Strategic Planning for Capacity in Power Distribution Grids

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ABSTRACT

Utility planners strive to develop a distribution network which provides economic, reliable, and safe electric energy to the end users. Since the power demand has a tendency to grow, utility companies must cope with the increasing load by continuously upgrading the existing substations and power lines in the grid, or by adding new ones. An alternative solution is to add energy storage and generation sources that are located closer to the customers. This article presents a summary of a research conducted at the Department of Industrial and Management Systems Engineering at WVU pertaining to capacity planning in a deregulated environment. In this research, an integrated approach to the grid planning was considered, where distributed generation (**DG**) sources and energy storages (**ES**) are incorporated into the expansion plan together with traditional options. The objective is to minimize the present worth of installation, upgrade, operation and maintenance, customer interruption, and fuel costs during the planning horizon, while satisfying a set of given criteria. Renewable portfolio obligations, "green" energy credits, as well as restrictions on the available capital for investments are considered in the model, in addition to the technical constraints.

INTRODUCTION

The last decades of deregulation in the power industry have presented utility companies with new challenges of operation in a liberal environment. They must not only meet the growth of electric power demand with the highest reliability and quality, but also improve their operational efficiencies in order to survive in a competitive electricity market. Aging infrastructure, increasing environmental concerns, legislative pressure to reduce greenhouse gas emissions, growing penetration of distributed resources into the grid, and declining reliability of supply are all among the challenges faced by power utilities today. To resolve some of the operational problems in today's grids, the idea of Smart Grid was developed and is being pursued by Modern Grid Initiative in cooperation with the US DOE. Wide deployment of integrated communication across the grid, advanced control methods, metering and measurement (AMI), and advanced grid components will enhance the reliability and security of the electric power grid. It is believed though, that in addition to the "technical" modifications, new methods and tools must be employed during the planning stage in order to facilitate the transition into the smart grids of the future. Strategic decisions regarding network configuration, capacity allocation, as well as type, size and operation schedules of diverse system components significantly affect the overall cost of grid expansion as well as the cost of delivered electric energy.

Traditional Planning Process

Many tools have been designed during the last 40 years to help utility planners in developing reliable, safe, and economical expansion plans (see e.g. [1], [2], [4], [6], [7], [10], and [12]). The planning process starts by defining the boundary of the geographic area considered for expansion, and the duration of the planning period. Then, the growth of electric demand in the grid is forecasted for every year in the planning horizon. Apart from the projected demand in the existing grid, the spatial load growth is also predicted. When forecasts are ready, the projected capacity gaps are estimated for the major components in the grid. A new construction or an upgrade is usually initiated when the power demand is projected to exceed the allowed emergency limits of the grid components. In order to supply electric power to the emerging loads, installation of new power lines and/or substations may be required. At this stage of the planning process, it is required to identify all feeder routings and locations of the potential substations where installation of these components is plausible. Each feeder routing or substation location will have a different cost associated with it. Since the expansion process can also be achieved by upgrading the existing capacities, it is also required to identify the set of candidates for upgrade. This set may include overloaded feeders, transformers, or old equipment which must be replaced. When the expansion costs associated with build or upgrade options are estimated, the planning enters into the final stage, i.e. determination of a good solution. In general, the solution of the problem may be accomplished by generating alternative plans for system expansion, and then evaluating them using given criteria for analysis (e.g. Net Present Value, Rates of Return, etc.). In the case of large scale grids, the solution of the problem is accomplished with the help of computerized optimization or intelligent search techniques.

PROPOSED PLANNING APPROACH

As the electric power industry moves towards "smart" grids of the future, the existing planning methods fall behind, and new tools need to be developed. Modifications of the existing grid, distributed generation, renewable energy resources, energy storage systems, and demand side management must all be considered in the context of grid planning in order to meet the ever-increasing requirements of the power system performance. The planning approach presented in this paper is based on an *integrated* methodology, where distributed generators and/or energy storage devices have an equal opportunity for being in the expansion plan, with traditional options. Under this assumption, the planning task is to determine the optimal mix of distributed generation/storage technologies and their capacities (in addition to any feeder/substation decisions) in order to minimize the expansion cost during the planning period.

