Optimal Distribution Service Pricing for Investment Planning

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Abstract-- **Distribution network development planning is a complex task due to the size of a typical distribution network, the interconnectivity of its elements and the presence of various uncertainties. This planning process becomes even more complicated due to the constant pressure to reduce distribution network capacity reserve, operation and maintenance cost, and to postpone the capital investments as far as possible. Recent technological and organizational changes in the electric industry sector have had an influence on the operations and planning objectives of distribution network systems. New technologies and customer demand types require new paradigms of distribution network planning and operations. A corresponding model in support of these new paradigms should not include only the load forecast, but economic analysis, risk assessment and the impact of the new technologies. In this paper, we propose a model for distribution development planning with direct load control, distributed generators and optimal distribution capacity expansion.**

Index Terms-- **Development Planning, Direct Load Control, Distributed Generation, Electrical Distribution Network, Electric Power Restructuring, Optimal Network**

I. Introduction

The recent changes in the electric industry [1] have had an influence on the operations and planning of distribution network systems. New technologies and types of customer demand [2-4] require a new model of distribution network planning. We already showed [5] what impact elastic demand can have on distribution planning. Direct load control is similar, but in this case distribution utility should know in advance what price customers will pay for delivery.

The organization of this paper is as follows. Section II describes the direct load control and impact of distributed generation. Both of them could be used to postpone investment into distribution network expansion. A model of distribution development planning based on the direct load control, distributed generation and optimal distribution capacity expansion is proposed in Section III. This model is useful for utilities that supply price-responsive customer demands. At least in principle, such customers could enable utilities to postpone their investments and gain larger profits. These customers would contribute to a decreasing peak load and, therefore, to reduced requirements for new capacity. The proposed model is applied to a simple distribution network in the later part of this paper. The given solution is optimal with respect to the both optimal network configuration and optimal time investment.

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II. Background

Traditionally, electric utilities have had an obligation to serve their “native” customers according to the state-regulated electricity tariffs [6]. During the last decade of the 20th century, developing countries were faced with the serious problem of how to satisfy future demand. Load demand was increasing rapidly, power system operation was ineffective and tariff policy did not satisfy customer needs [7]. These were the first signals that something should be changed in the electrical industry.

The planning process becomes more complicated due to the constant pressure to reduce the distribution network capacity reserve, the operation and maintenance cost (O&M), and to postpone the capital investments as far as possible. Decreasing O&M costs and postponing investments are problems not unique to the de-regulated distribution utilities. However, these problems are emphasized by the fact that utilities face, under so-called “open access”, increased uncertainties of customer location, quantity, shape of the daily diagram of consumption and load quality in the network.

Distribution utility that has problems with satisfying the peak-load has a choice to solve the lack of capacity in three different ways. The first way is to build new capacities. The second way is to reduce the maximal load [8]. The third possibility is to allow connection of distributed generators.

A. Direct load control

Direct load control is a type of demand response. A customer load is centrally controlled through a series of communication devices and switches. Direct load control is focused on reducing energy usage during critical periods, such as during peak demand or failures [9-10].

Direct load control is being applied to the consumers whose devices can be turned on or off or programmed in relatively short time. Things that are the most commonly controlled are: air conditioners, water heaters, pool-pumps and electric heaters that have stocking capability.

This program for load management, although disturbing the comfort of the consumers, has a very large number of participants. The consumers get a suitable compensation for every load reduction, for the season when the reduction is to be expected or for the whole year.

A distribution utility can postpone investment if they offer similar program for electricity distribution. Signing the agreement customer agrees to allow utility to reduce consumption in situation which is critical for the utility or for distribution network and customer will be compensated for this reduction. By accepting the contract, both the utility and customer take a risk of price change. The price that is given by agreement should be the average price that is acceptable for both parties. In the case when distribution price increases, customer will have benefit, while if the distribution price decreases utility will be in better position.

B. Distributed Generation

The second novel problem facing the distribution planner is the consideration of distributed generation. Distributed generation is potentially very useful for increasing the marginal capacity of the distribution network and increasing supply reliability.

