Implications of the Smart Grid Initiative on Distribution Engineering

Final Project Report - Part 1

Power Systems Engineering Research Center

*Empowering Minds to Engineer
the Future Electric Energy System*

Implications of the Smart Grid Initiative on Distribution Engineering

Part 1 - Characteristics of a Smart Distribution System and Design of Islanded Distributed Resources

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Power Systems Engineering Research Center

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Acknowledgements

Executive Summary

In the PSERC project "Implications of the Smart Grid Initiative on Distribution Engineering," the research team targeted specific distribution engineering elements and practices that can benefit from smart grid technologies when renewable energy and energy storage resources are used at the distribution level. The research included:

1) identification of the characteristics of a *smart* distribution system
2) design of networked distribution topologies with renewable energy sources, and energy storage devices aimed at higher reliability and lower capital costs
3) operation of networked distribution system topologies aimed at restoration after loss of supply
4) quantification of the impact of penetration of plug-in hybrid electric vehicles (PHEVs) on demand response and
5) development of distributed algorithms to control voltages at distribution levels.

The underlying objectives of the research were:

1) selective conversion of legacy radial systems to networked distribution systems
2) use of sensory signals at the local and hierarchically higher levels for both supervised and fully automated control
3) development of enabling strategies and interconnection configurations for renewable resources at the distribution system level.

The research was divided into four parts discussed below.

Part 1: Characteristics of a *smart* distribution system and redesign of legacy radial systems into partially networked systems

The reported work in Part 1 focused on the definition of some characteristics of a smart distribution system and the design of islanded distributed systems with distributed generation sources. A survey was dispersed to members of the electric power industry to develop a definition and preferred facets of a 'smart distribution system' that (1) optimizes distributed assets; (2) incorporates distributed energy resources; (3) integrates massively deployed sensors and smart meters; (4) enables consumer participation in demand response; (5) uses adaptive and self-healing technologies; (6) makes use of advanced tools; (7) integrates smart appliances and consumer devices; and (8) possess the ability to operate in islanded or grid-connected mode. The results of this survey may be applied in determining the composition of simulation systems and areas where future research can be focused.

Work reported in this part also included distribution system planning to add networked feeders to improve reliability. A planning optimization problem called "the feeder addition problem" was defined as:

"given a distribution system with distributed generation sources, add networked connections such that the cost of the addition is feasible while improving the reliability and satisfying power flow constraints under islanded conditions".

The system constraints considered include the operating requirements, such as voltage levels and branch loading. Two different optimization methods to balance cost and reliability were explored using two test systems. Both optimization methods were able to improve the system reliability for cases where distributed generation output exceeded feeder demand.

Part 2: Quantification of the impact of PHEVs on distribution system demand response

The planning approaches presented in Part 1 w ere extended to optimal distribution asset allocation and quantification of the impact of plug-in hybrid electric vehicles (PHEVs) at selected penetration levels. The reliability optimization problem was to determine locations for distributed generators and feeder intertie connections in a legacy radial distribution system in an islanded mode of operation. An extended methodology of an existing Multi-Objective Genetic Algorithm (MOGA) was used. The MOGA was applied to a test system in which two types of load modeling were used. Satisfactory design solutions were obtained.

A Linear Programming (LP) optimization method was used to determine the impact on distribution systems of penetration of a PHEV fleet with vehicle-to-grid features. The method is based on a probabilistic simulation of daily behavior of a PHEV fleet. It was used to determine the charging patterns of the vehicles for utility peak-shaving purposes and for the benefit of the owner. The charging patterns of the PHEV simulated fleet were used to determine the impact of PHEVs in a distribution test system again under islanded mode of operation. Finally, the impact of PHEVs in the redesign of such distribution system islands was also analyzed.

Part 3: Restoration, state estimation and reliability enhancement in distribution systems

A new operating paradigm of distribution system design, operation and control is needed with high penetrations of distributed generation and distributed energy resources. Enhancing reliability with these resources requires new control and system operations, massive deployment of sensors, increased levels of data communications, and increased networking of distribution feeders. In this research, reliability enhancement methods and applications were developed, such as distribution state estimation that utilize sensor information to increase visualization, control and allow enhanced operation of the distribution system.

Reliability enhancement and fast restoration using algorithms were created based on the binary bus connection matrix. This research provides a table lookup technology for reenergizing distribution system loads after a blackout of the transmission system feed points. The method is based on the objective of minimizing the unserved load energy. The method is appropriate for radial and networked systems.

In the future many more sensors will be present in distribution systems. These sensors will allow simultaneous synchronized measurements of voltages and currents. In this research, these measurements, plus the system impedance and connection information, were used in a s tate estimation algorithm. The resulting distribution state estimates make all voltages and currents in the distribution system available for control of controllable elements of the system, e.g., demand side management, distributed generation which has controllable components, energy storage in the system, and possibly system interruption/restoration components. The estimation methodology accounts for differences between distribution and transmission systems including the need for three phase detail and the high *R/X* ratios commonly encountered in distribution systems. A test bed was used to demonstrate an algorithm and alternative formulation for

distribution system state estimation utilizing synchronized phasor measurements throughout the distribution system.

Relating to reliability, the report gives an overview of measures of reliability. How these measures might be improved for distribution systems is outlined.

Part 4: Distributed algorithms for voltage control in electrical networks

Distributed energy resources can be used to provide the reactive power support required to stabilize and control voltage in electric power systems. As the number of distributed energy resources continues to increase, traditional approaches to the design and control of distribution networks will no longer be adequate. For example, on a clear day with high incident irradiance, it is possible for the active power injections from photovoltaic systems to reverse the flow of power and cause over-voltages on certain buses. The impacts of photovoltaic systems and plug-in hybrid electric vehicles on distribution networks are of particular interest due to the potentially high penetration of these devices in the years to come. Although the contribution of each device is small, collectively, they can have a significant impact on system reliability and performance. Since the placement and number of these devices are unknown to system operators, a distributed control strategy is desired to determine the reactive power support provided for ancillary services. This report presents a resource allocation algorithm and an adaptive algorithm that modifies its behavior to respond to voltage limits on a radial distribution system. The ability of these distributed algorithms to control voltages is illustrated in a series of case studies.

Major Results

The major results of this research effort are:
1) A survey based identification of imperative characteristics of a *smart* distribution system
2) A multi-objective optimization of the redesign of legacy distribution systems to networked topologies for increased reliability at lowered costs
3) A linear programming approach to the scheduling charging and discharging characteristics of a PHEV fleet in a distributed island resource aimed at demand response
4) An optimization theory based approach to restoration of distribution systems following a blackout of the transmission system
5) Development of a distribution class state estimator suitable for three phase state estimation (including unbalanced cases), systems of high R/X ratio, and mixed three phase / single phase configurations
6) The formulation and an example of how synchrophasor technology can be used in distribution systems
7) Development of a resource allocation algorithm and an adaptive algorithm that modifies its behavior to respond to voltage limits on radial lines.

Project Publications

1. H. E. Brown, S. Suryanarayanan, G. T. Heydt, "Some characteristics of emerging distribution systems under the Smart Grid Initiative," Elsevier The Electricity Journal, vol. 23, no. 5, pp. 64-75, Jun 2010.

2. H. Brown, D. A. Haughton, G. T. Heydt, S. Suryanarayanan, "Some elements of design and operation of a smart distribution system," in Proc. IEEE Power & Energy Society Transmission & Distribution Conference & Expo, New Orleans, LA, Apr. 2010.

3. H. Brown, S. Suryanarayanan, "Improving the reliability of islanded distribution systems with distributed energy resources via feeder interties," under review, IEEE Transaction on Smart Grid, Aug 2011.

4. H. Brown, "Implications of the smart grid initiative on distribution system engineering: improving reliability of islanded distribution systems with distributed generation sources," M.S. thesis, Division of Engineering, Colorado School of Mines, Golden CO, May 2010.

5. J. Giráldez, "Planning distribution system resource islands considering reliability, cost and the impact of penetration of plug-in hybrid electric vehicles," M.S. thesis, Division of Engineering, Colorado School of Mines, Golden CO, May 2011.

6. J. Giráldez, S. Suryanarayanan, D. Zimmerle, "Planning microgrids considering PHEVs with V2G for peak-shaving and reliability," under preparation, IEEE Transaction on Smart Grid, Aug 2011.

7. J. Giráldez, A. Jayantilal, J. Walz, H. E. Brown, S. Suryanarayanan, S. Sankaranarayanan, E. Chang, "An evolutionary algorithm and acceleration approach for topological design of distributed resource island," in Proc. 2011 IEEE PES PowerTech, Trondheim, Norway, Jun 2011.

8. Y. Chen, X. Jiang, and A. Dominguez-Garcia, "Impact of Power Generation Uncertainty on Power System Static Performance," in Proc. North American Power Symposium (NAPS), Boston, MA, Aug 2011.

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10. B. Robbins, "Distributed Algorithms for Voltage Control in Electrical Networks," M.S. thesis, Department of Electrical and Computer Engineering, University of Illinois at Urbana-Champaign, May 2011.

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17. B. Sathyanarayana, G. Heydt, M. Crow, F. Meng, "Test bed evaluation of future power distribution systems with renewable resources," in Proc. North American Power Symposium (NAPS), Mississippi State MS, October, 2009.

18. D. Haughton, G. Heydt, "Smart distribution system design: automatic reconfiguration for improved reliability," in Proc. IEEE Power and Energy Society General Meeting, Minneapolis MN, July 25 – 29, 2010.

19. G. T. Heydt, "Future renewable electrical energy delivery and management systems: energy reliability assessment of FREEDM Systems," in Proc. IEEE Power and Energy Society General Meeting, Minneapolis MN, July 25 – 29, 2010.

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Student Involvement

H. E. Brown, M.S. (thesis), Division of Engineering, Colorado School of Mines, Golden, CO, May 2010 (employed with: Burns & McDonnell, Houston, TX).

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Part 1

Characteristics of a Smart Distribution System and Design of Islanded Distributed Resources

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3FDR	Simplified three-feeder test system
$a(y)$	Fitness function for the genetic algorithm example
ACO	Ant colony optimization
ACSR	Aluminum conductor steel reinforced
AHP	Analytic hierarchy process
AMI	Advanced metering infrastructure
ANSI	American National Standards Institute
ARRA09	American Recovery and Reinvestment Act of 2009
ASAI	Average system availability index
AV	Average
$Av[a(y)]$	Average value of the fitness function for the genetic algorithm example
B	Bus connectivity matrix
B_{Lk}	Percentage branch loading
BPL	Broadband over power lines
C_i	Cost of connection i
CAES	Compressed air energy storage
CDG	Conventional distributed generation
CDMS	Commercially operated distribution management system
CHP	Combined heat and power
d	Distance between modeled feeders
DER	Distributed energy resources
DG	Distributed generation
DMS	Distribution management system
DOE	Department of Energy (United States)
DS	Distributed storage
EA	Evolutionary algorithm
EAC	Electricity Advisory Council (United States)
EISA07	Energy Independence and Security Act of 2007
EMS	Energy management system
ENS	Energy not supplied

EPRI	Electric Power Research Institute
EPS	Electric power system
EU	European Union
f(x)	Total cost of the feeder additions for the optimization methods
f_{max}	Maximum allowed cost of the project
g(x)	Power flow equations used in optimization methods
GA	Genetic algorithm
GEO	Governor's Energy Office (of Colorado)
GMR	Giant magneto-resistance
h(x)	ENS evaluation for optimization methods
h_o	Value of ENS for the base case
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
$\mathcal{L}$	Total installed load at load point where RE resource is installed
LEMS	Local energy management system
LIRP	Local integrated resource planning
M	Number of system slack buses
MAIFI	Momentary average interruption frequency index
N	Number of possible topologies
N	Number of responses to survey question (sample size)
N_B	Number of buses
N_{branch}	Number of branch loading violations
N_{bus}	Number of bus voltage violations
N_c	Total number of possible connections
NETL	National Energy and Technology Laboratory (United States)
NIST	National Institute of Standards and Technology (United States)
NREL	National Renewable Energy Laboratory
P	Overall penalty applied to the ENS
P_{branch}	Penalty function for branch loading violations
P_{bus}	Penalty function for bus voltage violations
P_j	Output of slack bus *j*
P_{out}	Output power of system DER
PCC	Point of common coupling

PHEV	Plug-in hybrid electric vehicle
PMU	Phasor measurement units
$Prob_i$	Probability of an individual to be selected for the mating pool
PSO	Particle swarm optimization
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
$Q(x)$	Vector of objective functions $f(x)$ and $h(x)$
R	Total DG rating
R_{CDG}	Total rating of the CDG resources
R_{RE}	Total rating of the RE resources
R	Desired number of connections
RBTS	Roy Billinton Test System
RE	Renewable energy
RMS	Root-mean-square
RPS	Renewable Portfolio Standards (United States)
S_{ab}	Branch loading between buses a and b
St	Number of individuals in a population for the genetic algorithm example
SA	Simulated annealing
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SARFI	System average RMS variation frequency index
SCADA	Supervisory control and data acquisition
SD	Standard deviation
SGI	Smart Grid Initiative
SM	Smart meter
T	is the annual outage time used for the simulations
U_i	Annual outage time at load point i.
UPS	Uninterruptible power supply
V_a	Voltage at bus a
WACS	Wide area control system
WAMS	Wide area measurement system
x^*	Global optimum
Y	Individual in genetic algorithm example

ε	Length of a possible connection
$\boldsymbol{\eta}$	Number of possible connections if one connection will be made
Λ	Distance of 'from' bus to feeder slack bus
Ξ	Distance of 'to' bus to feeder slack bus
χ_i	Binary connection variable

CHAPTER 1

INTRODUCTION

The electric power industry has experienced many changes in the years between 1999 and 2009. An emerging US Federal policy, commonly known as the "Smart Grid Initiative" (SGI), is expected to have many different implications on electric power engineering in the US. Meanwhile, other analogous policies are expected to affect power engineering in various other countries [1]. This chapter outlines the objectives, motivations, and scope of this research, accompanied by a literature review.

In this report, the work is concerned with the idea of incremental changes in the existing distribution system as it moves toward becoming a smart distribution system. Unfortunately, as will be described in Section 1.4.1, there is no clear consensus on what a smart distribution system should look like, even as most smart grid related changes will happen at the distribution level. An example of incremental changes that could be made in an evolving distribution system examined in this work is the addition of feeders to form a meshed distribution system in the presence of renewable energy (RE) resources. Currently, many distribution systems have the potential to be meshed, with the presence of normally-open tie switches, but most are operated in a radial topology. If a meshed distribution system is the goal, however, it will change the way that distribution systems are planned; this report will discuss a new planning approach for meshed systems.

1.1 Objectives

The objective of this report is two-fold – to determine current electric power industry expectations of the smart grid policy with respect to electric distribution systems and to develop design techniques that may be used in emerging distribution systems. To accomplish these complimentary objectives, a survey seeking a definition of a smart distribution system was developed and disbursed to members of industry. Selected results from the survey were used to define a distribution engineering problem that seeks to modify the topology of a legacy radial distribution system into a selectively meshed network in order to maximize the reliability under islanded conditions when distributed generation (DG) sources are connected to the distribution system.