Benefits of Distributed Generators

The term *Distributed Generator* is used to describe a small size power-generating unit (rated capacity of up to 30 MW) which is located closer to energy consumers in the distribution grid. A generator may be installed in the distribution substation, at the transfer bus, or directly at the actual loads. Such generators may be owned by a distribution utility or by a customer. If it is owned by a customer, it may sell part or all of its kVA to the utility company on the grid (if it meets some qualifications). Customer-owned generators, both renewable and fossil fuel-based, have already begun to appear on utility grids, and the forecast (www.eia.doe.org) is that a much broader range of generation options will be available in the coming years.

If an installation of a generator is planned by a utility company, then the utility must deploy it in the right place on the grid in order to take full advantage of its benefits. For this scenario, possible advantages may include reduction (or deferral) in transmission and distribution upgrades, improved reliability of supply (resulting in less outage cost), peak shaving, emission credits, lower cost for reserves ancillary services, etc. (see e.g. [3], [9]). If a Combined Heat and Power or a renewable unit is employed, its operation will also result in overall energy cost reduction. The main benefits of distributed generators are summarized in Figure 1.

Benefits of Storage Systems

Storage systems may be used in the power industry to accumulate electric energy generated in one period and use it later when necessary. Many technologies of storage systems are currently available for applications [8]. Some of these technologies have been used in the power industry (e.g. hydro pumped storage), while many others are still under development. It is worthwhile mentioning that apart from the hydro pumped storage, which can be used for *seasonal* and *daily* load leveling, all other technologies are not very popular in the power

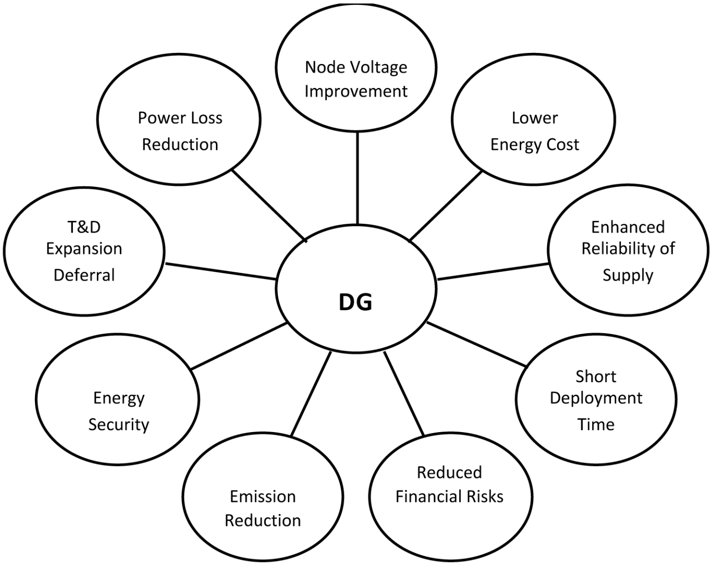

Figure 1. Benefits of Distributed Generators

systems. There are only few countries (Germany, Japan, and recently US) where commercially scaled battery energy storage systems are actually used in the power grids.

An energy storage in power systems may perform different functions, including load leveling, reliability enhancement, emergency power (spinning reserve), frequency and voltage control, and others (see e.g. [11]). Load leveling (or "peak shaving") is used to match supply and demand throughout the day. There are two main benefits which may be targeted in this scenario, i.e. generation efficiency improvement, and transmission and distribution upgrade deferral. Efficiency improvement is achieved by replacing expensive power from the peaking plant, with cheap power from the base-loaded plant (also known as "energy transfer duty"). This may be reasonable from the economic point of view, only if the ratio between the incremental costs of energy during off- and on-peak hours is less than the turnaround efficiency (η) of the ES unit, i.e.:

$$\eta > C_{\text{off-peak}} / C_{\text{on-peak}}$$

Another reason for using load leveling is related to the deferral of transmission and distribution upgrades. Even when the energy transfer duty is not economical, electric power utilities may still implement a "peak shaving" strategy to relieve some of the overloaded transformers or feeders. Regardless of the situation, the economical effect of a storage system must be quantified and compared to the classical upgrade solutions before any decision is made. The main benefits of energy storage systems are summarized in Figure 2.