Distributed generators (DG) are small power generators, usually in the range from 15 kW to 10 MW, which are connected within the distribution system. These are independent sources of energy that can provide sufficient quantity of electricity to supply the households, commercial buildings and industry. They could be “substitution” for distribution network expansion. There are two main reasons for introducing distributed generators:

1. by introducing deregulation into power industry, wholesale electricity market has been created where everybody who owns the generator can participate;
2. global trend to reduce the pollution leads toward the use of the renewable sources of energy, which are closely related to the DG.

Distribution utilities very often receive requests from distributed generators for connection to distribution network. Distribution utilities should take advantage of this situation, but still they should be aware that distributed generators could create some serious problems, such as [11]:

- increased fault current due to the parallel connection with the system;
- cause an inaccurate measurement of fault currents;
- induce an opposite direction of current flows through the relay;
- bidirectional power flow in structures that were designed for radial unidirectional operation;
- potential separation of DG supplied mini-grids within a distribution network.

III. Problem formulation and Proposed Solution

Recent technological and organizational changes in the electric industry sector have had an influence on the operations and planning objectives of distribution network systems. New technologies and customer demand types require new paradigms of distribution network planning and operations. A corresponding model in support of these new paradigms should not include only the load forecast, but economic analysis, risk assessment and the impact of the new technologies.

Our suggested model for development planning is based on the concepts of optimal distribution capacity expansion [12], controllable demand, and distributed generation. The idea is that the optimal plan cannot be determined based on the load forecasts only but also on information about demand control and on information about possible installation of distributed generators. The proposed model gives an optimal solution that minimizes the sum of the total operating, maintenance and investment costs.

A. Model for Distribution Network Development Planning

A possible metrics for measuring the long-term performance of a utility can be expressed as a quadratic optimization problem subject to linear constraints, where the performance objective is (1).

$$
\begin{aligned}
\max_{P_l^t, P_d^t, x_i, b_i, r_i} \quad \Omega = \\
\sum_{t=1}^{NoP} \Bigg[\rho^{t-1} \cdot \Bigg(& \sum_{i=1}^{n} \left(N_i^t \cdot a_i^t + b_i^t \cdot P_{di}^t \right) \cdot T^t - \\
& \sum_{l=1}^{m} \Big(a_l^t \left(x_l^t + x'^t_l \right) + d_l^t \left(P_l^t + P'^t_l \right) + \\
& c_l^t \left(\left(P_l^t \right)^2 + \left(P'^t_l \right)^2 \right) \Big) \cdot l_l \cdot T^t - \\
& \sum_{l=1}^{m_{new}} C_{buiLine} \cdot b_l^t \cdot l_l \cdot P_l^{\max} - \\
& \sum_{l=1}^{m_{old}} C_{reiLine} \cdot r_l^t \cdot l_l \cdot \Delta P_l^{\max} \Bigg) \Bigg]
\end{aligned} \qquad (1)
$$

The first term in the objective function represents the charge that customers have agreed to pay by signing agreement with the distribution utility. This is the total income that the utility receives from the delivery of electric power. The second term is the utility’s cost of power delivery. The third term is the cost of building a new line, and the fourth term is the cost of replacement of an existing element.

The objective function does not contain a distributed generator installation or operation/maintenance cost because distribution utility does not own the distributed generators. The distributed generators are indirectly included into the optimization problem. They offer the possibility to overcome the limited distribution system capacities, and at the same time, they increase the reliability of the overall power system.

The terms in (1) are as follows:

NoP number of years over which the optimization is attempted;

n number of network nodes;

m total number of branches in the network

	($m = m_{old} + m_{new}$);
m_{old}	number of existing branches;
m_{new}	number of potential new branches;
N_i^t	number of customers at the node i ;
a_i^t , b_i^t	constant and time-varying terms, respectively, in annual price function that is paid by customer at node i at time period t ;
P_{di}^t	maximum annual power at node i at time period t ;
a_l^t	capital cost of power delivery;
d_l^t	variable cost of power delivery (linear part);
c_l^t	variable cost of power delivery (quadratic part);
P_l^t	power flow at the branch l at time period t ;
l_l	length of line l;
T^t	length of the time period;
x_l^t	integer variable which presents the status of the switch on the branch;
$C_{builLine}$	cost of building a new line;
b_l^t	integer variable that represents year when some line should be built (it has value 1 at the year when the new line is built and 0 otherwise);
r_l^t	integer variable that represents the year when some line should be reinforced (it has value 1 at the year when the existing line is replaced and 0 otherwise);
$C_{reiLine}$	cost of reinforcement of existing line, and
ρ	discount rate.