1.2 Motivation

The SGI was outlined in Title XIII of the Energy Independence and Security Act of 2007 (EISA07) as the official policy of modernization of the electricity transmission and distribution networks in the US [2]. The ten points describing a smart grid, which are discussed in Section 1.4.1, appear to be purposefully vague, focusing on the expected actions of and outcomes for the smart grid, rather than the

functional and technical specifications used to implement the smart grid directly. The SGI should be considered as a guiding document to smart grid development. A *smart grid* incorporates, at both the transmission and distribution level, many of the technologies and functions outlined in the SGI. It is possible that a smart grid could be implemented differently in different locales, while having similar outcomes. A *smart distribution system*, considers only those elements of a smart grid that are incorporated at the distribution level. However, there appears to be no consensus about which specific technologies and functions should be applied at the distribution level and how they should be incorporated [3]. By finding an existing industry definition of a smart distribution system from a functional and technical perspective, it is possible to create a framework for future and current research. Hence, a survey aimed at defining some characteristics of a smart distribution system in the perspective of practicing distribution engineers and other significant participants was deemed as an appropriate first task for this report.

The second part of this report is a practical application of the smart distribution framework identified by the aforementioned survey to an emerging challenge in distribution system engineering, i.e. maximizing the utility of RE resources in distribution systems. Under current interconnection guidelines, system users may interconnect DG sources at any point in the system, provided that the sources meet certain interconnection requirements, such as no reactive power injection at the point of common coupling (PCC) [4]. The SGI implies that a smart grid would contain DG sources that are active electricity market participants and key players used to increase system reliability. Compared to conventional DG sources however, RE resources have special challenges that include lower efficiencies, higher variability, and, for some, non-dispatchability. The work in this report attempts to take these considerations into account at the planning stage for distribution system expansion, specifically with respect to adding interconnecting feeders.

1.3 Scope

This section describes what was considered in the research leading to this report, as well as what was not considered. The survey focused on the applications of the smart grid to the electric power distribution network; furthermore, it was primarily concerned with the functional and technical definition of a smart distribution system, rather than with existing standards (at the time this research began, smart grid standard development had just begun).

The distribution system problem of selectively modifying legacy radial topology to maximize reliability is focused on an islanded distribution system where the locations and types of DG sources are known. An additional formulation of the problem is where to place DG sources in order to maximize reliability, but that is not considered in this report.

1.4 Literature review

As mentioned, there are two major areas of research in this report: emerging distribution systems under the SGI and feeder reconfiguration in the presence of DG sources, including renewable resources. Thus, this literature review will be split into two parts such that the corresponding state-of-the-art may be easily organized between the SGI and distribution system engineering.

1.4.1   Compendium of smart grid and smart distribution system efforts

The philosophy of a smart grid was outlined in Title XIII of the EISA07 which defines the official policy of modernization in the electricity network infrastructure in the US. This legislature outlines ten points describing a smart grid [2]. For completeness of this document, the ten salient points of the SGI are reproduced from [2]:

   i.   Use digital controls to improve security, reliability, and efficiency.

   ii.   Dynamically optimize grid resources and operation.

   iii.   Integrate DG sources, including renewable resources.

   iv.   Develop and deploy resources for demand response and energy efficiency.

   v.   Develop and deploy smart technologies for automation, communication, and metering.

   vi.   Integrate smart appliances and consumer devices.

   vii.   Deploy peak-shaving technologies and electricity storage devices.

   viii.   Provide consumers control options and timely information.

   ix.   Develop standards for grid communication and interoperability.

   x.   Identify and lower unnecessary barriers to smart grid development.

The SGI does not specifically relate to either distribution or transmission; both areas are addressed in the points listed above. Certain points may be specifically related to distribution engineering, such as (iv), (vi), and (viii) in the above list, but the initiative itself is mostly neutral as to whether the points are for distribution or transmission.

An earlier policy that served as a harbinger to the SGI is the "Grid 2030" report which outlined the future direction of evolving power grids for the second 100 years of electrification in the US [5]. This report found that the existing grid was aging and inefficient, with investments at an all-time low [5]. It further specified that regulatory changes were not having the desired effect and the information technology revolution had not yet affected the electric power industry at the same level as it had transformed other industries [5].

Grid 2030 identified several promising technologies for incorporation in the electricity grid, such as DG, distributed intelligence, advanced energy storage, smart controllers, and power electronics [5]. All of these technologies are mentioned either explicitly or implicitly in the SGI. The overall vision proposed by Grid 2030 was a national electricity backbone, providing efficient generation from many sources to

take advantage of varying seasonal and regional peak differences, which would be supported by regional interconnections and local distribution systems, which may be mini- and/or microgrids [5]. Microgrids are local distribution networks that incorporate DER in such a way that they may operate as islands in the grid system, while meeting local loads according to customer preferences [6]. Research into various operational aspects of the microgrid, such as DG and control systems is ongoing [6-9]; research completed in the microgrid context, such as DG usage, is likely to be applicable to projects related to the smart grid.

In 2004, two similar ideas about intelligent power grids were developing – GridWise in the US and SmartGrid in the EU [10]. The GridWise program focuses on updating the electric grid with advanced sensing, DER, and advanced communications and controls; to accomplish this, the program is engaged in research and standards development, such as supporting the Institute of Electrical and Electronics Engineers (IEEE) 1547 set of DG interconnection standards [10].

Title XII of the Energy Policy Act of 2005 (EPA05), which was signed into US law in August 2005 by the 43rd President, Mr. George W. Bush, details amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA) [11, 12]. The amendments stipulate that net-metering and time-based rate schedules should be made available by utilities upon consumer request [11]. Net-metering is the practice of measuring the difference between the electric power taken from and supplied to the grid by a given customer. Time-based rate schedules include differing prices for electricity consumed at different time of day and could be based on time-of-use pricing, critical peak pricing, real-time pricing, or load-shedding pricing [11]. Net-metering and time-based rate schedules resurface as key factors in the EISA07 definition of a smart grid, (v) and (viii) which were previously outlined.

After the passage of the SGI, the National Energy Technology Laboratory (NETL) outlined the "Modern Grid Strategy", which comprises thirteen documents addressing the overall vision, characteristics, and technologies [13]. Characteristics of a modern grid include [13]

i. *Self-healing*, which uses a networked design to communicate nearby problems and detect patterns before an event occurs. That is, the system is aware of existing problems and can avoid high risk situations. To automate on a system-wide scale requires massively deployed sensors, advanced relaying, and high speed switching to dynamically reconfigure. For this to feasibly occur, advances are required in critical technology areas, such as sensing, DER, and communications systems.

ii. *Motivates and includes the consumer* through advanced metering, smart thermostats and appliances, DG, and energy storage. A unique definition of DER was used in this report: a DER is a technology that enables a customer to participate in demand response.

Development of a consumer interface is required, as well as consumer education and incentives to achieve widespread participation.

iii. *Resists attack* from both cyber and physical realms. System security will be enhanced by massively deployed sensors, DER, advanced control, and communications.

iv. *Provides power quality for 21st century needs* by incorporating technologies to enable power quality on demand, and corresponding pricing structure – higher power quality is more expensive.

v. *Accommodates all generation and storage options* through incorporation of DER at all voltages; DER will be distributed at lower voltages and aggregated at higher voltages. To achieve this, dynamic pricing, sensors, controls, and communication are required. DER must automatically start, load, and shut down in response to controls, represent a significant amount of capacity, and integrate safely and reliably with legacy system. If this happens, DER integration will give the benefit of being the right size, in the right place.

vi. *Enables markets*, which should be long-term, day-ahead, and real-time.

vii. *Optimizes assets and operates efficiently* using dynamic ratings and condition-based maintenance. In this definition, all assets will interact to maximize functionality and minimize cost. According to this model, optimization at the distribution level requires minimizing losses.

Key technologies to enable this definition of a modern grid (which is highly aligned with the definition of a smart grid in the SGI) are integrated communications, sensing and measurement, advanced components and control methods, and improved interfaces and decision support [13]. Integrated communications require more standards, especially for advanced meter reading and broadband over power lines (BPL) communication [13]. The information supplied by sensing and measurement devices should include power factor, power quality, phasor relationships, temperature, outages, power consumption profiles; furthermore, these must be supplied at a low cost and small size, with easy maintenance and security assured in order to meet utility needs [13]. Advanced components include power electronics, super-conducting cables, and plug-in hybrid electric vehicles (PHEVs) [13]. Advanced control methods depend heavily on communication and sensing and will ideally collect data and monitor components, analyze data, diagnose and solve problems, and take autonomous action where appropriate [13]. The Modern Grid Strategy aligns with most points described in the SGI, and explains them in more detail. However, it is still focused on the grid as a whole and does not exclusively deal with distribution system changes.

In [14], concerns with the magnitude of the challenge to create a smart distribution system are raised. The authors of [14] contend that digital control of the power delivery network and two-way

communication with customers and market participants are essential to the smart grid [14]. Intelligence at the distribution level was limited to less than 75% at the substations and between 15 and 20% of the feeders [14], which illustrates the magnitude of the challenge to bring smart grid ideas to the distribution level. The authors of [14] do not argue that the smart grid cannot be achieved at the distribution level, but expound the need for realistic expectations.

In 2008, the Electricity Advisory Council (EAC) of the US Department of Energy (DOE) issued a report to discuss opportunities and challenges associated with updating the electric grid under the smart grid paradigm [15]. This report addressed customer benefits of the smart grid, including cost savings from peak load reduction and increased energy efficiency, consumption management, and convenience of DG and advanced metering [15].

The American Recovery and Reinvestment Act of 2009 (ARRA09), popularly called the "Economic Stimulus Package," was signed into law by the 44th US President, Mr. Barack H. Obama in February of 2009, and called for $4.5 billion for smart grid-related activities [16], with the potential for an additional $34.6 billion in funding for smart grid projects [17]. After the passage of ARRA09, activity in smart grid standards development increased [17]. Organizations involved in standards development include the US National Institute of Science and Technology (NIST), IEEE, American National Standards Institute (ANSI) and the International Electrotechnical Commission (IEC) [17].

Existing projects primarily include smart meter rollouts; utilities with extensive smart meter roll-outs include Xcel Energy, Southern California Edison, CenterPoint Energy, Oncor Energy, Austin Energy, and many more [18-24]. Xcel Energy's smart meter roll-out is part of a greater smart grid demonstration project called "SmartGridCity[TM]", located in Boulder, Colorado, which will offer insight into how a smart grid will work in a real community [18]. It is pertinent to note that after the ARRA09, the State of Colorado pursued funding options in smart grid demonstration projects [25] and considered how to prepare the workforce for a smart grid and advanced energy economy [26].

Reference [3] gives an overview of current research into smart grid technologies and systems, in addition to discussing the design implications of the smart grid on the distribution system. Distribution system design is expected to change in the following ways: peak demand will be a driver for advanced metering infrastructure (AMI), the design process must shift from individual feeder considerations to interconnected feeders, DER will have no appreciable effect on the system until penetration exceeds 15%, and automation will incorporate switching and protection functions [3]. Perhaps the most important idea expressed in [3] is that as the penetration of DER increases, the distribution system will begin to resemble a transmission system, with the corresponding implications of increased fault current and networked power flow.

For a successful smart grid , utilities must create dynamic and flexible structures to cater to the rapidly changing available technologies and applications [27]. In March of 2010, a ten-step approach to smart grids was offered by the author in [28], where the proposed steps focus on consumer involvement and accurate system modeling. The three major components for smart grid were identified as distributed intelligence, decision-making software, and digital communications [28]. Active distribution systems can be used to fulfill customer expectations with respect to reliable power and service quality, policy-driven desires for incorporating DG, and the desire for better asset management [29].

Heavy investment will be forthcoming in smart metering (projected installation of smart meters will grow from 6% to 89% by 2012 in North America), smart pricing, smart devices and in-home energy management systems, demand response, and DG [27]. Smart meters may provide some societal benefit, but benefits must be quantified by measuring service reliability improvement and ensuring that there is some sort of feedback to allow customers to act in response to their electricity use information [30]. Smart meters are part of AMI, which incorporates both automatic meter reading (one-way communication) and automatic meter management (two-way communication) [31]. Furthermore, it is imperative to identify the desired functionalities of smart meters [31].

Reference [32] discusses the use of distribution management systems (DMSs), including considerations about communication system availability, but lists many different technologies that could be used for the communication system. The idea of a DMS began by expanding functionalities of transmission-level supervisory control and data acquisition (SCADA) systems into the distribution system; the DMS may be used for optimal network reconfiguration, fault detection, isolation, and service restoration, as well as load modeling and estimation [33].

1.4.2 Distribution system engineering

The electric power distribution system comprises lower system voltages, i.e., 35 kV class and below. The distribution system begins with a substation fed from the sub-transmission system and comprises all feeders that originate, usually radially, from the substation [34]. Reference [34] describes specific aspects of distribution system design and analysis, such as the modeling of distribution system components which comprise feeders, transformers, and loads, as well as power flow techniques and short circuit studies. Feeders are usually sectionalized via normally open switches on tie-lines to improve reliability and have many laterals, which could be either single phase or three-phase [35]. Distribution system reconfiguration problems normally consider opening and closing system tie-lines to improve various aspects of distribution system operation, such as lowering losses, phase balancing, reliability, and locating DER.

Distribution system reconfiguration can be achieved using different types of constrained optimization methods, including heuristic approaches, analytic solutions, and stochastic procedures,

including evolutionary algorithms (EAs). Typical constraints include voltage limits, line-loading limits, and supply of loads. Most of the reconfigurations described in this section either assume a radial distribution system or constrain possible solutions to those that have radial topologies.

Heuristic methods such as direct ascent [36], sequential with branch exchange [37], sequential [38], and minimal tree search [39] were used to minimize system losses. A decision-tree heuristic method was used in [40] to minimize losses in the presence of an aggregated DG source carrying 25% of the system load. Reference [41] depicts a heuristic technique to minimize losses and balance the load. Losses and the number of switching operations were minimized using a heuristic algorithm incorporating a decision index in [42]. In the face of switching operations, [43] explains the use of a branch exchange heuristic method to maintain the radial system topology. A heuristic branch search and breadth first method was described in [44] to minimize restoration time and maximize reliability. Heuristic methods have also been used to minimize the cost of the reconfiguration sequentially [45] and to minimize the operating costs in a microgrid scenario [46]. Reference [47] uses a spanning tree heuristic approach to minimize the risk that a utility will have to pay quality of service reimbursements, comparing the outcomes of using average values versus using probabilistic values for component reliability.

The analytic method of polynomial time partitioning was used in [48] to minimize investment cost and maximize reliability depending on faults. Integer interior point programming was used in [49] to minimize switching operations in the context of service restoration and load balancing. In [50], an analytic approach of linear programming with a stepping stone approximation was compared to heuristic methods to reduce losses. It was found that the heuristic method performed better than the analytic approach [50]. An analytic approach was taken to maximize the benefits of DG, combining power cost, loss reduction, and reliability into a single cost function in [51].