Mathematical Formulation of the Integrated Planning Problem

The planning task is modeled as a mathematical programming problem and solved using heuristic optimization methods. Binary variables are used to represent one-time decisions (construct or not, upgrade or not, initiate a contract or not, etc.) while continuous variables are used to represent power flows in the lines, capacities of the system components, and voltage magnitudes at the nodes. Due to the existence of binary variables, and because of the non-linear nature of power losses in the lines and transformers, the integrated problem usually reduces to a mixed integer non-linear program (MINL). To mitigate the computational efforts associated with this class of prob-

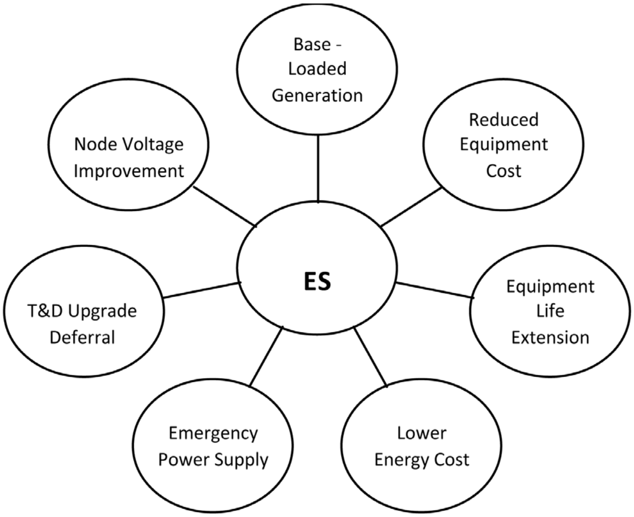

Figure 2. Benefits of Energy Storage Systems

lems, a piecewise linearization procedure is applied to the non-linear power flow terms, in order to convert the problem into a mixed integer linear program (MILP). The mathematical formulation of the resulting minimization problem can be presented in the following general matrix form:

$$\text{MINIMIZE:} \quad EXPANSION\ COST = C_1Z + C_2X$$

SUBJECT TO:

$$\begin{aligned} A_{11}Z + A_{12}X &= D; \\ A_{21}Z + A_{22}X &\leq B_1; \\ A_{31}Z + A_{32}X &\geq B_2; \\ A_{41}Z &\leq 1; \\ Z = 0, 1;\ and\ X &\geq 0; \end{aligned}$$

Where,

C_1 = Vector of cost coefficients for binary variables Z
C_2 = Vector of cost coefficients for continuous variables X
D = Vector of power demands
B_1 = Vector of component maximum capacities
B_2 = Vector that includes other restrictions in the grid
A_{ij} = Nonzero matrices

The cost function of the integrated problem consists of three distinct parts as follows:

$$TOTAL\ COST\ OF\ EXPANSION = A + B - \Gamma;$$

Where,

A = Construction costs

B = Power delivery costs

Γ = Credit from generating "clean" or renewable energy

These parts can be further simplified as:

$$A = A_1 + A_2 + A_3 + A_4 + A_5 + A_6 + A_7;$$
$$B = B_1 + B_2 - B_3 + B_4 + B_5 + B_6 + B_7 + B_8 + B_9;$$
$$\Gamma = \Gamma_1 + \Gamma 2;$$

Where,

A_1 = Cost of building new substations

A_2 = Cost of building new feeders

A_3 = Cost of installing fuel-based generators

A_4 = Cost of installing renewable generators

A_5 = Cost of installing battery storages

A_6 = Cost of upgrading the existing substations

A_7 = Cost of upgrading the existing feeders

B_1 = Cost of energy purchased at the substations

B_2 = Cost of electric demand paid at the substations

B_3 = Reduction in total energy cost by generating renewable energy

B_4 = Cost of energy purchased from the customer-owned generators

B_5 = Cost of fuel to operate the generators

B_6 = Power outage cost due to failure of the transformers

B_7 = Power outage cost due to failure of the power lines

B_8 = Power outage cost due to failure of the storage systems

B_9 = Power outage cost due to failure of the fuel-based generators

Γ_1 = Credits for generating "renewable" energy

Γ_2 = Credits for purchasing "clean" energy

Details of the above variables and costs are beyond the scope of this article.

The MILP problem belongs to the class of NP-hard problems known in optimization theory. These problems are hard to optimally solve, especially for large size networks. To simplify the solution procedure, a two-phase specialized heuristic based on genetic algorithm was developed to produce near optimal solutions in a reasonable amount of time.

