network needs expanding. Then the transmission prices allocated to the consumers will further increase. To reduce the electricity and transmission costs, the consumers are economically driven to invest in DERs and strategically operate the DERs. With the help of DERs, the consumers can maximize the long-term revenues by saving the electricity and transmission costs, which also improves the penetration of DERs. Moreover, the net loads and the power flows of the system can be greatly reduced, which effectively defers transmission expansion.

Restricted by the nonlinearity of the market equilibrium problem, the convergence cannot be always guaranteed. Because the electricity and transmission costs vary with the planning strategies for DERs and TNs, the consumers will probably find that the reduction in electricity and transmission costs cannot make up the DER investment after investing in a DER. Then oscillations may occur in a dilemma between two situations: i) the consumers invest in the marginal DER, replacing the marginal transmission line. Then the consumers find it is not beneficial to invest in the DER. ii) the consumers do not invest in the marginal DER, leading to the expansion for the marginal transmission line. Then the consumers find it beneficial to invest in the DER because of an increase in transmission costs. The process is illustrated in Fig. 3, where the marginal DER is denoted by DER_n and the marginal transmission line is TN_n.

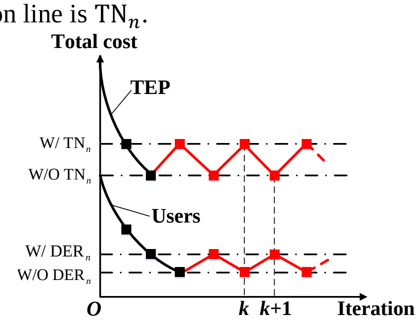

Fig. 3. Illustration of the iterative oscillation.

Considering the nonlinear nature of the tri-level planning model, it is difficult, if not impossible, to guarantee the optimality and convergence. Hence, a convergence criterion is designed as follows:

Convergence Criterion	
1	Find all the situations where oscillations occur during the iterations;
2	Based on the strategies for TNs and DERs in each situation, calculate the LMPs and transmission prices;
3	Calculate the energy and transmission costs of all the consumers in each situation;
4	Calculate the total costs of the system in each situation, including investments for TNs and DERs, the energy and transmission costs of the consumers, and the generation costs of conventional generators;

5 Find the situation with minimum total costs of the system, and the planning strategies in that situation are the optimal results.

The idea of the convergence criterion is to find the situation with maximum social welfare. In the criterion, the LMPs and transmission prices are used for settlement.

V. Case Studies

The testing environment is a ThinkPad T440p operating at 2.40 GHz with 8 cores. The program is developed with MATLAB R2015b. The optimization solver is CPLEX 12.4 [12]. In this section, a modified Garver 6-bus system and the IEEE 118-bus system are simulated to validate the proposed model. To address the uncertainties in load demands and renewable energy, scenario-based stochastic programming is adopted. The yearly power curves of wind, photovoltaic and load are collected from the wind farms, solar panels and substations in a province in China. Then 10 typical daily scenarios are generated by K-means clustering. The parameters of DERs are listed in TABLE I [13]. The transmission cost for all lines is 10 \$/h for a 1 MW capacity, i.e., $PTC_k = 10, \forall k$.

TABLE I
Parameters of DERs

DER	Investment cost (\$)		Capacity (MW)
WT	500,000		8
PV	180,000		6
ESS	Investment cost (\$)	$SOC_{i,\min}^{ESS}$	$SOC_{i,\max}^{ESS}$
	10,000	10%	90%
	C_i^{ESS}(MWh)	$\eta_{i,\alpha}^{ESS}$	$\eta_{i,\beta}^{ESS}$
	10	95%	95%
	$E_{i,0}^{ESS}$(MWh)	$P_{i,\alpha,\max}^{ESS}$(MW)	$P_{i,\beta,\max}^{ESS}$(MW)
	3	2	2

A. Modified Garver 6-Bus System

The modified Garver 6-bus system is shown in Fig. 4. The parameters of the centralized thermal units and the transmission lines are listed in TABLE II and TABLE III [14].