Stochastic procedures include EAs, genetic algorithms (GAs), tabu search, ant colony optimization (ACO), particle swarm optimization (PSO) and simulated annealing (SA) [52]. Researchers have used EAs to maximize DG participation and system loadability [53], to minimize losses, bus voltage deviation, and the number of switching operations, while maximizing branch capacity [54], and to minimize losses, bus voltage deviations, and maximize transformer loading using a fuzzy representation [55]. ACO, combined with artificial immune system methods, was used to minimize losses and improve load balancing in [56]. PSO methods were used in [57] to maximize DG output.

SA, combined with an epsilon-constraint approach, was used in [58] to minimize losses and maximize system loadability. Annealed local search techniques were applied to maximize reliability in [59] and additionally to minimize the system restoration time in [60]. Parallel SA was used to maximize reliability and minimize losses in [61]. EAs with a spanning forest representation minimized loss, planning costs, and restoration time in [62]. GAs have been used in the distribution system

reconfiguration problem to minimize losses [63], minimize the costs of system DGs [64], and (with a fuzzy representation) to maximize loadability [65]. Reference [66] discusses the use of custom operators for selection and crossover to specifically adapt the GA to the problem of minimizing losses while maintaining radial solutions without electrical islands. A modified GA-heuristic algorithm was used in [67] to obtain optimal DG placements with and without islanded operation. The work in [67] also considered DG placement with feeder upgrades, such as line, switch, and transformer upgrades, without changing the existing feeder topology.

Local integrated resource planning (LIRP) began in the 1990s with the purpose of deferring transmission and generation investments under electricity market deregulation [68]. Investment deferment is achieved using a combination of consumer-focused changes, such as load control, DG and distributed storage (DS), energy efficiency improvements, and alternate rate structures, such as time-of-use pricing [68]. With similar outlook to the SGI with respect to the incorporation of distributed assets, LIRP may be used as a guide to certain distribution system design problems under the SGI.

As discussed in [69], Hydro-Quebec used planned islanding as a method to increase reliability in an area that needed extensive feeder repair. The planned island comprised a DG source and four different studies were completed to ensure the ability of the islanded system to support the load: 1) protection, 2) stability, 3) flicker, and 4) disconnection [69]. Many of these studies are required for distribution system planning in general, but are beyond the scope of the studies in this report.

Optimization techniques have also been used for system planning; reference [70] critically examines ten recent studies in multi-objective optimization used for distribution system planning. In [71], analytic hierarchy process (AHP) was used to optimize LIRP on a feeder-to-feeder basis to incorporate demand side management and DG in order to decrease costs. AHP was specifically used to balance the quantitative and qualitative aspects of the problem, including a customer preference survey [71]. Reference [72] provides an overview of several optimization methods used in the distribution planning problem of optimally locate substations and feeders to supply loads, under certain operating constraints. The authors propose the use of Bender's decomposition and fuzzy representations to solve the problem in the face of uncertainty; then, the results obtained using other optimization algorithms, including GAs, tabu search, SA, ACO, and mixed integer linear programming are compared [72].

The integration of DG into distribution system is addressed by the IEEE Standard 1547 [4], with a related standard on test conformance procedures [73] and a proposed standard dealing with intentionally islanded systems [74]. An overview of protection system issues arising from DG integration in primary and secondary distribution networks is supplied in [75]. Protection considerations are beyond the scope of the work in this report. Another investigation into the effects of DG interconnection is described in [76], where the authors explored the impacts of DG during abnormal system conditions. In [77], the author

completes several interconnection studies with respect to voltage flicker, injected harmonics, and steady-state voltage variations. An overview of the salient points regarding DG interconnection and power quality is given in [78].

The ultimate goal of the distribution system is to supply power to the consumer. To accomplish this with as few outages as possible is the purpose of reliability studies. The use of the term *reliability* is described as the amount of time that consumers are without power for an extended period of time, usually 1 to 5 minutes, and describes some common reliability indices, such as average system availability index (ASAI) [78]. Reference [79] describes techniques for evaluating reliability of engineering systems, as well as the mathematical foundations. This analysis is expanded to the practice of power system reliability analysis in [80].

None of the approaches described so far include a consideration of a non-traditional distribution system reconfiguration approach, such as the one described in this report: the addition of system feeders to maximize the utility of RE resource-based DGs in a legacy radial distribution system that is islanded. The optimization procedures used in this work fall into the deterministic and the stochastic categories, as shown in Fig. 1.1, whose organization was reproduced from [52], but modified to show where the specific algorithms used in this report fall.

1.5 Organization of report

This report is focused on the distribution design problem of adding additional feeders to improve reliability in a system with known DG participants. The distribution systems considered in this work are expected to be developing as smart distribution systems, whose elements were defined using a survey circulated among members of the electric power industry. Chapter 2 begins by discussing the design of the survey, the collection of responses, the results, and their applicability to present and future work.

Chapter 3 considers distribution system planning and modeling. Sections 3.1-3.3 will discuss reliability evaluation, the modeling of RE sources, and the feeder addition problem. The feeder addition problem will be presented in two ways: as a single objective optimization problem, and as a multi-objective optimization problem. A heuristic algorithm developed from sequential methods will be described as a way to solve the problem, followed by a discussion on the use of a GA.

The fourth chapter delves into the use of the heuristic algorithm and genetic algorithm on two different test systems, the Simplified Three-Feeder (3FDR) and the Roy Billinton Test System (RBTS). It also discusses the software tools used to complete these analyses. Chapter 5 finishes with the conclusions found from both the survey and the distribution design problem, as well as discussing the possible trajectories of future work.
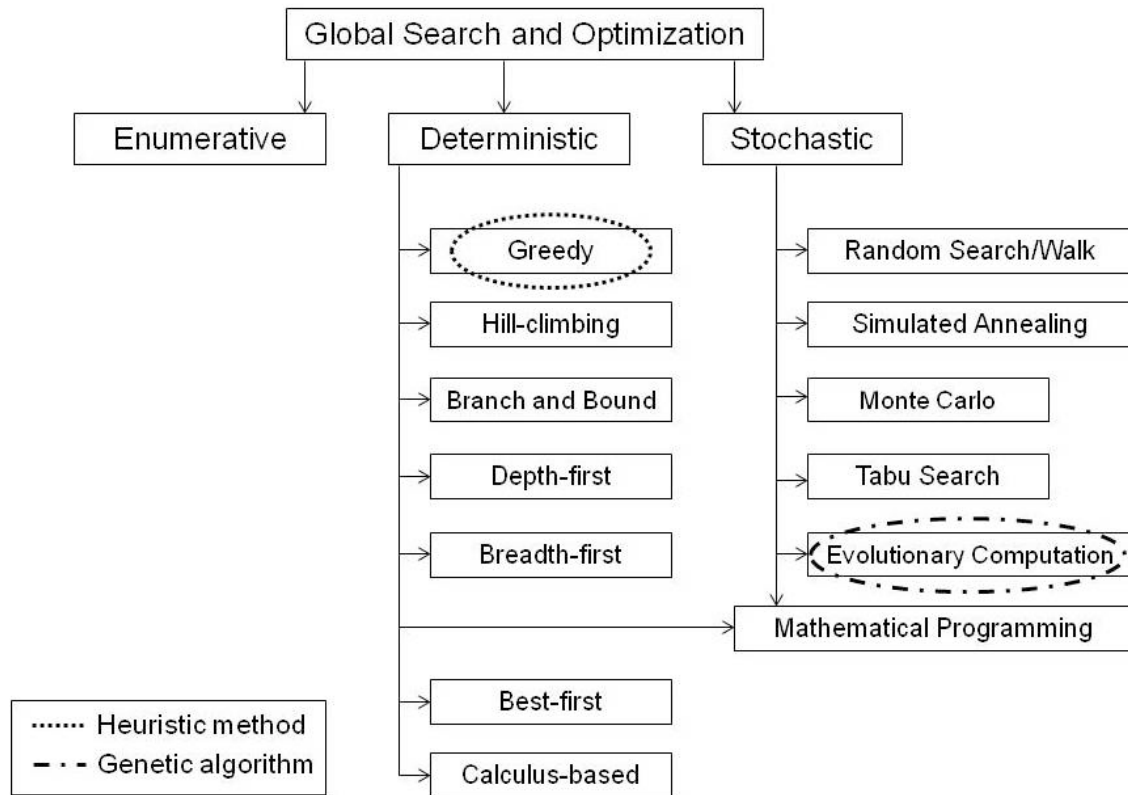
Figure 1.1. A chart of optimization approaches, reproduced from [52], to show what types of optimization approaches are used for the design of networked distribution systems. The figure was modified to show where the optimization procedures used in this report. The heuristic method, genetic algorithm, and optimization formulation are discussed in Chapter 3.

CHAPTER 2

A SURVEY SEEKING A DEFINITION OF A
SMART DISTRIBUTION SYSTEM

As described in the introduction, the idea of a smart grid has taken root as the favored evolution for the modernized North American electric grid in the past several years. As a result of government mandates and initiatives, the electric industry is beginning to adopt specific components of a smart grid, such as smart meters for dynamic pricing [15]. Smart meters alone cannot create a smart grid if they are adopted without other system changes. Distributed intelligence must be incorporated at all levels of the electric grid to improve reliability, security, and efficiency and to truly achieve a smart grid. The present day distribution system is largely passive and radial, whereas the smart distribution system is expected to be active and networked, similar to the transmission system [3].

According to the US EAC, the smart grid is expected to have several economic and environmental benefits [15]. The electric power system is aging and investment is at an all-time low – peak-shaving and self-healing functions are expected to help defer investment into the expansion of the power grid [5, 15]. At the same time, the overall amount of outage time will be reduced through the use of automated and self-healing functions [15]. AMI will allow consumers to manage their energy usage based on their preferences regarding price or perceived environmental impact [15]. Overall system efficiency will be increased by reduction in transmission and distribution system losses as a result of peak-shaving activities [15]. The distribution system is the arena where many of these developments, such as AMI, demand response, DG, and reduced outage times, are expected to be implemented [14]; these distribution system changes will create a *smart distribution system*.

Perhaps what is desired in the overall smart grid framework is a clear perspective of industry preferences, especially for the distribution system where most of the changes will occur. One method to gain understanding of industry preferences is by inquiring into the nature of those preferences. Pacific Crest Mosaic completed a survey of industry preferences with respect to smart grid in July 2009 [17]. Federal work contemporaneous to and completed following the SGI has defined expectations about the implementation of the smart grid and any exploration of smart distribution systems must take this work into account. However, a specific definition of a smart distribution system is lacking at this time. Thus, a survey to define a smart distribution system was designed to study the implications of the SGI on distribution engineering [81]. The ten points of the SGI, mentioned in the first chapter in Section 1.4.1,

were used as a guide to the organization and content of the survey. The three primary objectives of this survey are:

    i.   to provide a definition of a smart distribution system from the perspective of the industry,

    ii.   to identify existing tools from transmission engineering that can be applied at the distribution level, and

    iii.   to guide investigation into the technical requirements and implications of a smart distribution system.

The survey was circulated among potential respondents in North America, including members of industry and academia. This chapter presents the motivation and methods used in the design of this survey, as well as the results and their applicability.

The survey described in this chapter was used as a reference for the Colorado Governor's Energy Office (GEO) survey on the existing smart grid programs among the state's utilities in May 2009 [25]. The GEO survey was circulated to the 57 utilities in Colorado to establish the relative maturity of each utility's smart grid adoption plan. Additionally, the GEO survey aimed to identify gaps in communications, metering, and grid-automation infrastructure that could be addressed as part of a joint grant application for ARRA09 funds.

This chapter is a result of several publications; Section 2.1 reproduces material from [82] © 2009 IEEE, while Sections 2.2-4 are summarized in [83]. Additional information used in this chapter is available in [84].

2.1 Design of the survey

The overall power system architecture is the focus of much federal work on the smart gird [2, 13]; however, to achieve the expected benefits of a smart grid as defined in EISA07, it is important to determine the defining characteristics of smart distribution. Smart metering and AMI is considered the first step toward smart distribution and many utilities have started (or completed) extensive smart meter rollouts [18-24]. But, there may be significant ambiguities in defining the next steps.

Smartness may be incorporated into the electric distribution system through implementing demand response; installing communications infrastructure; deploying sensors throughout the electric grid; introducing more DER; and establishing locations capable of utility-planned islanding – the above list is by no means exhaustive. To establish an overall coherent and consistent framework for adoption and implementation of the distribution-level smart grid necessitates some determination of the relative importance of the different qualities of smartness and their enabling technologies. Hence, a survey to determine the characteristics of a smart distribution system was created.

The SGI in Title XIII of EISA07 was used as a general definition of the *ideal* smart grid. By examining the SGI through the lens of distribution engineering, the following eight philosophies of the smart grid were identified: DER and peak-shaving; demand response; self-healing; sensing; consumer devices; optimizing distributed assets; islanding; and advanced tools. These eight philosophies (as shown in Fig. 2.1) became the eight sections of the survey. Certain sections had small amounts of overlap, due to the interconnected nature of the benefits and characteristics of the smart grid. Repeatable questions were placed only in the first category that appeared to participants. A complete copy of the survey text, as distributed, is presented in Appendix I. The survey design will be described for each of the eight philosophies in the remainder of this section. The first question of the survey asked participants to rank the eight areas of smart distribution relative to one another.

2.1.1 DER and peak-shaving

The definition of DER used in this survey comprises DS and DG, from both conventional technologies and RE resources. An example of the composition of DER is shown in Fig. 2.2. Questions were asked specifically about each of these components of DER in order to achieve a more nuanced view of the expectations of DER. To begin this section, the survey requested participants to specify which distribution voltage class is preferred for the integration of DER – 120 V, 480 V, 5 kV class, 15 kV class, or 35 kV class, as illustrated on a logarithmic scale in Fig. 2.3.
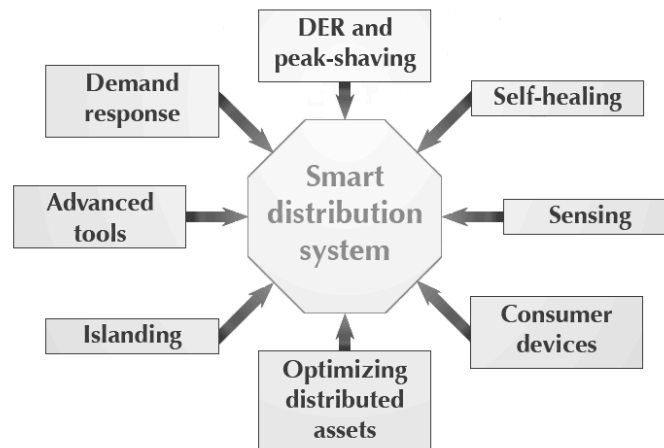
Figure 2.1. Eight philosophies of smart distribution, adapted from the SGI. Reproduced from [82] © 2009 IEEE.

