Transmission Network Planning under a price-based demand response program

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Abstract*— *Traditional transmission planning is primarily a trade off between congestions costs that are mainly driven by the supply side and transmission investments costs. Demand is treated as fixed and unresponsive to price signals from the energy market either in the short or long term. In this paper a price-based demand response program is incorporated into the transmission planning problem. Using an iterative procedure, transmission network capacities are proposed and based on these capacities nodal prices are calculated. The nodal prices then trigger demand response leading to new demand levels. The process is repeated until convergence. As is the case in practice the nodal prices as well as demand elasticity may change in the course of the year Therefore a multi-level load model associated with different elasticity is considered assuming the total energy consumption does not change beyond a pre-set amount although the demand level can alter in response to the price signal. In order to calculate the nodal price accurately, a transmission investment allocation method taking into account Use of System and Reliability Charges is also proposed. Since in practice transmission capacities come in standard discrete sizes the transmission planning process is formulated as a mixed-integer optimization problem. The proposed method is tested on a modified version of the IEEE 24 bus test system.

Index Terms—**Transmission Planning, Responsive demand, Transmission investment allocation, Mixed-integer optimization, Security constraint.**

I. INTRODUCTION

In a competitive real-time electricity market, a participant adapts its position in the market constantly driven by its costs, other participants' behaviors etc .These market dynamics should result in reductions in the end-use customers' energy costs. There are, however, still many consumers, mostly residential and commercial, that do not play an active role in the market. They have neither the opportunity nor option to change their consumption pattern based on real-time energy price variations because monthly bills are the only feedback they receive from the market although energy is traded in hourly intervals in the wholesale market. This inelastic consumers' response can simply cause emergence of market power phenomenon exerting unfair energy price on consumers [1]. This problem addresses a need for infrastructures and facilities able to send real-time price signal to consumers so that they can make energy use decisions on a daily or even hourly basis [2]. In order to meet this need, a move has recently been embarked on to replace conventional meters with so-called smart meters updating consumers on real-time energy price. Armed with smart meters, as studies and experience of practical applications show, end-use customers will actively respond to energy price changes in short intervals in such a way to either reduce the energy consumption or shift the energy usage time when electricity price is high [3] [4].

As one of the main drivers for power system's infrastructure expansion is load demand, a price-based responsive demand model rather than an inelastic demand model should be taken into account for generation or transmission expansion planning. There are still some issues about how a price-based demand response can be modeled because it has not yet been widely implemented in practice. In essence, it is very case sensitive depending on consumers' consumption culture in different areas [5] [6]. Moreover, price cannot be the only driver for demand response as consumers may have different reaction to price changes in different time of day or year. In other words to have a practical model a different elasticity should be assumed for different load levels.

In this work, a practical approach to transmission network planning assuming a price-based load response program is proposed. As demand response programs have just recently been launched, works investigating the effect of demand response on transmission planning are rare. Transmission planning is in essence a long-term planning problem, so incorporating price-based demand response needs a method to predict the future nodal prices as accurately as possible. In order to do that, a transmission investment allocation method is proposed so that Transmission Charges allocated to buses can be calculated at different load levels. An "N-1" security constrained Optimal Power Flow (OPF) analysis is deployed to find the Energy Price at a particular bus. Therefore nodal prices which comprise Transmission Charges and Energy Prices can be computed.

The proposed process is an iterative procedure that at the first stage transmission expansion proposal is made. Then nodal prices are calculated for the proposed network. A multi-level load model is considered along with a different elasticity for each load level so that as nodal prices are updated demands also alter accordingly. A least square method is applied to improve the resultant demands in such a way the total energy

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consumption changes are not allowed to go further than a preset specific amount which here is a percentage of original total energy consumption.

The remainder of the paper is organized as follows. In next section, the methodology, modeling and formulations through three sub-sections are presented. In Section III the method is implemented on the IEEE 24 bus test system, and finally in section IV some concluding remarks are made.