The solutions of the optimization problem are: the optimal power flow, maximal annual power, network topology, optimal location of distributed generators, and time of investments. The optimal power flow can have both directions - from the supply substation to the load or from the load to the supply substation. To avoid a negative sign of the optimization variables, a fictitious variable is introduced and marked with an apostrophe.

The optimization problem is subject to the following constraints:

1) Power balance:

$$\sum_{P_l^t, P_l^t{}' \in G_{\mathrm{in}}} \left(P_l^t + P_l^t{}'\right) - \sum_{P_l^t, P_l^t{}' \in G_{\mathrm{out}}} \left(P_l^t + P_l^t{}'\right) = P_{di}^t \qquad (2)$$

$$i = 1...n, \quad t = 1...NoP$$

where G_{in} − is a set of branches directed towards the node i, and G_{out} − is a set of branches which come out from the node i.

2) Maximum number of distributed generators in the network

$$\sum_{t=1}^{NoP} y_i^t = MaxDGNo \qquad i = 1...n \qquad (3)$$

As it was mentioned earlier the distributed generators are not included into objective function because the distribution utility does not own generation. To avoid situation where the optimal solution is the placement of distributed generators at each node, the number of distributed generators ($MaxDGNo$) is specified in advanced. The output of the proposed optimization model is the optimal location and size of the accepted number of DG.

3) Capacity constraints:

$$P_l^t - x_l^t \cdot P_l^{\max} - \Delta P_l^t \le 0 \qquad (4)$$

$$P_l^t{}' - x_l^t{}' \cdot P_l^{\max} - \Delta P_l^t{}' \le 0 \qquad (5)$$

$$l = 1...m_{old}, \quad t = 1...NoP$$

Power flow through the line l must be smaller then the sum of the maximum line power flow $P_l^{\max}$ and additional capacity ΔP_l^t . The value of x_l^t and $x_l^{'t}$ is calculated from this inequality. If power flow through branch l exists, x_l^t or $x_l^{'t}$ has value 1 but not both. Based on the value of x_l^t and $x_l^{'t}$, the constant part in the power delivery function ($a_l^t \cdot l_l \cdot (x_l^t + x_l^{'t})$) is included in the calculation just for the branches with nonzero power flow.

4) Limit on capacity increases:

$$\Delta P_l^t - x_l^t \cdot \Delta P_l^{\max} \le 0 \qquad (6)$$

$$\Delta P_l^t{}' - x_l^t{}' \cdot \Delta P_l^{\max} \le 0 \qquad (7)$$

$$l = 1...m_{old}, \quad t = 1...NoP$$

The capacity increase also must be limited. If the branch exists, $x_l^t = 1$ or $x_l^{'t} = 1$, additional capacity should exist.

5) Capacity of a new line:

$$P_l^t - x_l^t \cdot P_l^{\max} \le 0 \qquad (8)$$

$$P_l^t{}' - x_l^t{}' \cdot P_l^{\max} \le 0 \qquad (9)$$

$$l = 1...m_{new}, \quad t = 1...NoP$$

Final capacity of the new line is calculated as maximum capacity needed for all time periods of analysis: $P_l^{new} = \max_t \{P_l^t\}$.

6) Limit on the distributed generator capacity

$$P_{G_i}^t - \sum_{t=1}^{NoP} y_i^t \cdot P_{G_i}^{\max} \le 0 \qquad (10)$$

$$i = 1...MaxDGNo, \quad t = 1...NoP$$

Each DG operates between $P_G^{\max}$ and $P_G^{\min}$. If the distributed generator is placed in the distribution network it will remain connected until the end of planning period.