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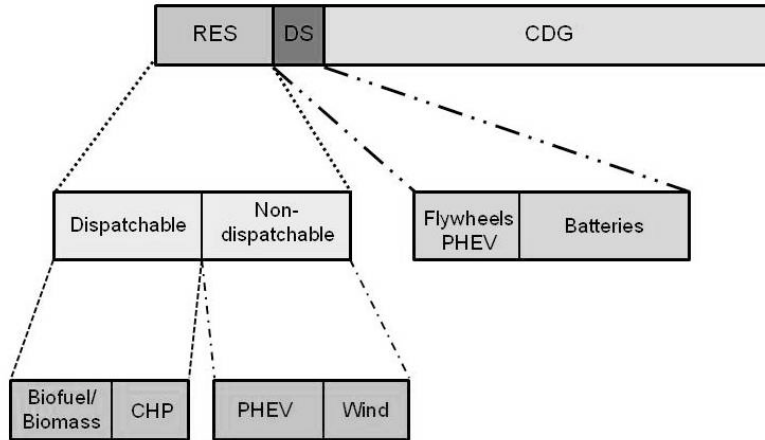
Figure 2.2. An example of the different components of DER. Types of conventional DG sources include reciprocating engines. This image should not be considered as an exhaustive list.
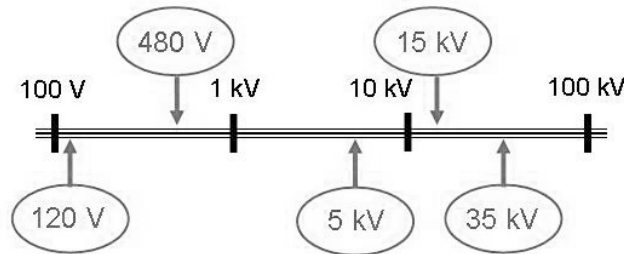
Figure 2.3. Voltage classes for distribution systems, shown on a logarithmic scale. Reproduced from [82] © 2009 IEEE

The existing penetration of DG is considered "low", comprising only 3% of all grid-connected generation [13]. Furthermore, it is anticipated that few system disruptions will be caused by DG until the penetration level reaches 15% of all grid-connected generation [3]. The focus on DG in the smart grid, however, is to incorporate RE resources. Most state renewable portfolio standards (RPSs) require that between 10% and 30% of total electricity sales come from renewable sources by 2030 [85].

Certain RE resources such as wind and solar are inherently variable and non-dispatchable while others like geothermal and hydro are dispatchable and not as prone to variability. At the distribution level, non-dispatchable and variable RE resources pose a series of technical considerations. The survey addressed these considerations through questions related to

i.   the expected overall penetration of RE resources, based on state RPSs,

ii.   the overall percentage of DG that would be comprised of RE resources,

iii.   the preferred methods of dealing with non-dispatchability, and

iv.   the preferred RE resource technologies and desired smart functionalities.

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With respect to DS, it is important to know the expected percentage of non-dispatchable DG that will be supported by DS and the favored storage technologies.

Determining how DER should be managed in the distribution system is important to the creation of adequate support systems, such as software functionality and communications. Two theoretical entities were used to describe the configuration of the local DER management system: a commercially-operated distribution management system (CDMS) and a local energy management system (LEMS). The CDMS corresponds to feeder-level management software and is operated by a commercial entity; whether that entity is a utility or a third party is not considered within the scope of this survey. The LEMS corresponds to load-level management software and it is operated by the consumer.

The survey offered four management possibilities as shown in Fig. 2.4. The first management possibility (A) is one-to-one management of DER through the smart meter; this option has direct communication with the utility energy management system (EMS). The second option (B) uses a feeder-level CDMS for intermediary management of DER between the smart meter and the utility EMS. The third option (C) manages DER on-site using a LEMS on the customer-side of the smart meter, which directly communicates with the utility EMS. The fourth option (D) utilizes both a LEMS for on-site management and a CDMS as an intermediary manager between the smart meter and the utility EMS. In all four schemes, the smart meter (abbreviated 'SM' in the figure) acts as the gateway between the consumer and the grid. The smart meter location is commonly known as the PCC. The control and design of smart distribution will depend on the expected management topologies.

How communication will take place in the smart grid has not yet been determined [17]. Respondents of this survey were asked to identify a preferred communication structure out of four different possibilities as shown in Fig. 2.5. The first option (A) is two-way communication between DER and the smart meter and two-way communication between the smart meter and the utility. The second option (B) is the same as (A), but with the added ability for DER to communicate amongst themselves. The third option (C) is analogous to the first (A), but with the addition of two-way communication with the LEMS. The fourth option (D) is equivalent to the second option (B) combined with two-way communications with the LEMS. Additionally, the survey asked participants to identify preferred communication methods out of seven communication technologies that could be used: cellular protocols, WiFi, wireless mesh networks, Zigbee, internet protocols, BPL, and fiber-optic.
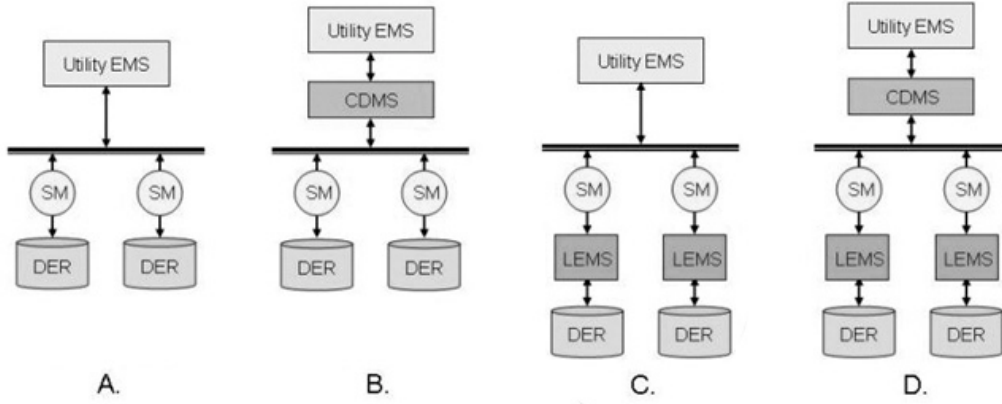
Figure 2.4. Different management structures for DER systems. The smart meter is denoted as 'SM'. Reproduced from [82] © 2009 IEEE.
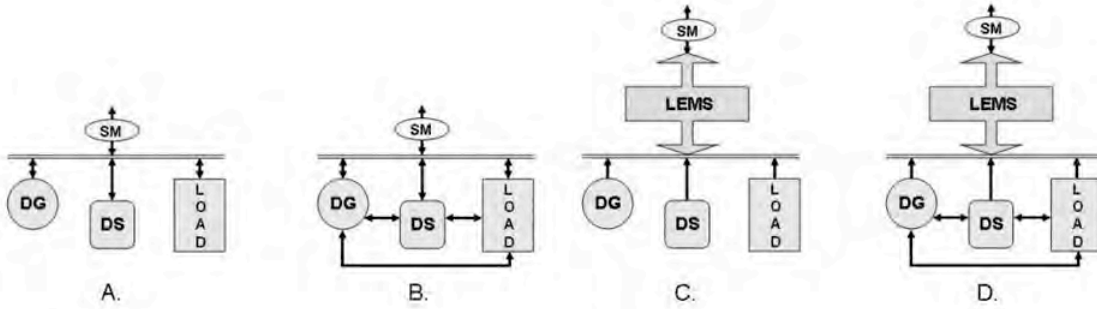
Figure 2.5. Possible communication paths for DER, arrows denote channels of communication. Reproduced from [82] © 2009 IEEE.

To determine how DER use will be regulated in the ideal smart distribution system, participants were asked to choose between advance scheduling, real-time scheduling, and flexible scheduling. Advance scheduling includes day-ahead scheduling and beyond (e.g. month-ahead), while real-time scheduling includes any scheduling done near real-time (e.g. hour-ahead or 15 min-ahead). Flexible scheduling would allow any combination of advance scheduling or real-time scheduling. The survey also asked respondents to identify which entity among the utility, the CDMS, and the LEMS should be allowed to schedule DER: the utility, the CDMS, or the LEMS. Viable limits of DER usage could be contractual, conditional, or unrestricted. Contractual scheduling corresponds to penalties levied against the controlling entity if the schedule is not maintained. Conditional scheduling means that utilities may approve or deny short-term DER scheduling changes.

Examples of smart technologies important to the integration of DER were determined by a 2008 EAC report on smart grids [15]. Participants were asked to choose which technologies enable the perceived benefits, the successful integration, and optimal operation of DER. Technologies identified by the EAC include automated adaptive relaying and microprocessor-based feeder automation with communication capability.

One of the main benefits of DER is the potential to engage in peak-shaving operations; however, DER is not the only technology for achieving peak-shaving. Peak-shaving could be implemented based on dynamic pricing of electricity or the time when electricity is used and could be achieved through smart appliances, load control, and utility-planned islanding. The survey asked participants to rank the non-DER forms of peak-shaving strategies and identify how quickly those strategies should be able to engage. References [8], [14], [76] and [86, 87] were used to draft the questions in this section of the survey.

2.1.2   Demand response

Demand response, as defined by [88], is "the reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructures optimization or deferral". There are several smart functions that enable consumers to actively participate in demand response, such as dynamic pricing, load control, and DER dispatch. Different options for dynamic pricing include real-time pricing, interval pricing, time-of-use pricing, and critical peak pricing.

The survey asked respondents to identify the amount of control a utility should have over the demand response activities of the consumer. The choices are that consumers should have:

i.   *No control at the meter*, the customer controls small loads (less than 3 kVA) and the utility controls everything else, including smart appliances.

ii.   *Very limited control at the meter*, the customer controls loads, including smart appliances, and the utility controls DER.

iii.   *Limited control at the meter*, customer controls real power supplied by the DER, loads, energy demand, automated controls for smart appliances, DER demand response, and market participation through supply of ancillary services.

iv.   *Total control at the meter of utility-approved installations*, the customer controls the ability to island, and all the options of controls listed under 'limited control at the meter'.

The nature of demand response would be very different if the utility had primary control or if the utility had no control. The question of centralized versus distributed control is important for the operation of smart distribution systems.

AMI, programmable consumer devices (or smart appliances), LEMS software to enable consumers to self-manage, building/facility EMS interfaced with market signals, smart appliances interfaced with the utility system, and distribution state estimators are all technologies that could enable demand response, and the survey respondents were asked about the best options. Participants were asked to identify the timeframe for "useful" demand response: within subcycles, within one cycle, within

several cycles, within minutes, or within one hour. References [10] and [88] were used to create questions for this section of the survey.

2.1.3   Self-healing

One of the required functions of the smart grid, overall, is that it be self-healing [3], [6], [13], and [89]. However, the distribution-level approach to self-healing may differ from that of the transmission system. Four modes of self-healing are preventative, corrective, emergency, and restorative [89]. Respondents were asked to rank the above functions of self-healing, as they should be implemented at the distribution level.

Common reliability indices may be used to quantify the self-healing ability of the distribution system. The ASAI is one such index and is defined as the ratio of *customer hours service availability* to *customer hours service demand* [78]. Overall, the current system ASAI is estimated to be 0.999375 [78], or "3 nines" [15]. The survey asked participants what the target ASAI was in a smart distribution system – ranging from 4 nines (0.9999) up to 6 nines (0.999999). The survey also asked how quickly self-healing mechanisms should be activated at the distribution level and how quickly self-healing actions should be achieved post-activation. These timeframes can be visualized as a matrix of overall response time as illustrated by Fig. 2.6, where the different shaded blocks represent different overall times for self-healing based on the contributions of activation time and recovery time.

Perceivably, three different areas in a smart distribution system could be responsible for self-healing functions: operations centers, smart substations, or smart feeders [15]. The survey asked participants to rank these choices relatively and the corresponding smart functions that would enable that location to respond in a self-healing manner to system disturbances. Smart functions included at operations centers could be distribution state estimators, broad area distribution management systems, and dynamic system topology models, to name a few. Technologies that would add smarts to feeder and distribution automation include feeder condition monitoring and communication-enabled voltage regulators. References [31], and [89-91] were used to construct questions for this section of the survey.

2.1.4   Sensing

A major component of self-healing and real-time monitoring of the distribution system is the widespread deployment of smart sensors and smart meters. The expected voltage level at which smart sensors should be deployed will affect the types of information available to the utility such as direction and amounts of power flow, locations and usage patterns of DER, notification of DER energizing the system, and existing protection settings based on system impedance.

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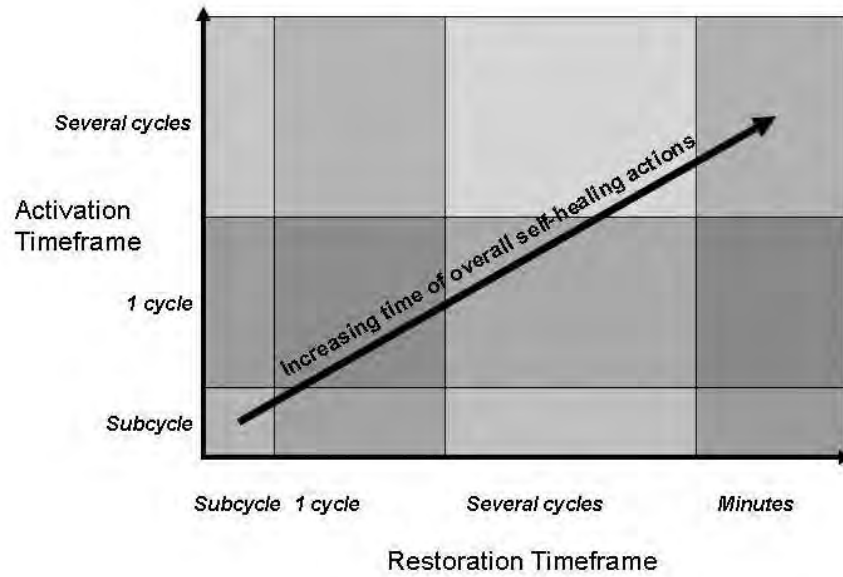
Figure 2.6. Matrix of self-healing timeframes. The total recovery time is just the addition of the activation timeframe and the restoration timeframe. Different shadings denote different self-healing time milieus. Axes are not to scale. Reproduced from [82] © 2009 IEEE.

With respect to real-time monitoring, the survey asks participants to identify the timeframe which they consider to be "real-time" for sensing and smart meters. Certain transmission level sensors have not yet been applied at distribution level; other sensors have only limited applications in the distribution system. The survey asked participants to identify which sensors could have an increased presence for distribution-level monitoring [92, 93].

At the time of writing this report, massive deployment of smart meters has begun; advanced meters comprise as much as 52.9% of the metering infrastructure in Pennsylvania [27]. Recently, ARRA09 awards for smart grid projects will fund the installation of at least 18 million smart meters [17], [94]. However, there is still no overall consensus on what exactly a smart meter should *do* besides receiving dynamic pricing and measuring net energy usage [31]. A smart meter could potentially control DER, monitor power quality, profile the incoming (or outgoing, if bi-directional power flow is enabled) current and voltage, detect tampering, and log local events, among many others [95, 96]. Survey participants were asked to identify all the desired functionalities of a smart meter, regardless of whether existing smart meters have that functionality yet. The potential functions of a smart meter, including some options among the listed functions, are listed in Table 2.2 (created using [95, 96]). Additionally, [97-100] were used to create questions for this section of the survey.

Table 2.1

List of sensors (created using [28, 29]). Reproduced from [82] © 2009 IEEE.