II. METHODOLOGY

An iterative process is proposed for transmission expansion planning assuming demand can respond to price changes. For any iteration, mixed-integer optimization is applied to propose the transmission expansion capacities. Then, for the proposed transmission network, nodal prices reflecting both generation costs and transmission costs are calculated. Considering the nodal prices as well as the demand response model, loads at all buses are updated in response to the new nodal prices. The whole procedure is repeated until a similar transmission capacity is proposed at the two consecutive iterations. Dash Xpress is used to solve the mixed-integer optimization problem. The different sections of the procedure are elaborated below.

A. Transmission planning formulation

A DC based power flow model is applied as this model has been successfully used to solve Transmission Network Problem (TNP) [7][8][9][10]. The main aim of TNP is to propose the best scenario of transmission expansion which minimizes the sum of transmission investment costs and generator operating costs in a given network for a horizon year. Furthermore, the optimum solution should be feasible for both intact and contingent networks. In other words, Kirchhoff's circuit laws should be respected, as should operating limits on system components. In practice, due to the lumpy nature of transmission investment, only particular capacities can be assumed for candidate lines, so discrete variables are incorporated into the TNP turning the problem into a mixed-integer optimization problem.

The objective function can therefore be expressed as follows:

$$\underset{G_i^j,\,\overline{P}_{\max i}}{Minimize}:\sum_{j=1}^{Np} D_j.\sum_{i=1}^{Ng} C_i.G_i^j+\sum_{i=1}^{\overline{N_l}} T_{ci}.l_i.\overline{P}_{\max i} \qquad (1)$$

In (1) the first term represents generation cost and the second term represents the transmission investment cost Notations in (1) are defined as follows:

D_j	Duration of the load level j (hour)
C_i	Incremental cost of generator i (€/MWh)
G_i^j	Power generated by generator i at load level j (MW)
T_{ci}	Annuitized investment cost of line i (€/km.MW.year)
l_i	Length of transmission line i (km)
$\overline{P}_{\max i}$	Capacity of candidate transmission line i (MW)
$\overline{N_l}$	Number of candidate transmission lines
N_p	Number of load levels
N_g	Number of generators

If a set S_i containing N_i different credible capacities for candidate line i is considered then the capacity of candidate line i is calculated by (3).

$$S_i=\left\{\overline{P_{i1}^n},\overline{P_{i2}^n},\ldots,\overline{P_{ik}^n},\ldots\right\} \qquad i=1,\ldots,\overline{Nl} \qquad (2)$$

$$\overline{P}_{\max i}=\sum_{k=1}^{N_i} x_{ik}.\overline{P_{ik}^n} \qquad i=1,\ldots,\overline{Nl} \qquad (3)$$

In (3) x_{ik} is a binary decision variable, and $\overline{P_{ik}^n}$ is kth credible capacity of the set S_i. As only one out of N_i members of S_i must be chosen the equality constraint (4) is added to the problem.

$$X_i=\sum_{k=1}^{N_i} x_{ik}\le 1 \qquad i=1,\ldots,\overline{Nl} \qquad (4)$$

It should be noted that the resultant X_i can be either 0 or 1.

Also, at each load level j the objective function is subject to Kirchhoff's laws governing the network. Kirchhoff's Current Law (KCL) is introduced to the problem as mathematically expressed by (5).

$$\sum_{\forall i\in N_{gk}} G_i^j+\sum_{\forall i\in N_{lk}} P_i^j-L_k^j=0 \qquad k=1,\ldots,N_b \qquad (5)$$

Where

P_i^j	Power flowing in transmission line i at load level j (MW)
L_k^j	Load demand at bus k for load level j (MW)
N_{gk}	Set of generators connected to bus k
N_{lk}	Set of lines connected to bus k
N_b	Number of buses

Furthermore, Kirchhoff's Voltage Law (KVL) should be respected. Different approaches, however, are taken into account to formulate KVL equations. For existing lines, in the p.u. system, KVL is expressed by equality constraint (6), whereas for candidate lines a disjunctive form with two inequality constraints given by (7) and (8) is constructed [7].

$$P_i^j-\frac{\left(\theta_k^j-\theta_l^j\right)}{X_{im}}=0 \qquad i=1,\ldots,N_l \qquad (6)$$

$$P_i^j-\frac{\left(\theta_k^j-\theta_l^j\right)}{X_{im}}\le M_k.(1-X_i) \qquad i=1,\ldots,\overline{N_l} \qquad (7)$$

$$P_i^j - \frac{\left(\theta_k^j - \theta_l^j\right)}{X_{im}} \geq M_k.(X_i - 1) \qquad i = 1,...,\overline{N_l} \qquad (8)$$

Where M_k is a very large number, also

N_l Number of existing transmission lines

θ_k^j Voltage angle of bus k (radian)

X_{im} Reactance of transmission line i (p.u.)