CASE STUDY EXAMPLE

To test the developed planning methodology, an electric power distribution grid of a small city was simulated. Electric parameters of the components were simulated based on common values for medium voltage distribution grids. Technical parameters of the generators and battery storages were simulated based on the information provided in the publications of ORNL [5], SANDIA [8] and NETL (2008, 2009) laboratories, as well as information obtained from vendors. Cost data for all components were obtained from the web as well as from vendors. The simulation was performed using MATLAB software and its graphical interface. Although a serious attempt was made to obtain an accurate

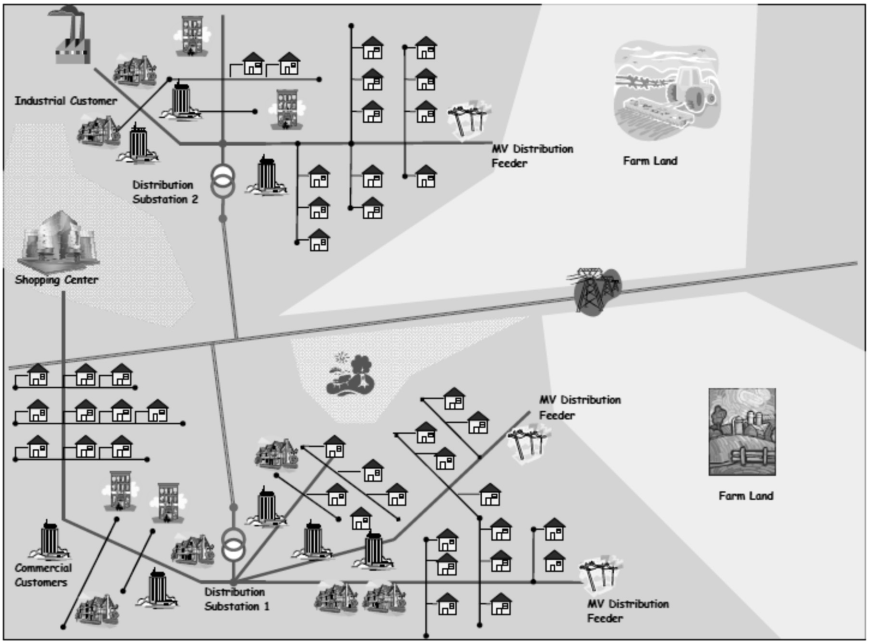

Figure 3. Layout of the Grid at the Beginning of Planning

data about the associated costs, the main objective of the research was oriented towards the development of a planning *methodology*.

Figure 4 shows a simulated forecast of the same city for a 5-year period. Forecasts can be developed based on the historical load growth rates and city development plan. As noted from the figure, it is projected that the residential areas fed by the existing substations will grow significantly over the course of five years thus increasing the tension on the existing grid. In addition, in the eastern part of the city the farm land will shrink and three additional load areas will emerge. The utility company therefore will need to provide capacity for these customers to be connected to the power grid. The peak load at the beginning of the planning horizon at SS #1 (39.7 MVA) is already close to the emergency limit (41.4 MVA) of the transformers, and this substation will not be able to support the growing demand after two years. Based on the projected load growth in the grid, it is also estimated that the capacity limit for SS #2 (8.1 MVA) will be violated in year 5. The problem of exceeding the capacity is even more severe for the feeders. Two feeders connected to SS#1 (FR #3 and FR #5) already