Types of Sensors
Giant magnetoresistance (GMR)
Optical (e.g. Faraday effect)
Phasor measurement units (PMU)
Digital sensors with incorporated intelligence
Thermal
Shock
Hall effect
Satellite
Mechanical
Chemical
Video
Photo

2.1.5   Consumer devices

Smart appliances, which are a type of consumer device, may come in many varieties – programmable devices, thermal devices, and devices that have smart circuits. Programmable devices allow the user to control the device schedule in advance. Thermal devices could be coupled with dual-mode combined heat and power (CHP) in the consumer's building. An example of a smart circuit device is one in which the device stays "off" until it is "pinged". Survey participants were asked to identify the preferred smart appliance technology, as well as their preferred smart appliance functionality. Smart appliances could have two different types of smart functionality: two-way communication and/or control algorithms set by the smart meter. The control system for a smart appliance could be located on the appliance itself; as part of the LEMS; through smart metering; or through a demand response/ load control program.

2.1.6   Optimizing distributed assets

The adoption of smart technologies (beyond smart meters) could be hastened by certain product philosophies such as plug-and-play methodology, standardized services, and regulatory adjustments. Survey participants were asked to rank the order of importance of each of the above mentioned product philosophies. The smart grid is anticipated to allow the development of new products, new services, and new markets. Respondents to the survey had the opportunity to identify distribution-level products, services, and markets. Examples of conceivable new services included power quality on demand and

planning services; an example of a new market that could be opened by smart distribution is ancillary services. Also, participants were asked to select the smart technologies that will best enable the adoption of a smart distribution system, such as intelligent network feedbacks and AMI.

Table 2.2
Smart meter functionality ([95, 96]). Reproduced from [82] © 2009 IEEE.

Function	Smart Meter Function		
	Option 1	*Option 2*	*Option 3*
Communication	Two-way communication with utility	Two-way communication with other devices, such as DER or CDMS/LEMS	
Reads	On-demand	Scheduled	Real-time
Automation	Automatic registration	Time synchronization	
Alarms	Tamper detection	Power quality monitoring and alarms	Outage and restoration alarms
Profiling	Current	Voltage	Demand, load, and generation
Scheduling	Schedule and bid for system activity	Store and download time-of-use schedules	
Control	DER	Interpret system economic information	
Miscellaneous	Event logging	Ability to measure bi-directional power flow	

Other distribution system changes could help enable the new products, services, and markets, but are not explicitly part of the smart grid. Examples of these changes include meshed distribution, increased penetration of CHP, and DER-related developments, such as advanced battery storage technologies. The survey addressed these tangential changes, as well as areas of further optimization to ensure the success of a smart distribution system. Examples of areas for further optimization include networked connections between feeders and networked connections among all assets at the distribution level, and devices with two-way communication for reporting and control, whether by the utility or the CDMS/LEMS.

2.1.7   Islanding

Islanding refers to the electrical separation of a certain portion of the grid, possibly comprising loads and DER, from the area electric power system (EPS). This change from the grid-tied mode to and islanded mode may be accompanied by the operation of the island independent of the grid. The smart grid is expected to be able to sustain islanded sections, where the ability to island is intended to improve reliability and security of supply [13]. However, the preferred voltage level at which islanding occurs

needs to be identified. The survey asked participants to identify a voltage level at which the ability to island should be incorporated.

Respondents were also asked how control of islanding ability should be handled. Smart functions and technologies that would enable islanding are also addressed in the survey. Examples of these functions and technologies include power flow monitoring within an island; island identification; and smart interconnection switches with communication capabilities. References [7], [9], and [74] were used to build questions considering the ability to island.

2.1.8 *Advanced tools*

In the existing smart grid literature, most cited advanced tools are related to transmission-level monitoring and analysis [13], [89]. Advanced tools are those intended to streamline routine operations, through increased visualization, analysis, and simulation. However, many DMS functions exist independently of one another [33]. In the future, these separate functionalities may be combined and expanded to enable the smart distribution system to operate effectively. The survey asked respondents to identify the desired functionalities of a smart DMS.

Furthermore, to enable a smart DMS, different data storage techniques will be required, as well as a substantial investment in communications infrastructure. In the survey, participants identified the different types of data stored (Critical; Useful; Other), and the desired location of data storage. The selected data storage location has implications for responsibility of data management.

This section concludes the description of the survey design. The next section will discuss the dispersion of the survey and the collection of responses.

2.2 Dispersion of the survey and collection of responses

The survey was hosted in the public domain by an independent internet service at *Survey Gizmo* [101]. An online venue was chosen so that the anonymity of the participants could be maintained with the intention of encouraging candid responses. The only required identification from volunteers was their affiliation, whether they belonged to industry, academia, or a national lab. Although the intended survey audience was members of the electric power industry, the survey was also circulated to members of academe and national labs in order to determine if there were any differences between the industry definition and other definitions.

The dispensed survey had 67 questions, which, as described in Section 2.1, were divided into eight sections based on eight philosophies of a smart distribution system. The responses to all questions were completed using the following inputs:

      i.   *single-select* (using radio buttons),

ii. *multi-select* (using check boxes), or

iii. *prioritized ranking* (using movable arrows).

All questions included a text box denoted as the *Other:* selection so that recipients could express their own views, if different from the choices given.

The survey was open for participation for a period of seven months, from March 2009 until October 2009. Initially, the survey was released as a complete document, with a sentence in the introduction to encourage partial participation. However, initial responses indicated that partial participation was not occurring. To encourage partial participation, the survey was split into four sub-surveys, grouped by related topics with less than 20 questions: DER penetration and technologies; communication and sensing; consumer participation and demand response; and network operations. Splitting the original survey into four sub-surveys effectively encouraged partial participation – for some questions, as many as one third of the total responses came from the split version of the survey.

The survey was distributed to members of the electric power industry by email, using popular listservs, such as POWER-GLOBE [102]. Participation was also advertised at various conferences attended by the survey authors, including the 2009 IEEE Power and Energy Society General Meeting and the PSERC Industry Advisory Board meeting in May 2009, where posters on the survey design was presented during the poster sessions. Participants were volunteers from North America.

2.3 Results

The results for different types of survey questions will be represented in different ways. The results of all single-select questions will be presented in a pie chart. Multi-select question results will be shown in bar graphs. Questions that required ranking will be presented as box plots, which will be explained below. Survey participation reached 31 respondents in seven months, based on the required introductory questions. The Pacific Crest Mosaic Smart Grid survey completed in July 2009 had 20 participants [17]. Approximately 75% of the smart distribution survey participants identified their affiliation as "Industry", with job titles such as "Manager of Smart Grid Technology Planning", "Consulting Engineer", "Partner", "Electrical Engineer", and "Business Manager". Less than 15% of respondents identified their affiliation as "Academia".

When asked to rank the eight attributes of a smart distribution system relative to one another, the average (AV) ranks given by participants to the options are shown in Table 2.3, as well as the standard deviation (SD) of each response. A table with the AV ranks and SDs of the options will be provided with all ranking questions. There were 31 responses to this question; the number of responses to a question will be denoted as *N*, which may be thought of as the sample size. A rank of 1 is interpreted as "most important" and a rank of 8 is interpreted as "least important". From Table 2.3 it is observed that

respondents seek to optimize distributed assets and incorporate DER as central aspects of a *smart distribution system*, while the ability to island ranks as least important. The remaining survey results will be presented in order of relative importance given by the results in Table 2.3.

Table 2.3
Relative rankings of the attributes of a smart distribution system. A rank of '1' is the most important, while a rank of '8' is the least important.

Attribute of a smart distribution system	Rank	
	AV	*SD*
Optimizing distributed assets	3.32	2.29
Incorporating DER	3.65	1.92
Integration of massively deployed sensors and smart meters	3.90	2.20
Active participation by consumers in demand response	4.23	2.19
Adaptive and self-healing technologies	4.35	2.12
Advanced tools	4.77	2.09
Integration of smart appliances and consumer devices	5.58	1.82
Islanding ability	6.19	2.40
N = 31		

The results shown in Table 2.3 can also be expressed as a box plot which depicts the spread of the choice of rankings among the individual choices. The corresponding box plot is shown Fig. 2.7. A box plot depicts several items of statistical importance, such as the first quartile, third quartile, and median [103]. In the box plots shown in this report, the lower line on the box corresponds to the first quartile, the upper line corresponds to the third quartile, and the median, which happens to be the second quartile, is the line through the middle of the box [103]. The "whiskers" that spread up and down represent the lowest value within the 1.5 interquartile range [103]; outliers beyond this range are represented with a '+'. Any asterisk shown on the line of the box plot represents the mean.
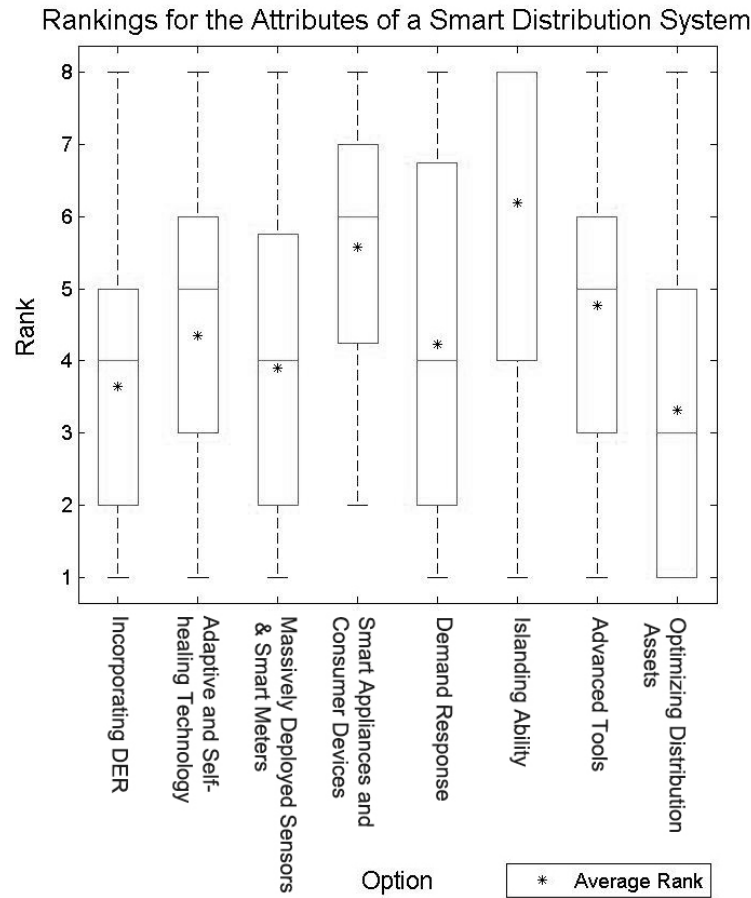
Figure 2.7. Box plot of the rankings of the options presented in Table 1. A rank of '1' is the most important, while a rank of '8' is the least important. (*N = 31*)

Fig. 2.7 provides a visualization of the spread or variance of the option rankings and also indicates the absence of outliers in the individual rankings of the attributes of a smart distribution system. Fig. 2.8 presents a histogram of the individual responses for "islanding ability". From the histogram, it is seen that 16 respondents ranked the ability to island as the least important (rank 8), while the remaining 15 respondents ranked the ability to island as increasingly important. This distribution of rankings causes the median line to overlap with the line for the third quartile in the box plot of Fig. 2.7. The purpose of the in-depth analysis of the response statistics of islanding ability is to explain the statistical implications of the box plot and highlight the fact that most participants thought that the ability to island is the least important aspect of a smart distribution system.
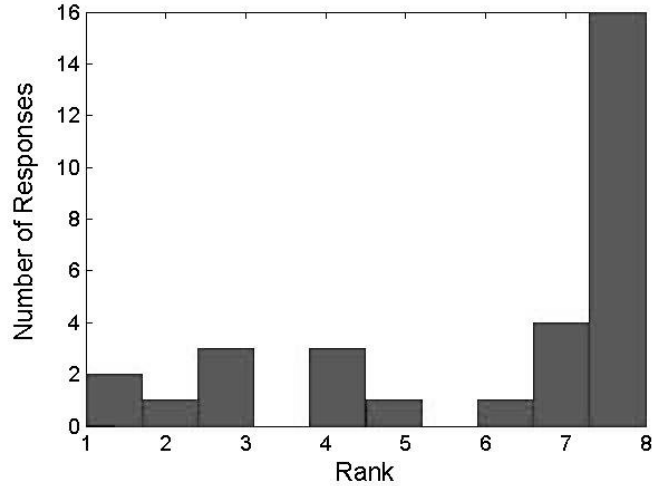
Figure 2.8. Histogram of the responses for the importance of the ability to island, from Table 2.3. Rank 1 is the most important, rank 8 is the least important. (*N = 31*)

2.3.1   *Optimizing distributed assets results*

New products, services, and markets could be used to ease incorporation of the smart paradigm into the distribution system. For example, survey participants identified plug-and-play methodology (or interoperability), standardized services, and easy upgrades as three product philosophies that would enable adoption of a smart distribution system (see Fig. 2.9 and Table 2.4). Smart distribution is expected to open markets for services such as smart grid-tailored devices, planning services, and software tools for advanced energy management such as LEMS (see Fig. 2.10).

Participants identified several new markets opened by a *smart distribution system* – ancillary services, managing energy for the consumer, power quality on demand, and (again) smart grid-tailored devices, shown in Fig. 2.11. The top three "smart" technologies to enable new products, services, and markets were real-time pricing or time-of-use pricing, smart metering infrastructure, and demand response/ load management programs (see Fig. 2.12 and Table 2.5). As seen in Fig. 2.13, other changes to enable the optimization of distributed assets include DER developments, custom power devices, and networked/meshed distribution topology.

Two areas needing further optimization include two-way communicating devices and networked connections between feeders (shown in Fig. 2.14 and Table 2.6). Respondents expected that condition-based monitoring and maintenance, advanced outage avoidance and management, and transformer load management would help to optimize asset utilization and efficient operation (see Fig. 2.15).
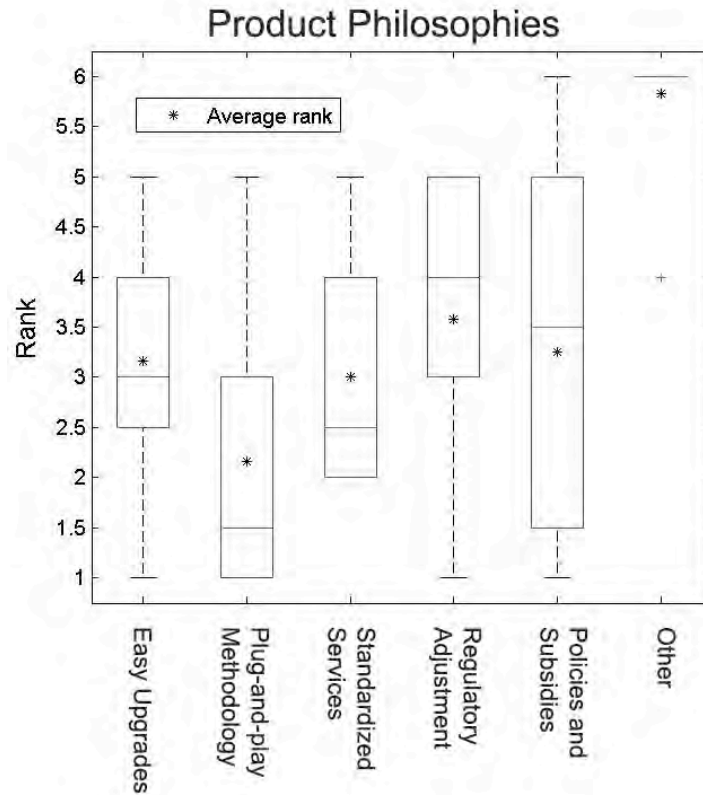
Figure 2.9. Box plot of the ranking of product philosophies expected to contribute to the adoption of a smart distribution system. The "Policies and Subsidies" option had the greatest range of responses. "Plug-and-play Methodology" is clearly the most important to respondents. A rank of '1' is the most important, while a rank of '6' is the least important. ($N = 12$)

Table 2.4
Relative rankings of product philosophies to contribute to the adoption of a smart distribution system. A rank of '1' is the most important, while a rank of '6' is the least important. These results are also presented in Fig. 2.9.