Limits on power system components including generation upper and lower bounds as well as maximum line capacities are expressed by (9) to (11).

$$G_{\min i} \leq G_i^j \leq G_{\max i} \qquad i = 1,...,N_g \qquad (9)$$

$$-P_{\max i} \leq P_i^j \leq P_{\max i} \qquad i = 1,...,N_l \qquad (10)$$

$$-\overline{P}_{\max i} \leq P_i^j \leq \overline{P}_{\max i} \qquad i = 1,...,\overline{N_l} \qquad (11)$$

The above problem is solved at different demand levels to reflect the temporal variations in demand and generation. (10) and (11) shows that the maximum capacities of transmission lines ($P_{\max i}$ and $\overline{P}_{\max i}$) should have the same value at all load levels. Regarding the above formulations G_i^j, x_{ik}, P_i^j and θ_k^j are decision variables.

Transmission network should be robust against any possible line outage. This robustness is usually guaranteed by introducing the so-called "N-1" criterion to the TNP problem [11]. For contingent networks, as for intact network, KCL and KVL are respected along with power flow limits. Due to generators' ramp rate limits, however, the power output of generators cannot be changed significantly once a line outage occurs. Therefore, in this study, generator outputs are assumed to be unchanged following a contingency in the network, so the KCL at each bus can be written as (12).

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}, i \neq c} P_i^{j(c)} - L_k^j = 0 \qquad k = 1,...,N_b \qquad (12)$$

Where c denotes a contingent network.

Similar to the intact network, KVL for existing and candidate lines can mathematically be expressed by (13) to (15).

$$P_i^{j(c)} - \frac{\left(\theta_k^{j(c)} - \theta_l^{j(c)}\right)}{X_{im}} = 0 \qquad i = 1,...,N_l \qquad (13)$$

$$P_i^{j(c)} - \frac{\left(\theta_k^{j(c)} - \theta_l^{j(c)}\right)}{X_{im}} \leq M_k.(1 - X_i) \qquad i = 1,...,\overline{N_l} \qquad (14)$$

$$P_i^{j(c)} - \frac{\left(\theta_k^{j(c)} - \theta_l^{j(c)}\right)}{X_{im}} \geq M_k.(X_i - 1) \qquad i = 1,...,\overline{N_l} \qquad (15)$$

B. Nodal Price Calculation

The nodal price at a particular bus is mainly made of two major components. The first component is the cost of serving the next MW at that particular bus which in this work is called Energy Price. In an OPF analysis, the Lagrangian multiplier of power flow balance equality constraint at a bus represents the Energy Price [12]. As loads change during the year, Energy Prices alter accordingly. In order to calculate the Energy Prices variations, in this study a multi-level load demand model reflecting annual load variations is considered. From this point onwards the Energy Price at bus k for load level j is marked as EP_k^j.

The second component of nodal price is the nodal share in transmission investment. There are still many issues about methods proposing a fair allocation of transmission investment. In this paper a method, mainly inspired by [13][14], is introduced for assigning the transmission embedded cost to loads as well as generators regarding their contribution to network assets usage in normal and contingency conditions.

As mentioned before, loads alter in the course of the year, so accordingly the contribution of loads to use of network also changes. Hence, as proposed in this work, loads or generators incur different network charges at different load levels. Transmission charge for a bus at a particular load level consists of two parts. The first part, the Usage Charge, is the charge due to use of network in normal condition, the second part, Reliability Charge, is the charge levied to recover the extra network capacity cost to keep supplying the load following a line outage.