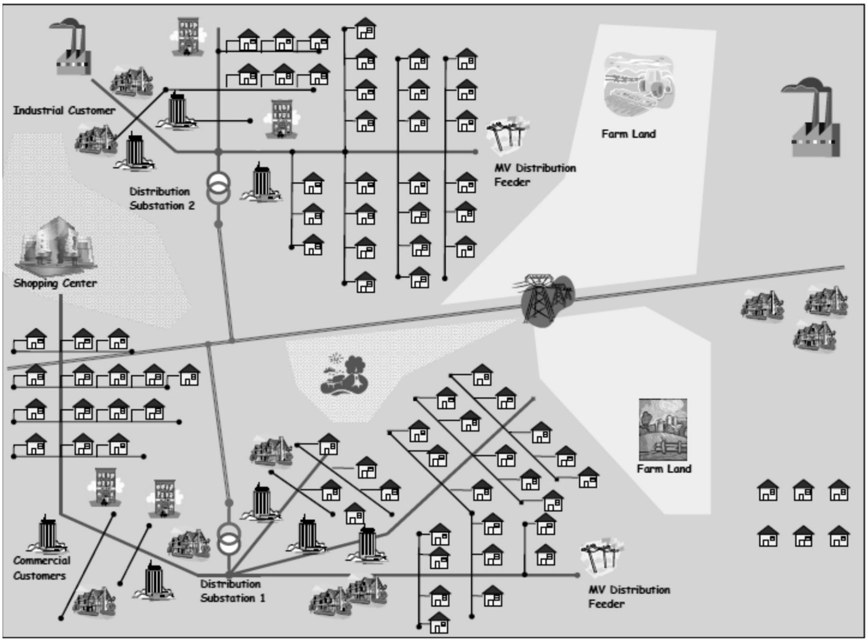

Figure 4. Forecasted Grid Layout in Year 5

have excessive loads in the peak season, and other feeders are forecasted to run out of capacity in a few years if no corrective measure is undertaken. Load growth in the grid may also create an excessive voltage drop along the lines and violation of the low voltage limits in some locations. In this situation, the utility company must develop a suitable expansion plan, and add enough capacity to the existing grid to resolve congestion and possible outage issues.

To that end, a utility planner must start with a survey of the existing grid to find potential locations for new substations, potential routes for power lines, as well as sites where installation of distributed resources is plausible. Figure 5 shows the output of a simulated survey. Each node has a label showing the type of a distributed resource that can be potentially installed at that node. The labeling code is given beneath the figure.

As Figure 5 suggests, locations of two potential substations #3 and #4 have been identified during the survey. It is also possible to upgrade the existing substation #2 up to 12 MVA. Seven new routes

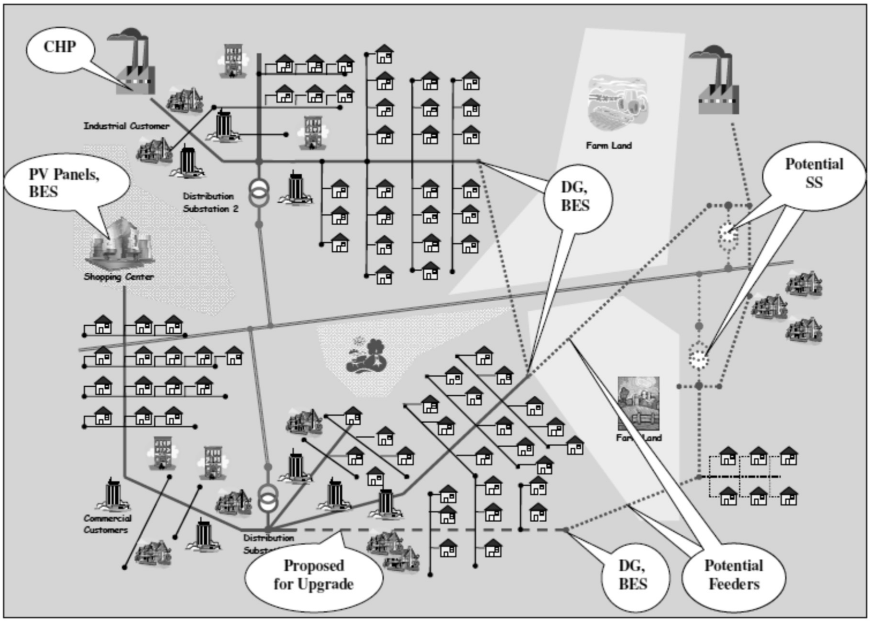

Figure 5. Map of Available Expansion Options
DG-Fuel based distributed generator, BES – battery energy storage, CHP-combined heat and power unit, SS-Substation

for wire installation are proposed (FR #10 – FR #16 are shown as dotted lines) together with an upgrade of FR #1 (shown as a dashed line). It is feasible to install fuel based distributed generators, as well as battery storages in the locations shown on the figure. Power from the customer owned generator could be purchased at the CHP plant, and there is a possibility of installing photovoltaic arrays at the roof of the shopping mall. The following main economic parameters were used in this example:•