Product philosophy	Rank	
	AV	*SD*
Easy upgrades	3.17	1.19
Plug-and-play methodology	2.17	1.53
Standardized services	3.00	1.13
Regulatory adjustment	3.58	1.44
Policies and subsidies	3.25	1.82
Other ✓ *Government regulation should not drive any deployment*	5.83	0.58
N = 12		

New Services in Smart Distribution Systems
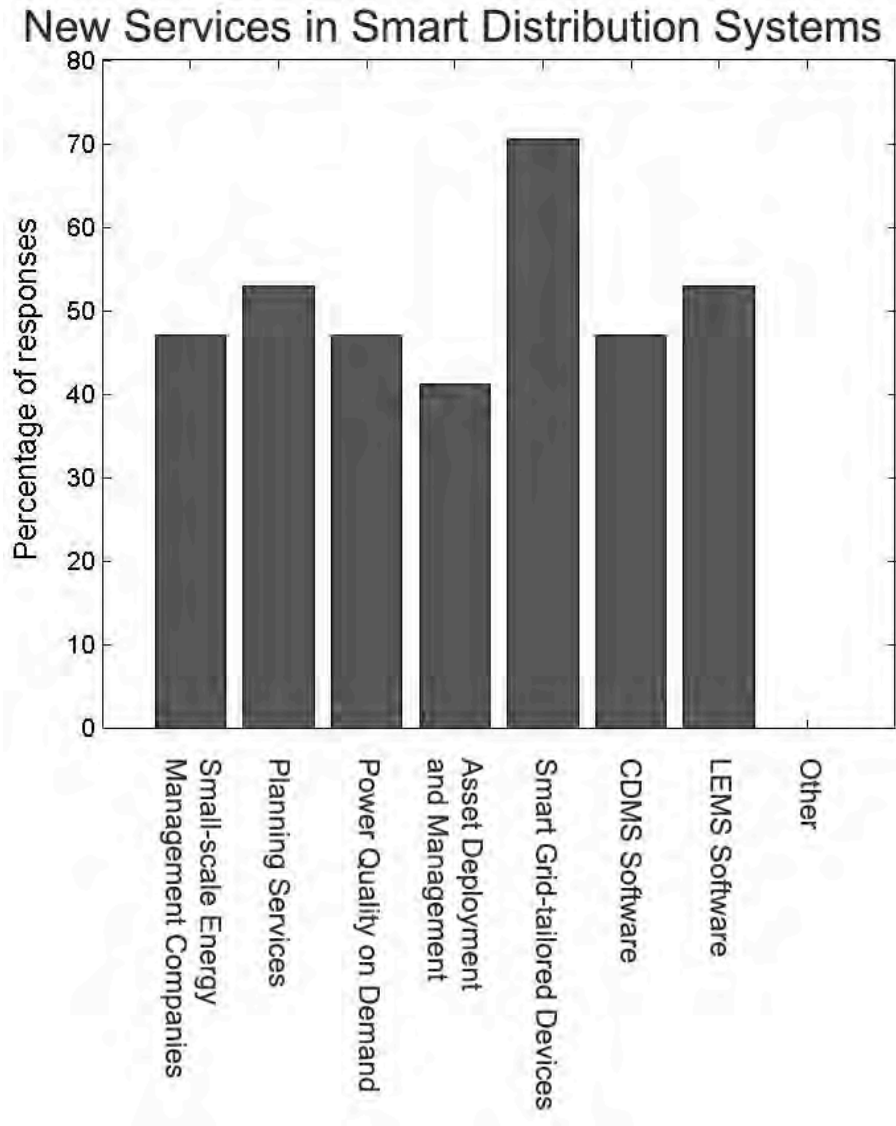
Figure 2.10. Percentage of responses to the multi-select question regarding which new services would be opened up by the adoption of a smart distribution system. ($N = 17$)

2.3.2   *DER and peak-shaving results*

Almost 40% of the survey questions dealt with incorporating DER while enabling peak-shaving technologies. To review, DER in the survey document includes DS and RE resources. Respondents expressed that DER integration should be allowed at all distribution voltages, from 120 V to the 35 kV class (see Fig. 2.16). Seventy two percent of question respondents identified the most important *smart* quality for DER as two-way communication capabilities (see Fig. 2.17).
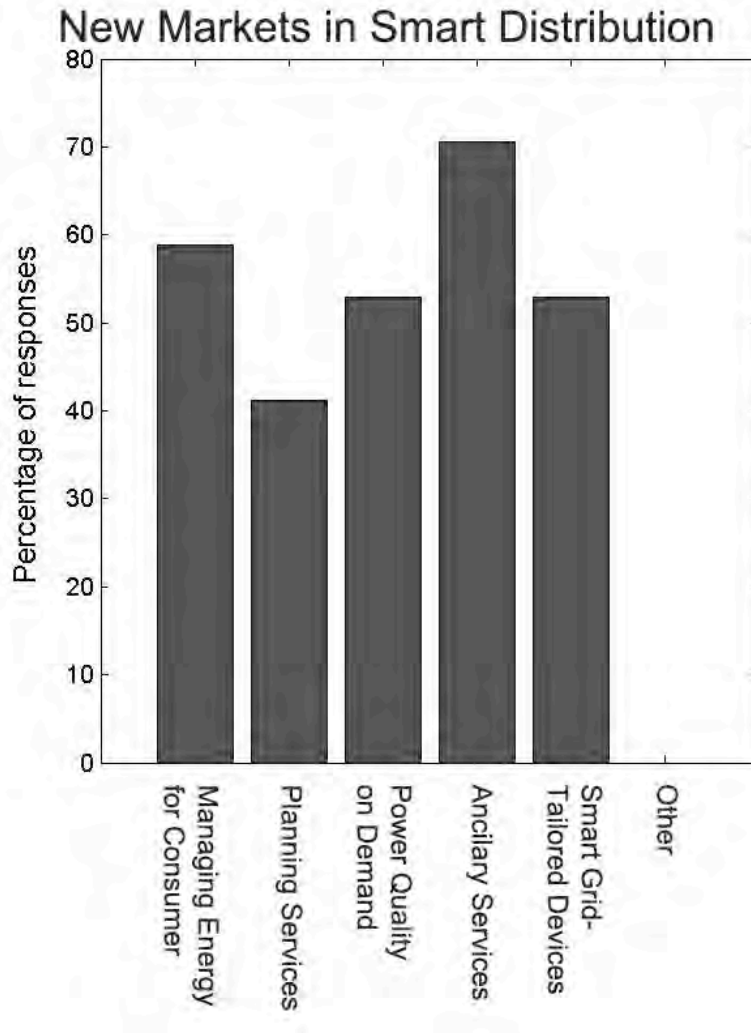
Figure 2.11. Percentages of multi-select answers regarding new markets expected to open to utilities with the adoption of a smart distribution system. (*N* = 17)

Regarding the management of DER, participants selected options that had large degrees of local control. Fig. 2.18 depicts the top management selections identified by 21 respondents, which were options C and D (circled). These options both had the LEMS controlling local DER. Option D included the feeder level CDMS before connecting to the utility's EMS. The percentages of the chosen options are shown in Fig. 2.19. Local communication options were "all" or "nothing" comparatively; the top two options were: 1) two-way communications between the smart meter and the DER, and 2) and a combination including two-way communications between the smart meter and the LEMS, two-way communications between the smart meter and the two-way communications between the DER and the LEMS, and two-way communications between individual DER units. These options are shown in Fig. 2.20, while the percentages of responses are shown in Fig. 2.21.
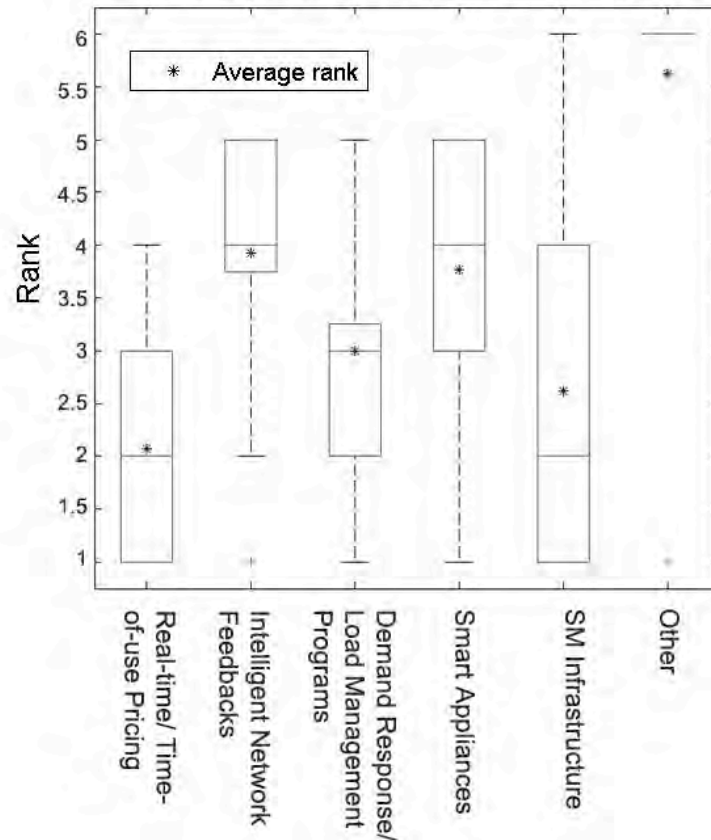
Figure 2.12. A box plot of the rankings of smart technologies considered the most important for enabling new products, services, and markets by survey respondents. A rank of '1' is the most important, while a rank of '6' is the least important. (*N* = 13)

Table 2.5
Relative rankings of smart technologies considered the most important for enabling new products, services, and markets by survey respondents. A rank of '1' is the most important, while a rank of '6' is the least important. These results are also presented in Fig. 2.12.

Smart technology	Rank	
	AV	*SD*
Real-time or time-of-use pricing options design and research	2.08	1.12
Applying intelligent network feedbacks and consumer responses to make a new market system	3.92	1.26
Demand response/ load management program	3.00	1.15
Smart appliances interfaced with Smart Grid system	3.77	1.30
Smart metering infrastructure	2.62	1.66
Other ✓ *Again, this will require some experience*	5.62	1.39
N = 13		

31
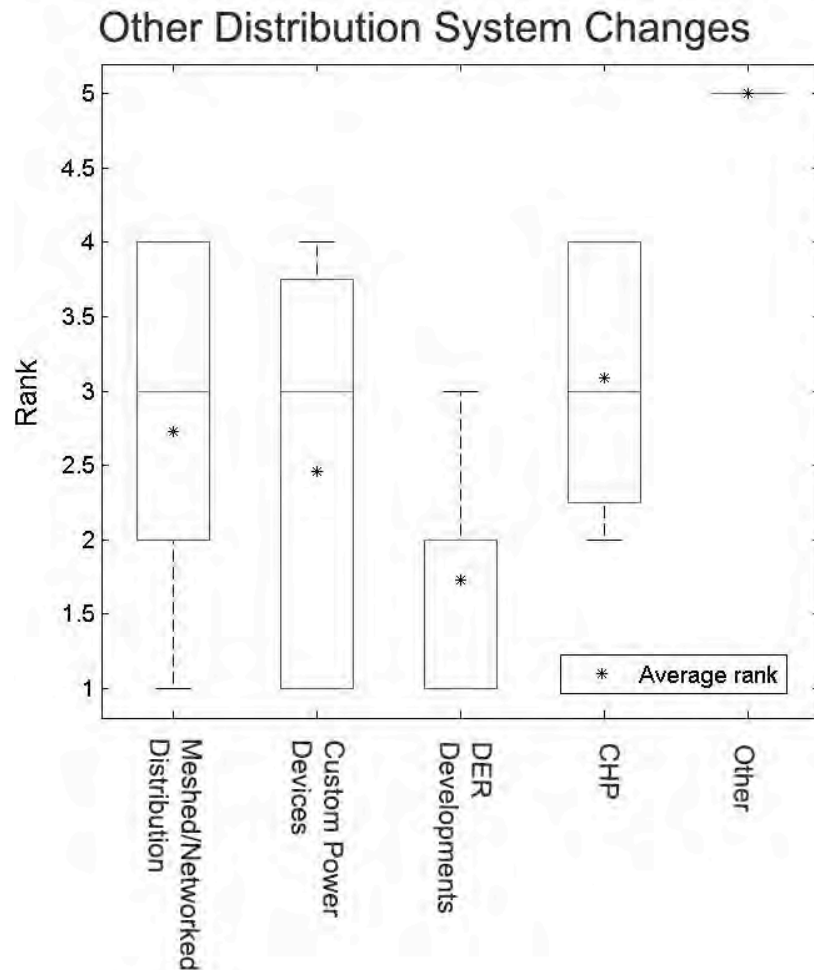
Figure 2.13. A box plot of other distribution system changes expected to enable new products, services, and markets. "DER Developments" are ranked the highest. A rank of '1' is the most important, while a rank of '5' is the least important. ($N = 11$)

Table 2.6
Relative rankings of other distribution system changes expected to enable new products, services, and markets. A rank of '1' is the most important, while a rank of '5' is the least important. These results are also presented in Fig. 2.13.