7) Reinforcement time:

Variables x_l^t and $x_l^{'t}$ carry information about the state of the switch and they can be changed from one time period to another. The decision variable r_l^t is 1 if an existing line l is reinforced during time period t and 0 for other time periods.

$$\Delta P_l^t - \sum_{t=1}^{NoP} r_l^t \cdot \Delta P_l^{\max} \leq 0 \tag{11}$$

$$\Delta P_l^{t\,'} - \sum_{t=1}^{NoP} r_l^t \cdot \Delta P_l^{\max} \leq 0 \tag{12}$$

$$l = 1 \ldots m_{old}\ , \quad t = 1 \ldots NoP$$

There is no variable $r_l^{t'}$ because it is not important if a line or its fictitious line is reinforced. In both cases, these would imply a reinforcement of the same branch.

8) The time of building a new line:

The decision variable b_l^t associated with the time of building a new line l in time period t is introduced. The reason is the same as in the case of reinforcement, i.e. keeping track of the line from a set of potential new lines which have been built or not.

$$P_l^t - \sum_{t=1}^{NoP} b_l^t \cdot P_l^{\max} \leq 0 \tag{13}$$

$$P_l^{t\,'} - \sum_{t=1}^{NoP} b_l^t \cdot P_l^{\max} \leq 0 \tag{14}$$

$$l = 1 \ldots m_{new}\ , \quad t = 1 \ldots NoP$$

9) Building/reinforcing information expansion

This constrain keeps information about building/reinforcing the lines over the time periods of analysis. Once the new line has been built, or the existing one has been reinforced, it will not be built or reinforced again. The decision variables r_l^t and b_l^t will have value equal to one only for year t when the line is reinforced/built and value equal to zero for all other years.

$$\sum_{t=1}^{NoP} r_l^t \leq 1 \qquad l = 1 \ldots m_{old} \tag{15}$$

$$\sum_{t=1}^{NoP} b_l^t \leq 1 \qquad l = 1 \ldots m_{new} \tag{16}$$

10) Radial network constraint:

$$\sum_{x_l, x_l' \in G_{in}} \left(x_l^t + x_l^{'t} \right) \leq 1 \qquad l = 1 \ldots n\ , \quad t = 1 \ldots NoP \tag{17}$$

This constraint expresses that there is only one supply path for each node in the network. The path is defined by set of switches x_l^t. State of a switch can be changed during time period t so the network topology during one time period can be different from the network topology in another time period.

11) Uniqueness constraint:

$$x_l^t + x_l^{'t} \leq 1 \qquad l = 1 \ldots m\ , \quad t = 1 \ldots NoP \tag{18}$$

There is no possibility for a branch and the corresponding fictitious branch to co-exist at the same time because it is not possible for a line power flow to go in both directions at the same time.

12) Demand control

$$P_{di}^{\min\ t} \leq P_{di}^t \leq k_i^t P_{di}^{\max\ t} \qquad i = 1 \ldots n\ , \quad t = 1 \ldots NoP \tag{19}$$

$$k_{\min} \leq k_i^t \leq k_{\max} \qquad i = 1 \ldots n\ , \quad t = 1 \ldots NoP \tag{20}$$

Parameter k_i^t is an integer variable, which determines by how much the demand could be reduced. It has value from 0 to 10, where $k_i^t = 0$ means that load could be disconnected and $k_i^t = 10$ means that demand must be completely satisfied.

B. *Example of the model application*

The developed model can be applied to both elastic and inelastic load demand. For inelastic demand inequality constraint (19) is changed to an equality constraint.

For simulation, commercial software TOMLAB [15] was used.

The above formula is illustrated on a test network shown in Fig. 1.