- Planning horizon, 5 years
- Three phase balanced power flow with spacing ID-500
- Distribution voltage, 25 kV phase to neutral
- Demand growth rate, 4% per year
- Useful lifetime of feeders and substations, 30 years
- Useful lifetime of fuel based distributed generators, 15 years
- Useful lifetime of battery storages, 5 years
- Useful lifetime of renewable generators, 10 years
- Average customer interruption cost, $20/kWh
- Price of a REC (Green Tag) is $100/MWh
- Maximum allowed voltage drop at the load bus, 5% of the base voltage
- Maximum available capital for asset acquisition in each year is defined as $10 million for years 1 through 5.
- Safety buffer between the rated and emergency capacities of transformers and feeders, 10%
- Credits for generating/purchasing "clean" energy are not available
- Renewable/clean portfolio requirement, 500 kW of installed capacity by year 5
- Fuel cost escalations, 3% per year (applied to energy cost from all sources)
- Construction and equipment cost escalation, 5% per year
- Property tax, 3% of the capital cost (Ad Valorem)
- Interest rate, 8% per yr

In addition to the data above, there is a great deal of information which must be available to the planner in order to develop a good plan. Electrical parameters of transformers and power lines, technical specifications of generators and battery storages, power generation potential, site-specific characteristics for installation including initial and continuous costs, energy and demand cost at the substations as well as energy cost from the customer owned generator, and other parameters were used in the computations. These parameters are not given in the article due to space constraints.

At this stage, a utility planner must make a strategic decision about the future of the city's grid and choose the best expansion plan among all possible alternatives, subject to the set of given technical, financial, and legislative constraints.

SOLUTION

To find an optimal expansion plan for the case study problem, a heuristic optimization approach was used. The planning problem was formulated in the mathematical programming language and solved using a two stage genetic algorithm. Appendix 1 gives a description of the different costs associated with grid expansion, which were used by the optimization algorithms to compare between different alternatives. Figure 6 summarizes the output of the algorithm for the test problem. As noted from the figure, in year 1 the expansion plan includes the installation of a battery storage and a renewable generator at the Shopping Center, installation of a new feeder between the areas served by two substations (FR #10), upgrade of substation #2, upgrade of feeder #1, and the initiation of a contract with customer owned CHP generator located at the industrial plant. A new substation (SS #3) and five additional feeders (FR 11, FR 12, FR 13, FR 14, and FR 15) need to be constructed over the course of four years. Installation of all other resources (e.g. generators) has been rejected by the optimization algorithm as not economical. All demand, capacity, and voltage constraints are satisfied in the grid in each year.

Figure 7 shows a simplified, one-line diagram of the city circuit with on- and off-peak power flows in the main feeders in year 5 (in MVA/Phase). As noted from the figure, the battery storage consumes 0.418 MVA/phase during the charging period and supplies about 0.671 MVA/phase into the grid during the peak hours. Similarly, 1.667 MVA/phase is injected into the grid by the CHP plant during peak hours, with no dispatch during the off-peak period. Power flows vary from year to year due to the growth in demand, variation in energy cost

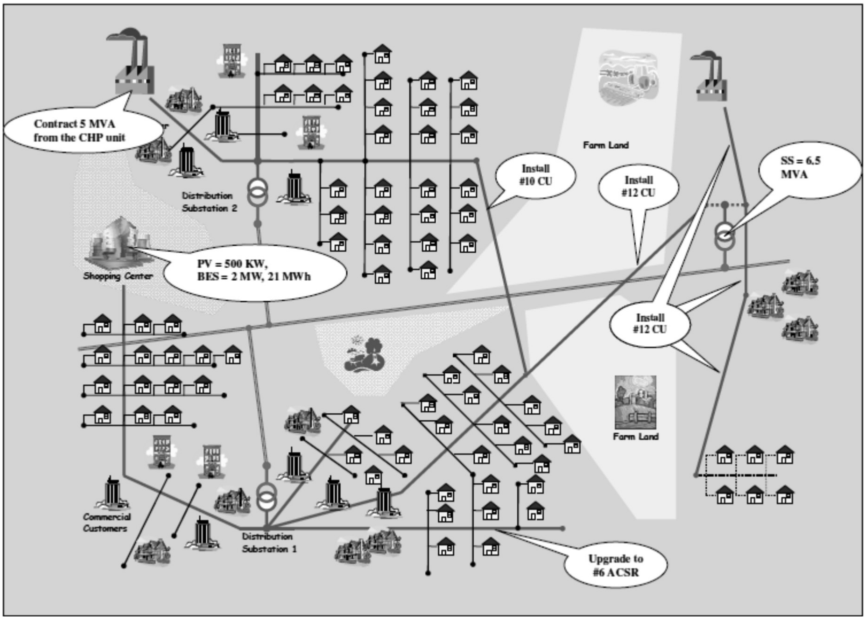

Figure 6. Optimal Expansion Plan for a 5-Year Planning Horizon

at different sources, power limits in the lines, as well as node voltage constraints.