TABLE II
Parameters of Centralized Thermal Units

Unit No.	Node	$P^{G,\max}$ (MW)	Cost (\$/MWh)
1	1	30	10
2	3	20	40
3	6	50	70

TABLE III
Parameters of Transmission Lines

Line No.	From	To	Reactance (p.u.)	$P^{LN,\max}$ (MW)	Status	Investment (million \$)
1	1	2	0.4	10	Existing	/
2	1	4	0.6	8	Existing	/
3	1	5	0.2	15	Existing	/
4	2	3	0.2	15	Existing	/
5	2	4	0.4	10	Existing	/
6	2	6	0.3	10	Existing	/
7	3	5	0.2	10	Existing	/
8	2	4	0.4	10	Candidate	12
9	2	6	0.3	10	Candidate	10
10	2	6	0.3	10	Candidate	10
11	3	5	0.2	10	Candidate	10
12	4	6	0.3	6	Candidate	11
13	4	6	0.3	6	Candidate	11
14	4	6	0.3	6	Candidate	11

Two consumers, located at node 4 and 5, are respectively making investments for DERs. Each consumer has an annualized budget \$2,000,000 for candidate DERs, including 3 WTs, 3 PVs and 2 ESSs. To demonstrate the effects of TCA on the planning strategies of TNs and DERs, three scenarios are adopted: i) S1, where TEP is optimized without considering DERs; ii) S2, where DERs are planned only considering LMPs, and then TEP is optimized; and iii) S3, the proposed method, where DERs are planned considering both LMPs and transmission prices, and then TEP is optimized.

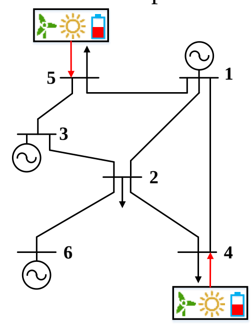

Fig. 4. The modified Garver 6-bus system.

1) Optimal Planning Strategy in S3

After 11 iterations, the optimal planning strategies reach the equilibrium and the computation time is 67.45 s. The planning strategies for DERs and TNs are shown in TABLE IV. Note that the value 1 represents the line is optimized to be constructed while 0 represents the line will not be constructed.

TABLE IV
Optimal Planning Strategies for DERs and TNs in S3

DER	WT		PV		ESS		
Node 4	3		2		2		
Node 5	2		0		2		
Line No.	8	9	10	11	12	13	14
Result	1	1	1	0	0	0	0

In S3, the consumers at node 4 will invest in 3 WTs, 2 PVs and 2 ESSs, and the consumers at node 5 will invest in 2 WTs and 2 ESSs. In addition, 3 transmission lines will be constructed to satisfy the transmission capacity requirement.

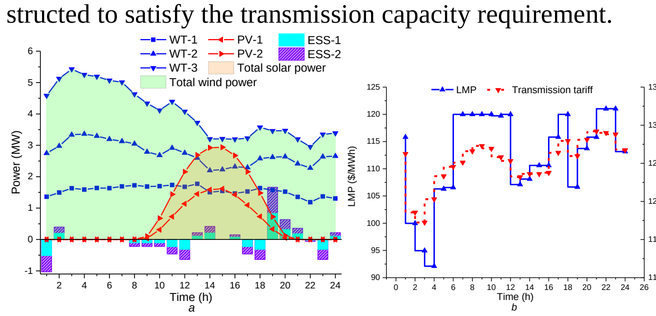

Fig. 5. Expected power curves and prices at node 4

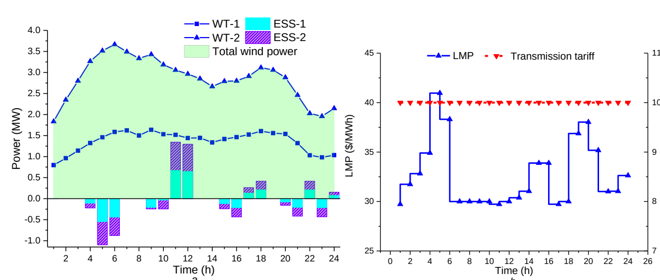

Fig. 6. Expected power curves and prices at node 5

Fig. 5 (a) and Fig. 6 (a) show the expected power curves of the invested DERs at node 4 and 5. Fig. 5 (b) and Fig. 6 (b) show the expected LMPs and transmission prices at node 4 and 5. From the results, the wind and solar power are fully accommodated in the operation simulation because the operational costs of WTs and PVs are 0. Driven by LMPs and transmission prices, the ESSs charge during valley hours and discharge during peak hours. By means of arbitrage, the ESSs can effectively reduce consumers' costs by shifting loads.

2) Comparisons Between Different Scenarios

The planning strategies for DERs at node 4 and 5 in three scenarios are compared in TABLE VI.