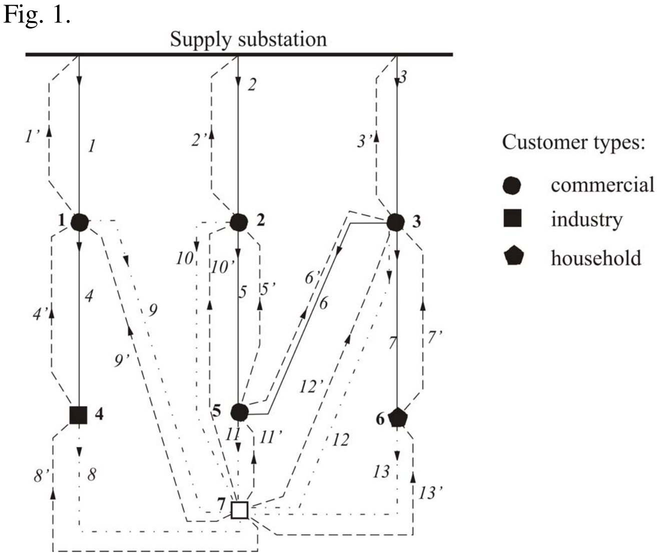

Fig. 1. The Test Network - Simple Distribution System

The chosen test network consists of 7 nodes and 13 branches. The existing branches are shown with full lines, while new lines are shown with dot-dash-dot lines. The corresponding fictitious branches are shown with dotted lines and they are marked with an apostrophe ('). Black nodes represent existing consumption, while the white node denotes the new load. There are 6 existing nodes and one new.

Branch characteristics are presented in Table I. Ind denotes the branch index; l1g and l2g denotes respectively the index of the node from the first and the second end of the branch; $P^{\max}$ denotes the maximum capacity of the branch; $\Delta P^{\max}$ is the maximum additional capacity of an existing branch.

The power consumption at the nodes is given in Table II. The planning period is chosen to be 10 years, with planning increment of 1 year. Ind stands for the node index; numbers from 1 to 10 denote years.

TABLE I
BRANCH CHARACTERISTICS

Ind	l1g	l2g	l (km)	$P^{\max}$ (p.u)	$\Delta P^{\max}$ (p.u)
1	0	1	1.0	20	5.0
2	0	2	1.0	14	5.0
3	0	3	1.0	10	5.0
4	1	4	2.0	10	5.0
5	2	5	1.5	20	5.0
6	3	5	3.0	10	5.0
7	3	6	2.3	20	5.0
8	4	7	2.0	20	0.0
9	1	7	5.0	20	0.0
10	2	7	4.3	20	0.0
11	5	7	1.0	20	0.0
12	3	7	3.5	20	0.0
13	6	7	2.0	20	0.0

The number of customers at each node is shown in Table III.

The price of the power delivery that is paid by households (h), industry (i) and commercial (c) is as in [13]:

- $p_h = (N_i^t \cdot 146\frac{\$}{year} + 109500\frac{\$}{MW \cdot year} \cdot P_D)$
- $p_i = 64800\frac{\$}{MW \cdot year} \cdot P_D$
- $p_c = (51 \cdot \frac{\$.}{year} + 87600\frac{\$}{MW \cdot year} \cdot P_D)$

TABLE II
NODE CONSUMPTION PER UNIT

Ind	1	2	3	4	5	6	7
1	5.2	7.5	4.9	9.3	0.08	0.08	0.0
2	5.4	7.5	5.0	9.3	0.08	0.08	0.0
3	6.0	7.5	5.1	9.3	0.08	0.08	0.0
4	6.5	7.5	5.2	9.3	0.08	0.08	0.0
5	8.2	7.5	5.5	9.3	0.08	0.08	5.6
6	8.7	7.5	5.6	9.3	0.08	0.08	5.8
7	9.2	7.5	5.8	9.3	0.08	0.08	6.2
8	9.8	7.5	6.0	9.3	0.08	0.08	7.0
9	10.5	7.5	6.2	9.6	0.08	0.08	9.0
10	12.9	7.5	6.8	10.2	0.08	0.08	14.7

TABLE III
THE NUMBER OF CUSTOMER AT NODE

Ind	1	2	3	4	5	6	7
1	100	125	100	001	150	003	0
2	100	125	100	001	150	003	0
3	100	125	100	001	150	003	0
4	120	125	110	001	150	003	0
5	120	125	110	001	150	003	100
6	120	125	110	001	150	003	100
7	150	125	110	001	150	003	100
8	150	125	110	001	150	003	120
9	180	125	115	001	200	003	250
10	250	125	115	001	200	003	250

The utility's cost of delivering 1 MW along 1 km per year is [14]:

$$p_{per\_year} = 4250\frac{\$}{km} + 206\frac{\$}{MWkm} \cdot P_l^t + 244\frac{\$.}{MW^2 km} \cdot (P_l^t)^2$$

The cost of building and reinforcing an existing line respectively is $46,000.00/MWkm and $100,000.00/MWkm [14]. The discount rate is 0.9.