It is important to realize that results of the optimization algorithms are extremely sensitive to the economic parameters used in the formulation, and any variation in the value of these parameters may significantly change the optimal expansion plan. Therefore, no preference may be given to a particular technology solely based on the results shown in this article. Depending on the geographic location of the distribution area planning, type of utility company, physical constraints in the grid, associated equipment and installation costs, tax rates, cost of fuel, and political and social issues, a different mix of technologies may deliver the best economic effect.

CONCLUSIONS

A new approach is presented in this article, to develop a "strategic plan" for expansion in electric power distribution grids. The integrated problem was modeled and solved using mathematical programming

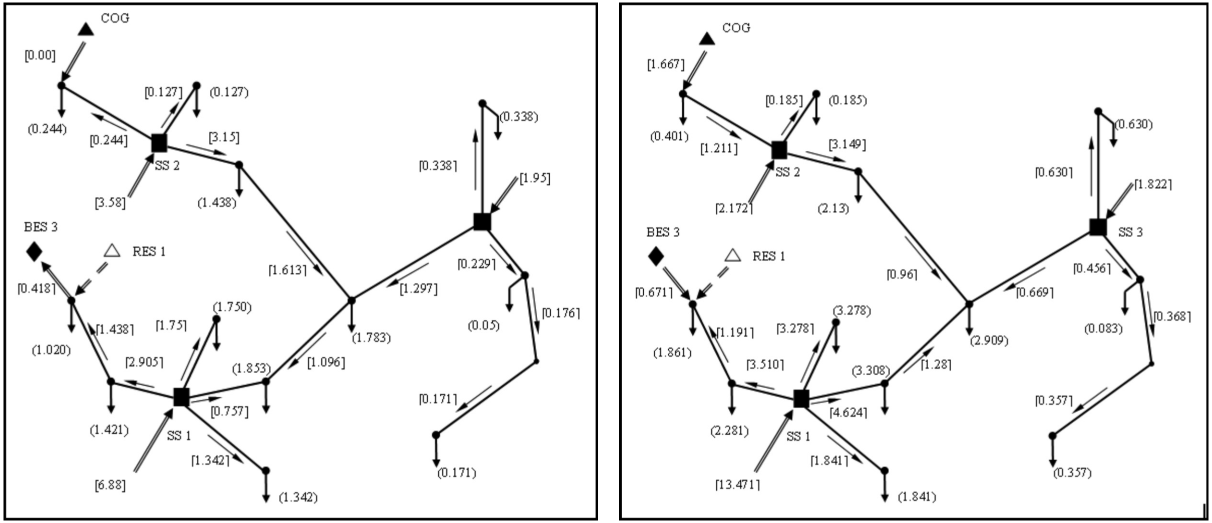

Figure 7. Off- and On-peak Power Flows in Year 5 (in MVA/Phase)

and intelligent optimization techniques. The objective of the problem is to minimize the present worth of the costs associated with the installation and upgrade, operation and maintenance, power loss, customer interruption, and energy and fuel usage, throughout the planning horizon while satisfying a given set of constraints. Thermal capacities of feeders, node voltage constraints, reliability and security issues, renewable portfolio obligations, and credits from generating renewable or "clean" energy, as well as restrictions on the available capital for investments, were considered in the context of planning. It was found that the modeling approach together with the solution algorithms may provide a good foundation for a decision support system for utility planners. The algorithms can help the decision maker to integrate a diverse portfolio of distributed energy resources into the planning process along with conventional solutions. Important decisions regarding locations, types, capacities, as well as installation/upgrade timings of grid components are obtained using the methods presented in the article. The developed algorithms also help the grid planner to decide on which of the customer owned generators located within the utility's boundary need to be incorporated into the expansion plan. Generation dispatch and battery charge/discharge schedules are generated as an output of the algorithms.

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APPENDIX 1—COSTS ASSOCIATED WITH THE GRID EXPANSION