TABLE V
OPTIMAL PLANNING STRATEGIES FOR DERS IN THREE SCENARIOS

	S1		S2		S3	
	4	5	4	5	4	5
Planning strategies	No DER	No DER	3 WTs 2 PVs 2 ESSs	2 ESSs	3 WTs 2 PVs 2 ESSs	2 WTs 2 ESSs
Investment (million $)	0	0	1.88	0.02	1.88	1.02
Energy cost (million $)	14.09	9.07	17.85	6.39	16.89	5.15
Transmission cost (million $)	2.07	1.81	1.86	1.81	1.82	1.52
Total cost (million $)	16.16	10.88	21.59	8.22	20.59	7.69

In S3, the transmission costs take 8.84% and 19.77 % of the total costs at node 4 and 5, respectively. Therefore, transmission cost is an important factor in the planning for DERs. Comparing the results in S3 with those in S1, the equilibrium between the consumers at node 4 and 5 can be explained as follows: Firstly, the consumers at node 5 find it beneficial to invest in DERs. After investing in DERs at node 5, the consumers at node 4 will find an increase in his/her total costs because of the change in LMPs and transmission prices caused by the investments at node 5. Then the consumers at node 4 are economically driven to invest in DERs to reduce the electricity costs. The iterations continue until the equilibrium is achieved.

Comparing the results in S3 with those in S2, one can observe that more DERs are encouraged in S3 by considering TCA in the planning strategy. The transmission prices can further encourage the consumers to invest in DERs to reduce individual total costs. The planning strategies for TNs in three scenarios are compared in TABLE VI.

TABLE VI
OPTIMAL PLANNING STRATEGIES FOR TNS IN THREE SCENARIOS

Line No.	8	9	10	11	12	13	14	Investment (million $)
S1	0	1	0	1	1	1	1	53
S2	1	1	1	1	0	0	0	42
S3	1	1	1	0	0	0	0	32

From the results, because the invested DERs can satisfy some local load demands, only 3 transmission lines are needed constructing in S3. However, 5 and 4 lines are respectively needed for transmission capacities in S1 and S2. Therefore, by considering TCA in the planning strategy, more DERs will be invested in and the nodal net loads can be further reduced. Then less transmission lines are needed constructing and a large amount of centralized investment for TNs can be saved.

Note that line 3-5 (Line No. 11) can be saved in S3, compared with the results in S1 and S2. The maximum power flows on line 3-5 in three scenarios are shown in Fig. 7. As one can observe, the maximum power flows can be effectively limited below the transmission capacity 10 MW in S3. However, with no or less DERs, more transmission lines have to be constructed to satisfy the loads in S1 and S2. The maximum power flows reach 19.38 MW and 15.13 MW in S1 and S2, respectively.

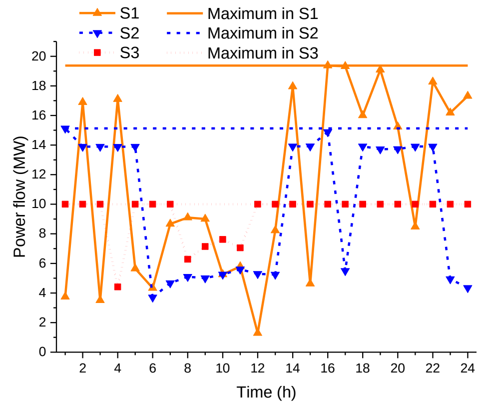

Fig. 7. Maximum power flows on line 3-5 in three scenarios.

Therefore, by considering TCA in the planning strategy, i) more DERs are encouraged to be invested in, which boosts the development of distributed energy at the demand side; ii) the consumers can further reduce the total costs and maximize individual revenues; iii) more importantly, a large amount of centralized investment for TNs can be saved for the power system. The net load demands can be further reduced and the transmission congestion can be alleviated, which effectively defers the transmission expansion and saves the planning costs.

B. IEEE 118-Bus System

The IEEE 118-bus system is used to further validate the effectiveness of the proposed model. Five nodes and ten candidate transmission lines are selected for illustration. The consumers at node 2, 13, 14, 16 and 117 are making investments for DERs. Each consumer has an annualized budget $2,600,000 for candidate DERs, including 5 WTs, 4 PVs and 3 ESSs. The parameters of candidate transmission lines are shown in TABLE VII.