The Usage Expense of transmission line i associated with intact network condition at load level j is formulated as follows (16).

$$UE_i^j = \frac{UF_i^j}{\sum_{k=1}^{Np} UF_i^j}.K_i.T_{ci}.l_i.\overline{\overline{P}}_{\max i} \qquad (16)$$

Where

$$UF_i^j = \frac{\left|P_i^j\right|}{\overline{\overline{P}}_{\max i}} \qquad (17)$$

$$K_i = Max(UF_i^1, UF_i^2, ..., UF_i^{Np}) \qquad (18)$$

$\overline{\overline{P}}_{\max i}$ is the capacity of branch i which is either an existing line or proposed line by the transmission planning problem described in section II.A.

In order to allocate the Usage Expense of line i, a normalized sensitivity matrix is used. For a given network, a sensitivity matrix A showing the relation between the powers flowing in transmission lines and powers injected to buses can be calculated [14], as shown by (19).

$$P_i^j = \sum_{k=1}^{Nb} A_{k,i}.\left(G_k^j - L_k^j\right) \qquad (19)$$

$A_{k,i}$ is an element of the sensitivity matrix which relates the power flow of line i to the power injection at bus k.

The normalized sensitivity matrix is expressed with (20).

$$NA_{k,i} = \frac{\left|A_{k,i}\right|}{\sum_{i=1}^{Nb} A_{k,i}} \tag{20}$$

The network usage charge allocated to bus k at load level j is shown in (21).

$$UC_k^j = \sum_{i=1}^{Nl+\overline{Nl}} NA_{k,i}.UE_i^j \tag{21}$$

The remnant expense associated with transmission line i is called Reliability Expense and is mathematically expressed by (22).

$$RE_i^j = T_{ci}.l_i.\overline{\overline{P}}_{\max i} - UE_i^j \tag{22}$$

It should be noticed that the total cost of a line is made of Reliability Expense and Usage Expense.

Reliability Expense, like Usage Expense, should also be allocated to buses. Outage factor showing the effect of tripping line c on line i at load level j is formulated as follows.

$$OF_{i,c}^j = \begin{cases} P_i^{j(c)} - P_i^j & if\ P_i^{j(c)} \geq P_i^j \\ 0 & else \end{cases} \tag{23}$$

(19) and (23) are used to produce the Bus Reliability Factor which represents the effect of injection at bus k on reliability of line i.

$$BRF_{k,i}^j = \sum_{c=1}^{Nc} OF_{i,c}^j.A_{k,c} \tag{24}$$

(25) shows the normalized Bus Reliability Factor

$$NBRF_{k,i}^j = \frac{BRF_{k,i}^j}{\sum_{j=1}^{Np}\sum_{k=1}^{Nb} BRF_{k,i}^j} \tag{25}$$

Also (26) shows the network Reliability Charge allocated to bus k at load level j.

$$RC_k^j = \sum_{i=1}^{Nl+\overline{Nl}} NBRF_{k,i}^j.RE_i^j \tag{26}$$

Transmission network users including generators and loads at bus k should pay both for Reliability Charge and Usage Charge, so the total charge at load level j can be expressed by (27).

$$TC_k^j = RC_k^j + UC_k^j \tag{27}$$

The total network charge should be translated to a cost per kilowatt hour incurred by loads and generators at bus k as presented by (28), (29) respectively.

$$LTC_k^j = \frac{TC_k^j.\dfrac{L_k^j}{L_k^j + G_k^j}}{L_k^j.D_j} \tag{28}$$

$$GTC_k^j = \frac{TC_k^j.\dfrac{G_k^j}{L_k^j + G_k^j}}{G_k^j.D_j} \tag{29}$$

Therefore the ultimate nodal price for a load at bus k is expressed by (30).

$$LNP_k^j = LTC_k^j + NP_k^j \tag{30}$$

C. Demand Response Modeling

The demand response model depends on the type of demand response program. In general, responsive demands may be categorized into two main groups namely (i) Incentive-Based Programs and (ii) Price-Based Program [15]. In an incentive-based program consumers are paid providing they reduce their consumption voluntarily or participate in a controlled load curtailment program when the network faces a critical condition or at peak load times. In a price-based demand response program, however, consumers receive a real-time energy price signal based on which they manage their consumption to reduce the total energy consumption costs. In this work a price-based demand response model is assumed so that in different load levels in the course of the year, the demands either increase or decrease following the change in the nodal prices. The amount of change in demand relies upon the change in price as well as an elasticity factor. Elasticity literally is the slope of demand vs. price curve. Due to the nonlinear nature of this curve the elasticity varies as price changes [16]. In order to circumvent this problematic nonlinearity issue, different elasticity factors each of which is associated with specific load level are taken into account. With this assumption, if the nodal price at bus k at load level j changes the new load demand is calculated by (31).