Distribution system change	Rank	
	AV	*SD*
Meshed/networked distribution	2.73	1.19
Custom power devices	2.45	1.29
DER developments	1.73	0.79
CHP	3.09	0.83
Other	5.00	0.00
N = 11		
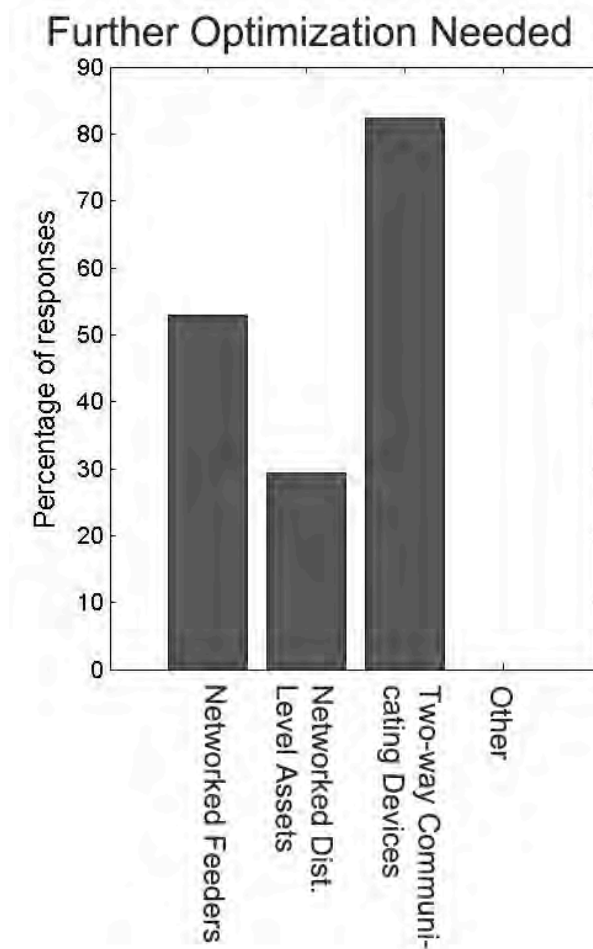
Figure 2.14. Aspects of the distribution system that need further optimization, according to survey respondents, to ensure successful operation of a smart distribution system. Most participants thought that "Two-way communicating devices" were important, followed by "Networked feeders". ($N = 17$)

A question asking participants to identify the percentage of total generation expected to be met via RE resources was prefaced by the fact that most state RPSs range from 15-20% of electricity sales from renewable energy by 2030 and include hydroelectric generation [85]. The overall response to this question was that participants expected 10-19% of generation to be met via a combination of dispatchable and non-dispatchable RE resources (see Fig. 2.22). However, some participants responded "*none, RPS causes uneconomic investment*" and "*I don't think that there should be a mandate, such as is implied in the wording of the question*". In general, participants expected no more than 50% of new DER to be comprised of RE resources (see Fig. 2.23). To deal with the non-dispatchability of some RE resources, respondents gave the ranks in Table 2.7, which shows that the top response was to combine non-dispatchable RE resources with a combination of fast-starting dispatchable generation sources. The same information is represented using a box plot in Fig. 2.24, to present the previously outlined statistical measures of the ranking. The first quartile lines overlap the median lines of "Incorporate Different Types

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of DS" and "Combine Non-dispatchable RE resources with Fast-starting Generation", respectively; the third quartile of "Incorporate Bulk Storage at Transmission Level" overlaps its own median line. The top-rated RE technologies were photovoltaics, biofuels and biomass, CHP/waste heat, and wind (shown in Fig. 2.25 and Table 2.8). The "smart" functionality necessary to achieve the desired level of RE resources penetration was the ability to store non-dispatchable energy for later use (shown in Fig. 2.26 and Table 2.9).
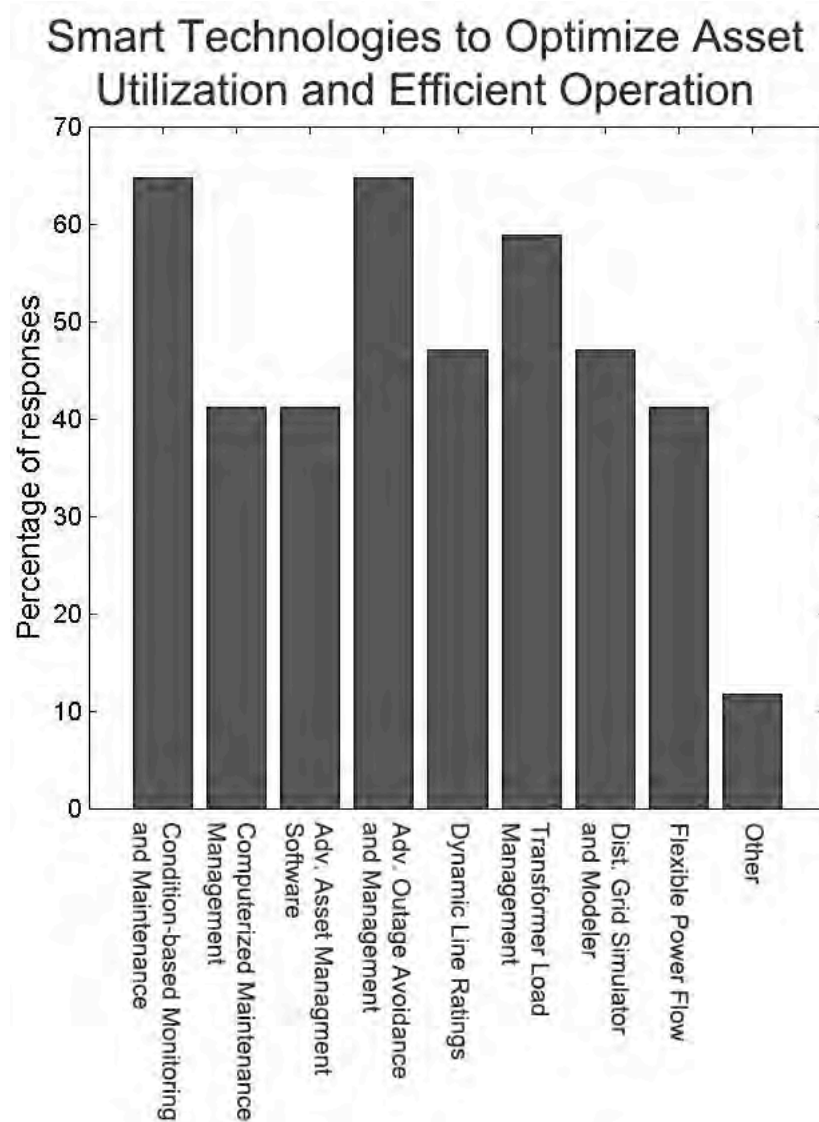
Figure 2.15. Percentages of responses considering which smart technologies would help to optimize asset utilization and efficient operation. The "Other" responses were "the technologies that provide the most benefit" and "real time pricing". ($N = 17$)

Voltage Level of DER Integration
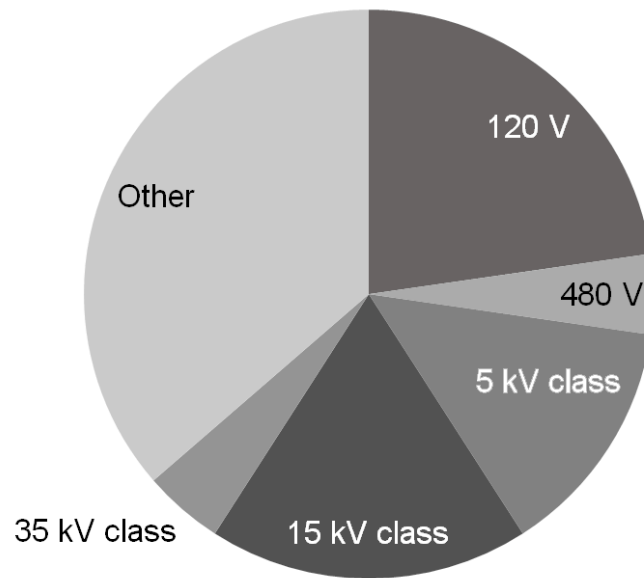
Figure 2.16. The response percentages to where DER should be allowed in the distribution system. Four out of 8 "Other" responses were some variation on "*All of the above*"; the remaining "Other" responses were "*Service voltages*", "*Depends on the economics of the particular DER,*" "*A range from 120 V to 12 kV*", and "*240 V*". ($N = 22$)

Desired Smart Qualities in DER
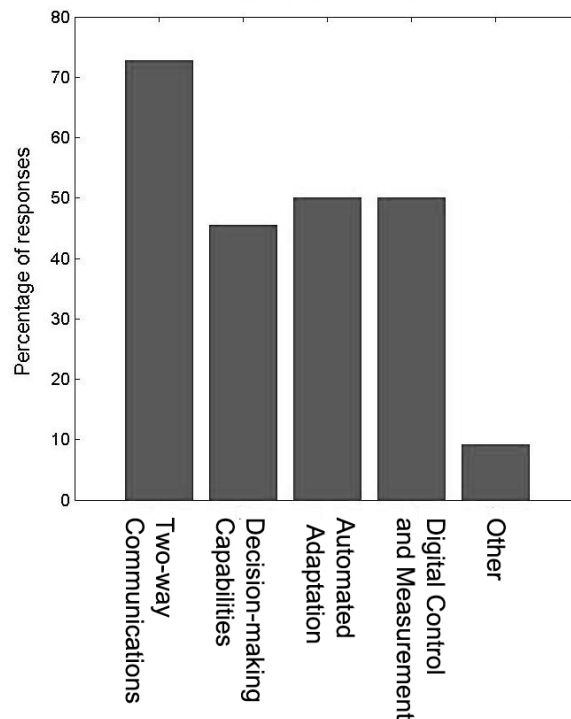
Figure 2.17. Responses regarding the desired smart qualities in DER. The "Other" responses were "*All of the above*", "*Under frequency disconnect and reconnect*". ($N = 22$)
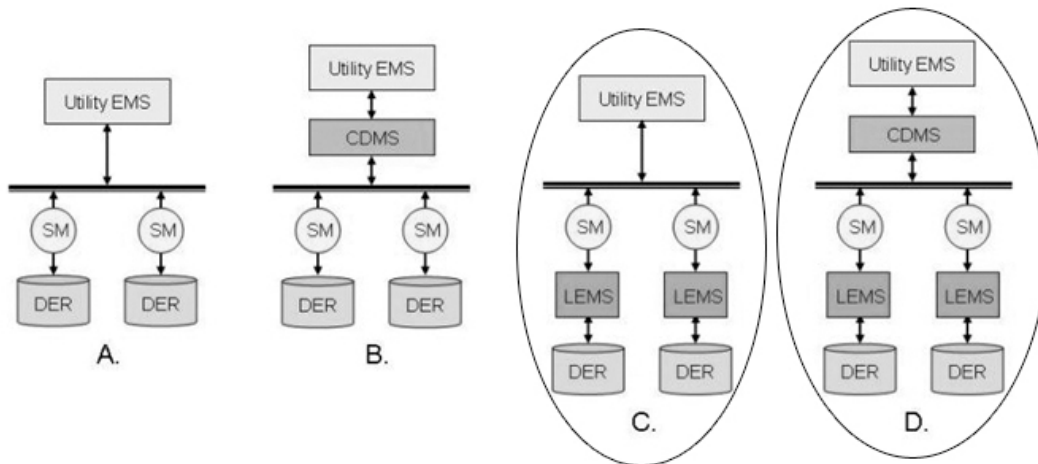
Figure 2.18. DER management in a smart distribution system. The favored two options are circled. Figure sans circles reproduced from [82] © 2009 IEEE. The percentages of responses are shown in Fig. 2.19. (*N* = 21)
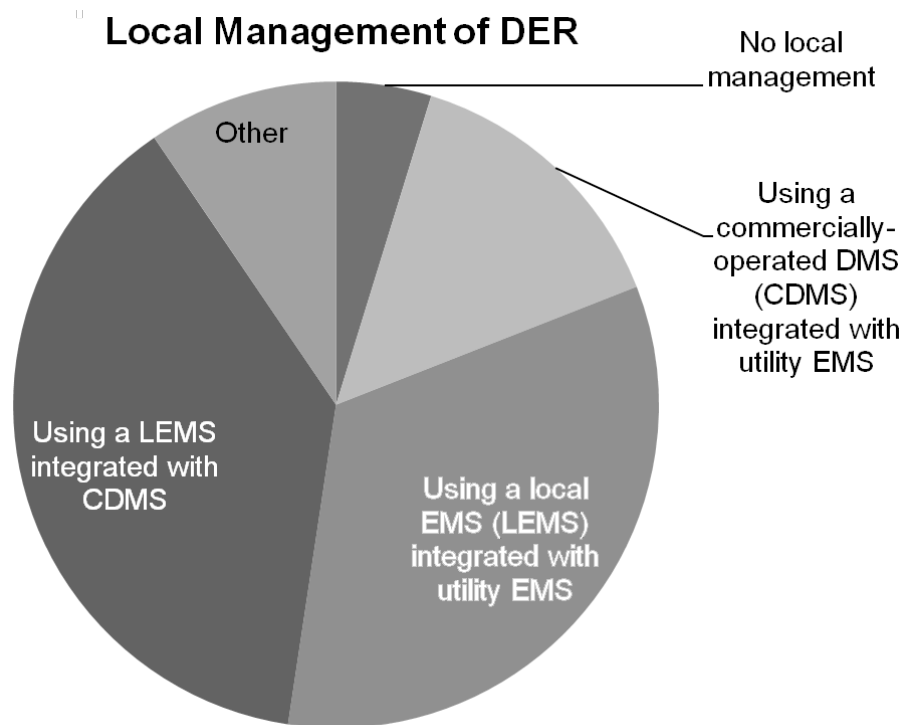
Figure 2.19. Percentages of responses regarding DER management. "LEMS with Utility EMS" corresponds to option (C), while "LEMS with CDMS" corresponds to option (D) in Fig. 2.18. The "Other" responses were "*All*" and "*Every system should be allowed to operate*". (*N* = 21)
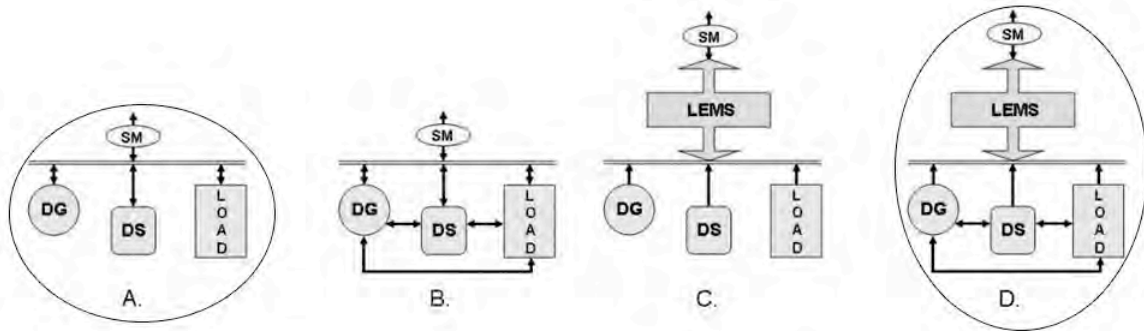
Figure 2.20. DER communications in a smart distribution system. The favored two options are circled. Figure sans circles reproduced from [82] © 2009 IEEE. The proportions of responses are shown in Fig. 2.21. ($N = 21$)
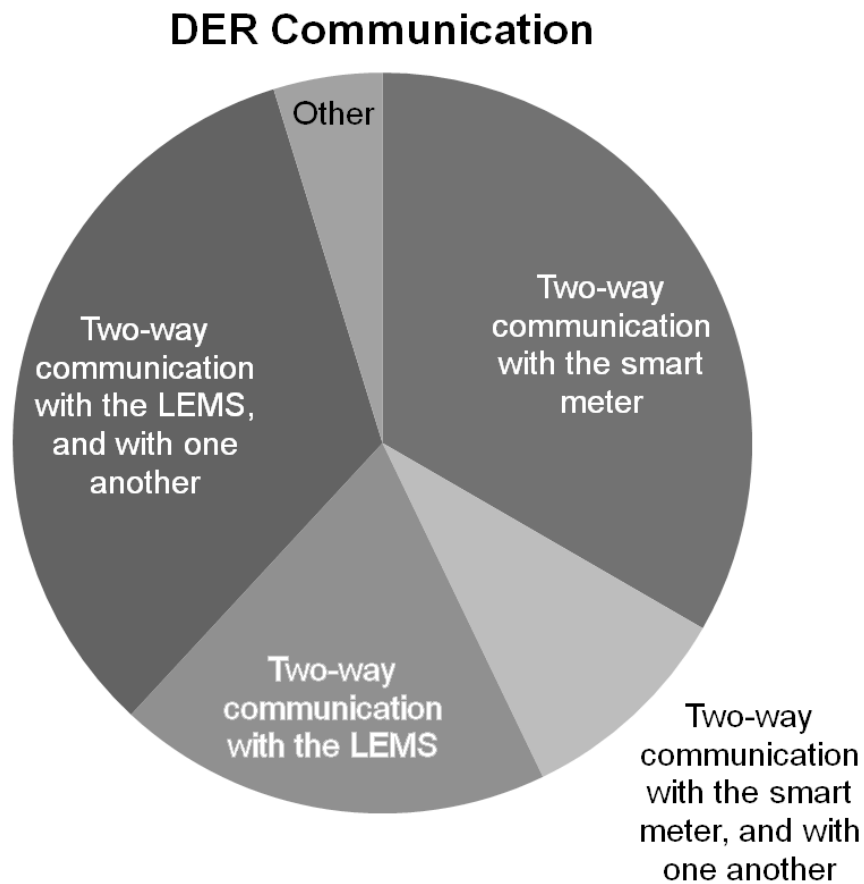
Figure 2.21. Percentages of responses considering how DER should communicate. "Two-way with utility EMS" is shown as option (A) and "Two-way with LEMS and each other" is shown as option (D) in Fig. 2.20. The "Other" response was "*All should be allowed. However there should also be a price option, where the utility presents a concurrent price for consumption and production*". ($N = 21$)