TABLE VII
PARAMETERS OF CANDIDATE TRANSMISSION LINES IN IEEE 118-BUS SYSTEM

Line No.	From	To	Reactance (p.u.)	$P^{LN,\max}$ (MW)	Investment (million $)
1	2	12	0.062	10	10
2	1	2	0.100	10	10
3	13	15	0.244	10	10
4	11	13	0.073	10	10
5	14	15	0.195	10	10
6	12	14	0.071	10	10
7	16	17	0.180	10	10
8	12	16	0.083	10	10
9	12	117	0.140	10	10
10	12	117	0.140	10	10

To maximize the annualized revenues, the consumers at different nodes will strategically plan and operate DERs. The planning strategies for DERs at five nodes in S2 and S3 are compared in TABLE VIII. In S3, it takes 14 iterations and 593.60s to reach the equilibrium. Note that no DERs are planned in S1. As one can observe, by considering TCA in the planning model, the consumers will be economically driven to invest in more DERs. Compared with the results in S2, 3 more ESSs are to be invested at node 2 and 117, and 1 more WT is to be invested at node 14 in S3. The additional DERs can further influence the planning for TNs. TABLE IX shows the planning strategies for TNs in three scenarios.

TABLE VIII
OPTIMAL PLANNING STRATEGIES FOR DERS IN S2 AND S3

Node	S2			S3		
No.	WT	PV	ESS	WT	PV	ESS
2	4	2	0	4	2	3
13	4	3	3	4	3	3
14	3	3	3	4	3	3
16	4	3	3	4	3	3
117	3	4	0	3	4	3

TABLE IX
OPTIMAL PLANNING STRATEGIES FOR TNS IN THREE SCENARIOS

No.	1	2	3	4	5	6	7	8	9	10
S1	1	0	1	1	0	0	1	0	1	1
S2	0	0	1	1	0	0	1	0	1	0
S3	0	0	1	1	0	0	1	0	0	0

Fig. 8 compares the transmission expansion costs and consumers' total costs in three scenarios.

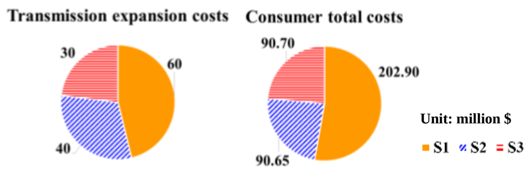

Fig. 8. Annualized transmission expansion costs and consumers' total costs in three scenarios.

Comparing the costs in S3 with those in S1, one can observe that by investing in DERs at the demand side, on one hand, the consumers can reduce the total costs and maximize individual revenues; on the other hand, the centralized investment for transmission expansion can be effectively saved. From the costs in S2 and S3, by considering TCA and transmission prices in the DER planning, the consumers can be further encouraged to invest in DERs. Then the centralized investment for TNs can be effectively reduced. The maximum power flows on line 12-117 in three scenarios are compared in Fig. 9.

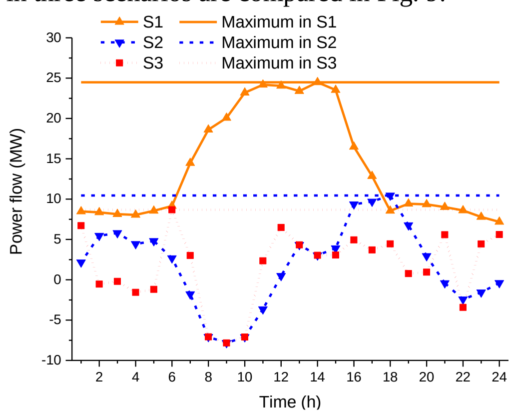

Fig. 9. Maximum power flows on line 12-117 in three scenarios.

As one can observe, without DER investments in S1, the maximum power flow on line 12-117 can reach 24.48 MW, which requires 2 candidate lines from node 12 to 117. In S2, 3 WTs and 4 PVs are invested and the maximum power flow on line 12-117 can be reduced to 10.45 MW, which only requires 1 candidate line 12-117. By considering TCA in the planning of DERs, 3 more ESSs are invested in S3 compared with the results in S2. Then the maximum power flow on line 12-117 can be further reduced to 8.68 MW. Thus, the maximum power flow can be effectively reduced, thereby deferring the transmission expansion planning.

VI. CONCLUSION

In this paper, a tri-level expansion planning model for TNs and DERs considering TCA is proposed, which can be formulated as a market equilibrium problem. On the first level, the consumers at different nodes make investments for DERs given the LMPs and nodal transmission prices. On the second level, based on the updated net loads after DER investments, TEP is optimized to satisfy transmission capacity requirements. On the third level, the LMPs and the transmission prices are updated by DCOPF and PFT approach. Due to the nonlinearity of the market equilibrium problem, an algorithm is presented to iteratively solve the tri-level model and a criterion is designed to acquire the optimal solution. In addition, scenario-based stochastic programming is adopted to address the uncertainties in renewable generations and load demands. Case studies based on a modified Garver-6 system and IEEE 118-bus system validate the proposed approach and model.

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