Three cases are analyzed:

(a) Inelastic demand (minimum cost planning);
(b) Direct load control without distributed generators;
(c) Direct load control with distributed generators.

Load could be controlled between 70% up to 100% of its maximal value with 10% increment. The distributed generators are controllable between 0 and 10 p.u.

The given solution is shown in Fig. 2, Fig. 3 and Fig. 4. Optimal load flow is given in Table IV, Table V, and Table VI respectively.

It can be seen that in case (a) line 11 should be built in the 5th year to satisfy the new load, and lines 1, 2 and 4 should be reinforced in year 9, 6 and 10 respectively because load flow would exceed line capacity otherwise.

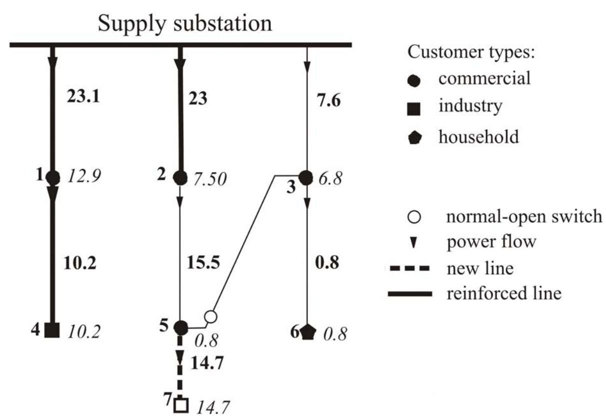

Fig. 2. Optimal Solution for 10 Years Planning Period– (a)

In case (b), the benefit has increased. The utility must reinforce line 2 in year 8 to satisfy load growth. Line 11 should be built to satisfy new consumption.

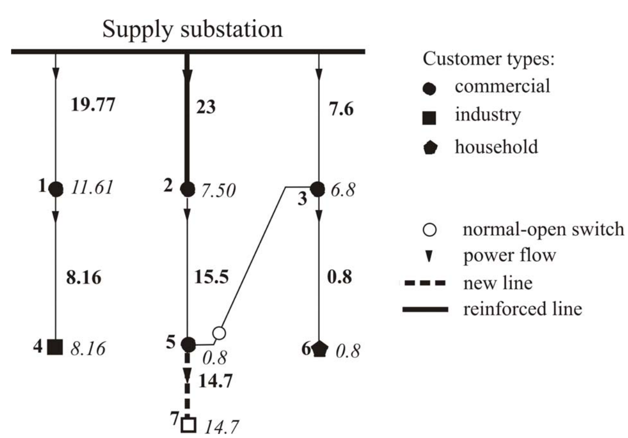

Fig. 3. Optimal Solution for 10 Years Planning Period – (b)

Solution (c) is the best solution for the distribution utility. Distributed generators are used to “increase” capacity of the distribution network. Their optimal location is at nodes 4 and 7. In this case, the utility can avoid any reinforcement in the system but still must build new line to satisfy new demand. Moreover, consumption was not decreased although direct load control was available.

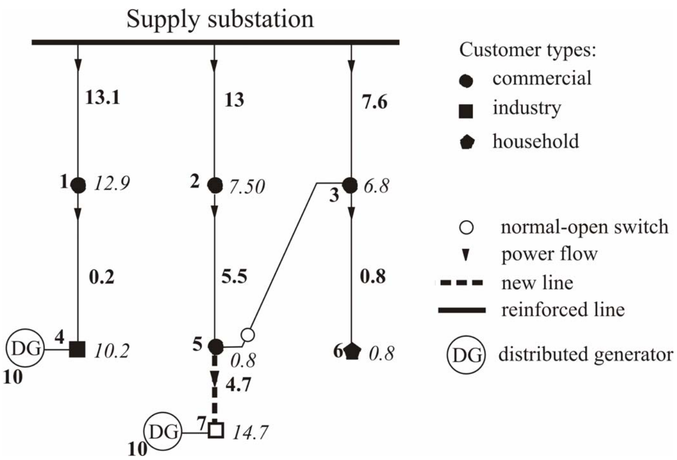

Fig. 4. Optimal Solution for 10 Years Planning Period - (c)

All solutions are optimal in terms of optimal network configuration and optimal time investments.