$$L_k^j = L_{k(orginial)}^j + E_k^j.(LNP_k^j - LNP_{k(original)}^j).\frac{L_{k(orginial)}^j}{LNP_{k(original)}^j} \tag{31}$$

$L_{k(orginial)}^j$ Original demand at bus k at load level j

$LNP_{k(original)}^j$ Original price at bus k at load level j

E_k^j Elasticity for bus k at load level j

Price-based demand response can be one of the effective ways for peak load shifting and flattening the aggregated load curve. The key question is whether customers have the opportunity to make up the curtailed demand at another time when the price is low. It is also possible that the total energy consumption goes higher depending on the energy recovery process. In this work, it is assumed that the change in total energy consumption at each bus does not go either over or under a particular amount. In order to keep the total energy consumption within the specific range a least square method which is shown by (32) is deployed to amend the load demands calculated by (31).

$$Minimize : \sum_{j=1}^{Np} (L_{k(improved)}^j - L_k^j)^2 \qquad (32)$$

Subject to:

$$\sum_{j=1}^{Np} L_{k(improved)}^j . D_j \leq (1+\alpha). \sum_{j=1}^{Np} L_{k(original)}^j . D_j \qquad (33)$$

$$\sum_{j=1}^{Np} L_{k(improved)}^j . D_j \geq (1-\alpha). \sum_{j=1}^{Np} L_{k(original)}^j . D_j \qquad (34)$$

$L_{k(improved)}^j$ is the improved load demand at bus k at load level j so that the total energy consumption is not $\alpha\%$ more than or $\alpha\%$ less than the original energy consumption as dictated by inequality constraints (33) and (34). In this work, at most 5% deviation from original total energy consumption is allowed.

The whole process for transmission planning assuming price-based responsive demands is shown in Fig. 1. The process stops once the transmission capacities at two successive iterations are identical.

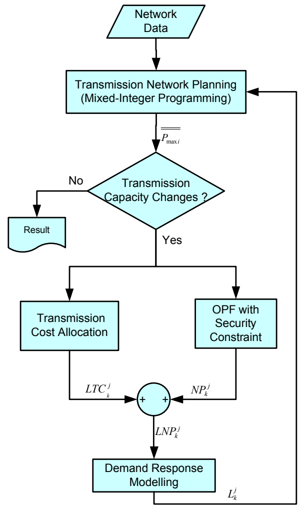

Fig.1 The procedure of the proposed method

III. CASE STUDY

The proposed transmission planning method under demand response program is tested on IEEE 24 bus network [17] which is slightly modified. All relevant data for this case study are given in Appendix A.

Credible capacities for branch numbers 7, 14, 15, 16, 17, all of which are transformers, are assumed to be either 200 or 300 MW. The rest of candidate branches which are overhead lines can be allocated a capacity of 200, 250, 300, 350 or 400 MW. Also, four load levels each of which has a specific elasticity factor are taken into account. An annuitized transmission investment cost of 11.79 €/km.MW.year which has been calculated based on National Grid Report [18] and the currency exchange rate of £1.00= €1.23 is used.

Based on the given data, after five iterations the program converges to transmission capacities which are shown in Fig. 2. The optimum transmission capacities assuming inelastic demand are also given in Fig. 2. As shown, with a responsive demand the total transmission capacity is 650 MW less than that the transmission capacity required to supply inelastic loads. This represents a 12.55% reduction in total transmission investment cost.

As depicted in Fig. 3 the final load demand pattern is also different from the original demand. Consumers simply shift their consumptions from peak load time to the periods when the energy price is lower, but there is just a slight change of 0.003% in original total energy consumption. The aggregated demand at load level one shows a reduction of 205.9 MW whereas there are increments of 68.7 MW and 69.8 MW at load level two and level four, respectively.

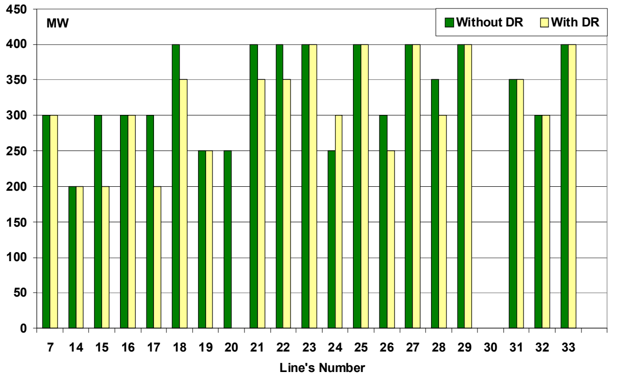

Fig. 2 Optimum transmission capacities for elastic and inelastic demand

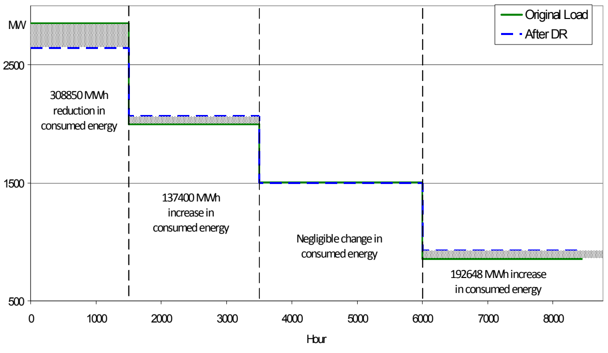

Fig. 3 Original load pattern and load pattern after response of consumers

Table I gives Transmission Charges incurred by each load in the network. Transmission Charges are comparatively lower than Energy Prices which are shown in Table II. For this case study, the resultant Energy Prices at all buses are identical. As results demonstrate, the major part of the total cost paid by loads is driven by Energy Price. Although this observation might be predictable, transmission charges are taken into account in this work so as to have the correct nodal prices seen by customers.

TABLE I
ALLOCATED TRANSMISSION CHARGES TO LOADS (€/MWH)

Bus #	Load Level				Bus #	Load Level			
	(1)	(2)	(3)	(4)		(1)	(2)	(3)	(4)
1	0.40	0.32	0.31	0.31	13	0.02	0.02	0.01	0.00
2	0.51	0.34	0.31	0.39	14	0.06	0.09	0.05	0.03
3	0.18	0.35	0.17	0.10	15	0.04	0.06	0.03	0.02
4	0.75	0.51	0.49	1.34	16	0.11	0.15	0.08	0.05
5	0.73	0.74	1.12	0.64	17	0.00	0.00	0.00	0.00
6	0.25	0.31	0.09	0.26	18	0.05	0.06	0.04	0.05
7	0.05	0.14	0.09	0.03	19	0.13	0.16	0.08	0.05
8	0.07	0.21	0.13	0.05	20	0.19	0.21	0.10	0.06
9	0.10	0.11	0.10	0.13	21	0	0	0	0
10	0.07	0.16	0.12	0.11	22	0	0	0	0
11	0	0	0	0	23	0	0	0	0
12	0	0	0	0	24	0	0	0	0

TABLE II
ENERGY PRICES AT DIFFERENT LOAD LEVELS (FOR THIS CASE STUDY, THE ENERGY PRICES AT ALL BUSES ARE IDENTICAL)

	Load Level			
	(1)	(2)	(3)	(4)
Energy Price (€/MWh)	55.19	50.40	45.20	35

IV. CONCLUSION

An iterative method for transmission network planning considering price-based demand response has been proposed in this paper. Due to the fact that consumers may react differently to price variations at different times of the day or even the year, a multi-level load model with different elasticity for each load level has been taken into account. Although consumers tend to shift their electricity usage to the times when the energy price is low, it is very unlikely that the total energy consumption will change dramatically. Therefore a constraint has been added to the problem so that the total change in energy consumption at a particular bus is kept within pre-set bounds as demand changes based on price and elasticity.

Also a transmission investment allocation method has been introduced in order to project the nodal prices in a horizon year as accurately as possible.