TABLE IV

OPTIMAL LOAD FLOW P.U. FOR 10 YEARS PERIOD – (A)

Ind	1	2	3	4	5	7	11
1	14.5	8.3	5.7	9.3	0.8	0.8	---
2	14.7	8.3	5.8	9.3	0.8	0.8	---
3	15.3	8.3	5.9	9.3	0.8	0.8	---
4	15.8	8.3	6	9.3	0.8	0.8	---
5	17.5	13.9	6.3	9.3	6.4	0.8	**5.6**
6	18	**14.1**	6.4	9.3	6.6	0.8	**5.8**
7	18.5	**14.5**	6.6	9.3	7	0.8	**6.2**
8	19.1	**15.3**	6.8	9.3	7.8	0.8	**7**
9	**20.1**	**17.3**	7	9.6	9.8	0.8	**9**
10	**23.1**	**23**	7.6	**10.2**	15.5	0.8	**14.7**

TABLE V

OPTIMAL LOAD FLOW P.U. FOR 10 YEARS PERIOD – (B)

Ind	1	2	3	4	5	7	11
1	14.5	8.3	5.7	9.3	0.8	0.8	---
2	14.7	8.3	5.8	9.3	0.8	0.8	---
3	15.3	8.3	5.9	9.3	0.8	0.8	---
4	15.8	8.3	6.0	9.3	0.8	0.8	---
5	17.5	13.9	6.3	9.3	6.4	0.8	**5.6**
6	18.00	13.94	6.4	9.3	6.44	0.8	**5.8**
7	18.5	13.88	6.6	9.3	6.38	0.8	**5.58**
8	19.1	**15.3**	6.8	9.3	7.8	0.8	**7**
9	19.14	**17.3**	7	8.64	9.8	0.8	**9**
10	19.77	**23**	7.6	8.16	15.5	0.8	**14.7**

The examples above show that the distribution utilities can postpone or even reduce investment by taking into consideration direct load control and distributed generation. This could be achieved because distribution network planning is based on maximal annual load whose duration is a couple of hours during the year. Instead of investment into new capacity utility can sign the direct load control agreement and reduce the load during the peak periods. In addition, with this agreement utility can protect itself from extra high wholesale market price by decreasing the load during critical hours.

TABLE VI

OPTIMAL LOAD FLOW P.U. FOR 10 YEARS PERIOD – (C)

Ind	1	2	3	4	5	7	11
1	5.2	8.3	5.7	0	0.8	0.8	---
2	5.4	8.3	5.8	0	0.8	0.8	---
3	6	8.3	5.9	0	0.8	0.8	---
4	6.5	8.3	6.0	0	0.8	0.8	---
5	8.2	8.3	6.3	0	0.8	0.8	**---**
6	8.7	8.3	6.4	0	0.8	0.8	**---**
7	9.2	8.3	6.6	0	0.8	0.8	**---**
8	9.8	8.3	6.8	0	0.8	0.8	**---**
9	10.5	8.3	7	0	0.8	0.8	**---**
10	13.1	12	7.6	0.2	5.5	0.8	**4.7**

Even though distribution utility can benefit from distributed generation; they must also consider that sometimes distributed generators can cause more harm than benefit. Such an example is shown in Fig.5a and Fig 5b. There are two distributed generators and their optimal position can not be chosen by the distribution utility but they must be connected at nodes 2 and 4 due to customer constrains. In addition, the distributed generator at node 4 can not be controlled and it has constant output of 30 p.u.