The transmission planning problem has been formulated in the form of a mixed-integer optimization problem because in practice only a discrete set candidate transmission lines or transformers can be used.

The model introduced in this paper has clearly demonstrated consumers' tendency to shift their consumption to reduce their energy cost. This action firstly flattens the annul load curve and secondly defers the need for more transmission capacity. Therefore the proposed approach can be a useful hedge against over-investments in the transmission network. For the test case simulated on the IEEE 24 bus test system the proposed method defers installation of 650 MW of transmission capacity if elastic demand is assumed.

APPENDIX A

Table A.I shows the network specification including existing and candidate branches in the modified IEEE 24 bus test system. Candidate branches are shadowed Generation cost and output limits are given in Table A.II. The data required for demand response modeling including original loads, original prices, elasticity and load durations are given in Table A.III.

TABLE A.I
TRANSMISSION BRANCH DATA FOR 24 BUS NETWORK

Branch #	Sending Bus	Receiving Bus	X(p.u.)**	Capacity (MW)	Length (Km)
1	1	2	0.0139	100	3
2	1	3	0.2112	100	55
3	1	5	0.0845	100	22
4	2	4	0.1267	100	33
5	2	6	0.192	150	50
6	3	9	0.119	150	31
7*	3	24	0.0839	---	50
8	4	9	0.1037	100	27
9	5	10	0.0883	100	23
10	6	10	0.0605	150	16
11	7	8	0.0614	150	16
12	8	9	0.1651	300	43
13	8	10	0.1651	300	43
14*	9	11	0.0839	---	50
15*	9	12	0.0839	---	50
16*	10	11	0.0839	---	50
17*	10	12	0.0839	---	50
18	11	13	0.0476	---	33
19	11	14	0.0418	---	29
20	12	13	0.0476	---	33
21	12	23	0.0966	---	67
22	13	23	0.0865	---	60
23	14	16	0.0389	---	27
24	15	16	0.0173	---	12
25	15	21	0.049	---	34
26	15	24	0.0519	---	36
27	16	17	0.0259	---	18
28	16	19	0.0231	---	16
29	17	18	0.0144	---	10
30	17	22	0.1053	---	73
31	18	21	0.0259	---	18
32	19	20	0.0396	---	27.5
33	20	23	0.0216	---	15
34	21	22	0.0678	---	47

*Transformer

** The base power is 100 MW

TABLE A.II
GENERATION INFORMATION FOR THE 24 BUS NETWORK

Gen. #	Bus #	Pmax (MW)	Pmin (MW)	Generation price (€/MWh)
1	1	40	0	50
2	1	152	0	45.2
3	2	40	0	50
4	2	152	0	45.2
5	7	150	0	51.2
6	13	591	0	51.2
7	15	60	0	50
8	15	155	0	40
9	16	155	0	40
10	18	400	0	35
11	21	400	0	35
12	22	300	0	51.2
13	23	310	0	40
14	23	350	0	45.2

TABLE A.III
LOAD DATA FOR 24 BUS NETWORK

		Load Level (MW)			
		(1)	(2)	(3)	(4)
Bus #	1	108	75.6	57.02	32.4
	2	97	67.9	51.22	29.1
	3	180	126	95.04	54
	4	74	51.8	39.07	22.2
	5	71	49.7	37.49	21.3
	6	136	95.2	71.81	40.8
	7	125	87.5	66	37.5
	8	171	119.7	90.29	51.3
	9	175	122.5	92.4	52.5
	10	195	136.5	103	58.5
	11	0	0	0	0
	12	0	0	0	0
	13	265	185.5	139.9	79.5
	14	194	135.8	102.4	58.2
	15	317	221.9	167.4	95.1
	16	100	70	52.8	30
	17	0	0	0	0
	18	333	233.1	175.8	99.9
	19	181	126.7	95.57	54.3
	20	128	89.6	67.58	38.4
	21	0	0	0	0
	22	0	0	0	0
	23	0	0	0	0
	24	0	0	0	0
Duration (hours)		1500	2000	2500	2760
Elasticity		-1.5	-1.0	-0.8	-0.5
Original Price (€/MWh)		49	47	45	42

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