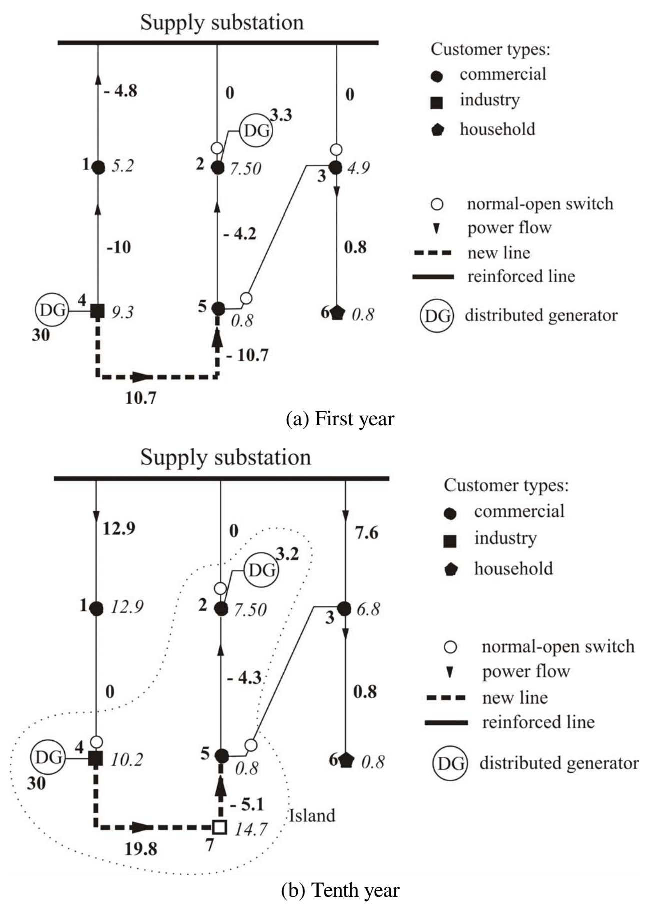

Fig. 5. Optimal Solution for 10 Years Planning Period – Distribution Generator can not be Controlled

As it can be seen in Fig. 5a, two lines should be added to satisfy generator output to node 4 in first year. Moreover, distribution generator that is connected in node 4 will inject power back to supply substation because the load is very light. Directional power protection must be introduced to satisfy new type of the topology and direction of the power flow.

The optimal configuration for the tenth year is that both generators operate within an island. Normally, this type of configuration should be a consequence of a fault in the network but not of an optimal configuration.

IV. Conclusion

Distribution network development planning is a complex task due to a size of a distribution network, and interconnectivity of its elements.

The distribution system planners should take into account directly controllable customers. These customers could contribute to decreased peak load, and therefore, to reduce requirements for a new capacity expansion. In addition, they could reduce load level during extremely high price periods at wholesale market.

Distributed generators have important role in distribution network planning. They could reduce investment in new capacities. On the other hand distributed generators could have negative effects if their locations or sizes are not adequate for distribution system where they are used.

Planners should look for models that do not just resolve technical problems of the system, but also can conduct economic analysis.

The proposed model is a combination of technical and economic analysis. It takes into account the fact that capital investment is limited and should be used effectively. The model determines optimal investment times and resolves technical limitations such as radial power flow and capacity limitations at the same time.

Our further work should be focused on price agreement determination that will satisfy both customers and distribution utilities.

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VI. Biographies

Marija Prica is a PhD student at Carnegie Mellon University. She is a student member of IEEE. She was teaching and researching assistant at the Faculty of technical sciences in Novi Sad, Power Engineering Department, and a part time employee in DMS group Novi Sad from 2000-2005. Her interest is in distribution network planning and relay protecton. She received her B.S. and M.Sc. degree in Power Engineering from the Faculty of technical sciences, Novi Sad in 2000 and 2006 respectively.

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She is a Professor in the Electrical and ComputerEngineering and Engineering Public PolicyDepartments, Carnegie-Mellon University, Pittsburgh, PA. She was a Senior Research Scientist at the EECS Department at the Massachusetts Institute of Technology (MIT) since 1987, and currently holds an Appointment of a Visiting Professor in the newly formed Engineering Systems Division at MIT. Her interest is in control and design of large-scale systems. From September 1999 until March 2001, she was a Program Director for Control, Networks and Computational Intelligence at the National Science Foundation. Prior to her years at MIT, she was a faculty at the University of Illinois at Urbana-Champaign, Cornell University, Ithaca, NY, and Drexel University, Philadelphia, PA.

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