RE Resource Percent of Total Generation

Other

20-30% from combination of non-dispatchable and dispatchable sources

10-19% from combination of non-dispatchable and dispatchable sources
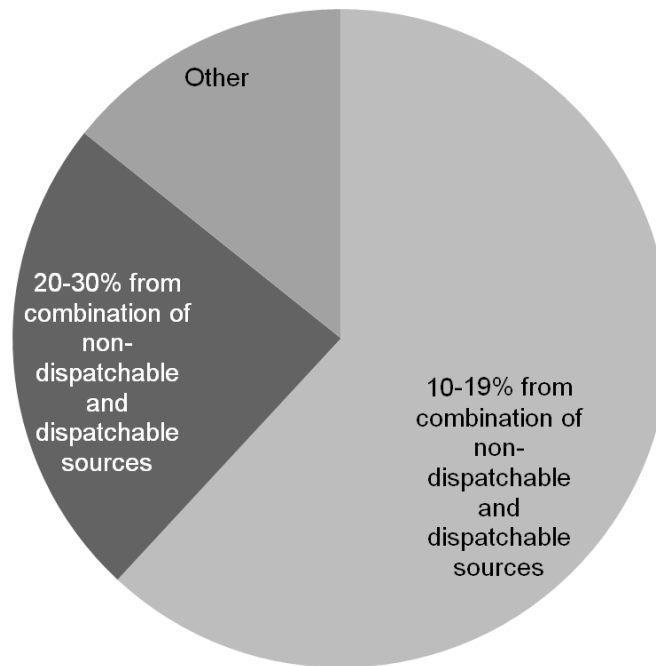
Figure 2.22. Percentages of responses asking how much of the total generation should be met via RE resources. The option of using only dispatchable resources was offered, but no respondents saw that as a viable option. However, most respondents preferred 10-19% of total generation, which is on the low side of RPS mandates. (*N*=21)

Percent New DER Met Via RE Resources

More than 75%

Less than 25%

50-75%

25-50%
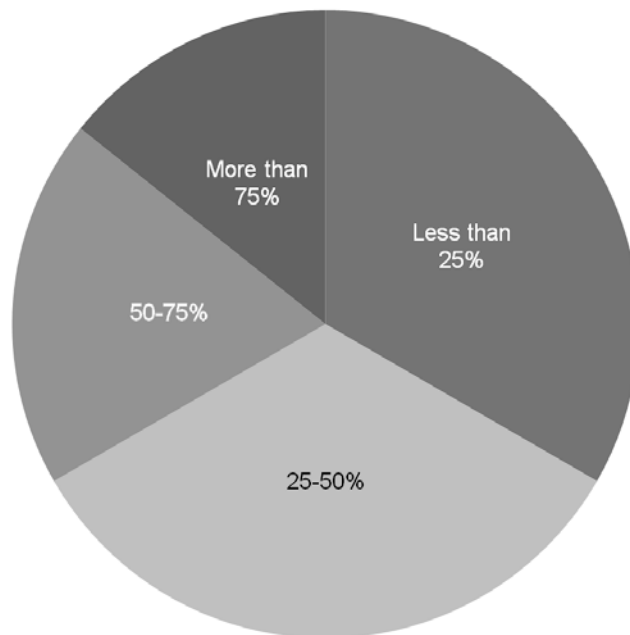
Figure 2.23. Percentages of responses considering the percentage of new DER to be met using RE resources. A majority of responses believed that less than 50% of new DER would be comprised of RE resources (*N*=21)

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Table 2.7
Relative rankings of the possible ways to deal with non-dispatchable RE resources. A rank of '1' is the
most important, while a rank of '5' is the least important.

Dealing with non-dispatchable RE resources	Rank	
	AV	*SD*
Combine non-dispatchable RE resources with fast-starting generation sources	2.19	1.51
Incorporate different types of DS	2.38	1.02
Monitor and predict conditions which cause intermittency to efficiently plan system usage	2.89	1.36
Incorporate bulk storage at the transmission level	2.94	0.68

Other
  ✓ *Provide concurrent prices to RE resources and DS to allow them to make their own economic decisions to produce, consumer, store.*
  ✓ *Storage at the distribution substation level (15 kV).*
	4.63	1.02

N = 16		

Participants were divided on the location of DS between the following choices: 1) on the consumer-side of the smart meter or 2) the utility-side of the smart meter (see Fig. 2.27). As shown in Fig. 2.28, the useful amount of DS in percentage of rated load for at least four hours [104] was identified as less than 50%. Similarly, the amount of non-dispatchable DER expected to be supported by DS was up to 50% of the device rating, as seen in Fig. 2.29. The relative rankings of the different types of storage devices are shown in Table 2.10 and Fig. 2.30 (box plot). The most popular form of storage was batteries; surprisingly, respondents ranked PHEV less favorably to flywheels as possible technologies for DS although the responses were widely spread compared to other storage technologies. In Fig. 2.30, the first quartile of "Battery Storage" overlaps the median. The third quartile lines of options "UPS", "Super-capacitors/ Ultra-capacitors", and "PHEV" overlap the lines of their respective medians.

The "smart" functionality required to enable the penetration of DS into the system was identified as "automatic charge and discharge using frequency sensors – i.e. storage units absorb excess generation and then release energy when system is over-loaded", and all responses are shown in Fig. 2.31. The most important benefit of DS is expected to be constant power output from distributed generation. However, as seen in Fig. 2.32 and Table 2.11, respondents also expected the following benefits: 1) ride-through capability during faults and outages, 2) energy reserves, 3) countering momentary power disturbances, and 4) damping price spikes in market caused by unmet electricity demand. The smart technologies

expected to enable DS are shown in Fig. 2.33, and no one technology received more than 46% of the responses.
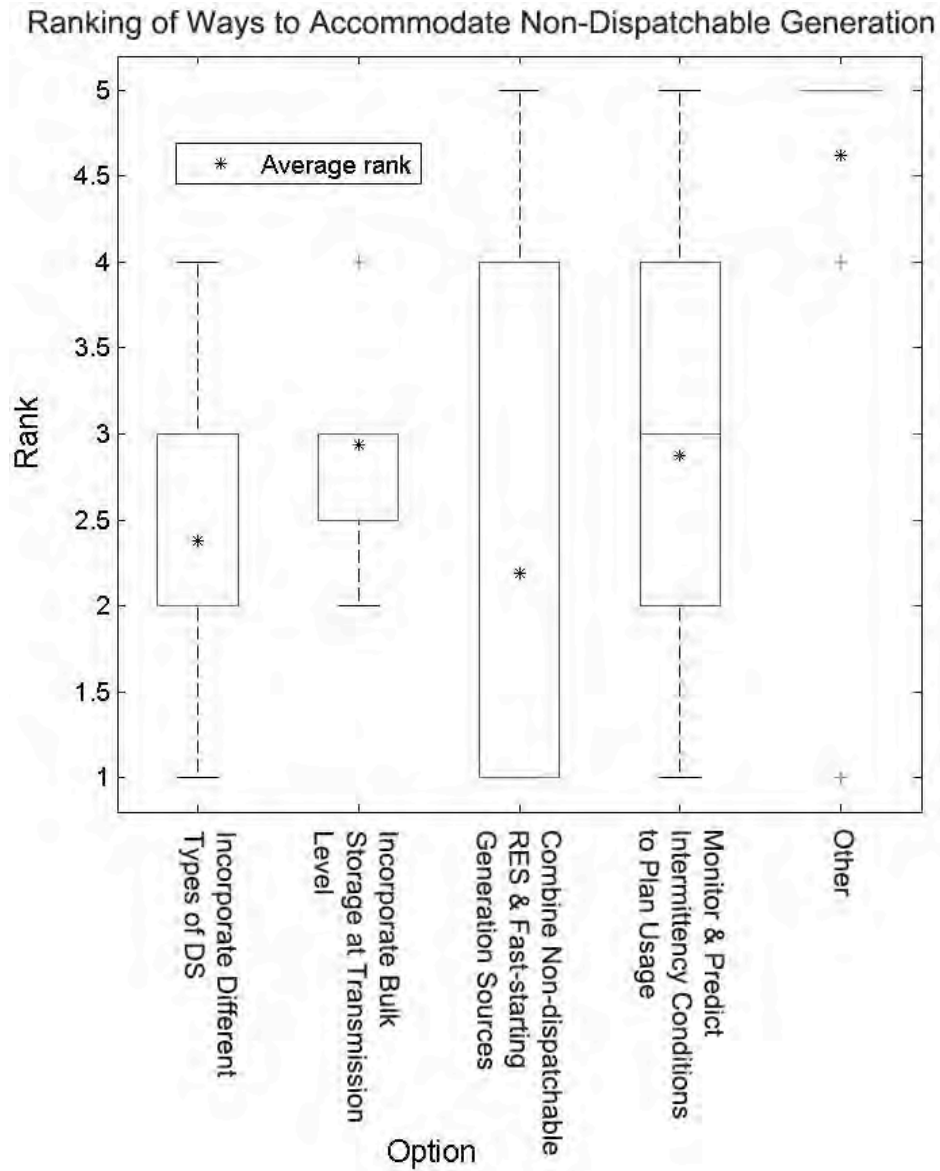
Figure 2.24. Box plot of the ranks for the possible ways to deal with non-dispatchable RE resources. "Other" responses are described in Table 2.7. A rank of '1' is the most important, while a rank of '5' is the least important. ($N = 16$)
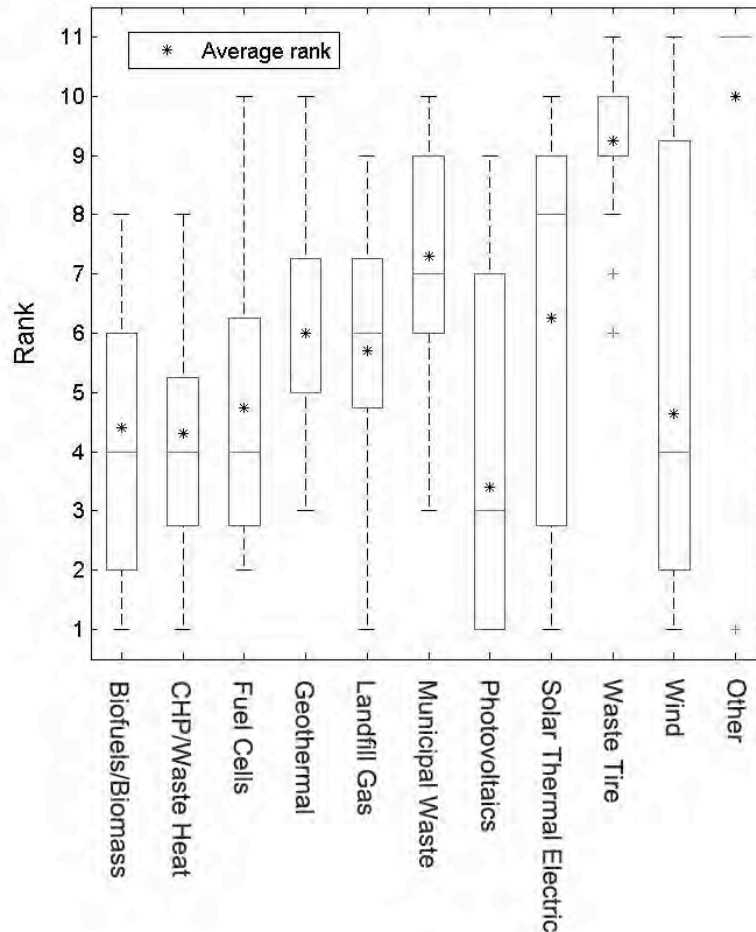
Figure 2.25. A box plot showing the ranks of different RE resources relative to one another. Wind and solar (both PV and solar thermal electric) both have large spreads on their responses, compared to most other technologies. A rank of '1' is the most important, while a rank of '11' is the least important. (N=20)

Aspects of feeder and distribution automation considered the most important to the integration of DER were identified as microprocessor-based feeder automation with communication capability and feeder condition monitoring to improve reliability, as shown in Fig. 2.34 and Table 2.12. Smart grid technologies to enable DER usages are real-time pricing and utility-initiated demand response programs (see Fig. 2.35). Respondents said that DER should be scheduled one day in advance and in real-time (see Fig. 2.36); almost 40% of respondents said that the utility should be doing the DER scheduling (see Fig. 2.37). However, as seen in Fig. 2.38, there was no consensus on DER scheduling limits: unrestricted, conditionally, or contractually.

Most participants thought that the DER should be communicating with the utility EMS at least once per minute, whether it was communicating directly or indirectly through the LEMS or CDMS (see Fig.

2.39). When asked about the communications technologies within the smart distribution system, shown in Fig. 2.40, there was no clear consensus on the preferred method from options including: cellular, WiFi, wireless mesh networks, Internet, broadband over power line, and fiber optic cables. The author feels that the area of communications technologies vis-à-vis electric distribution systems is one that could clearly use more exploration, since communications is a central principle of the SGI.
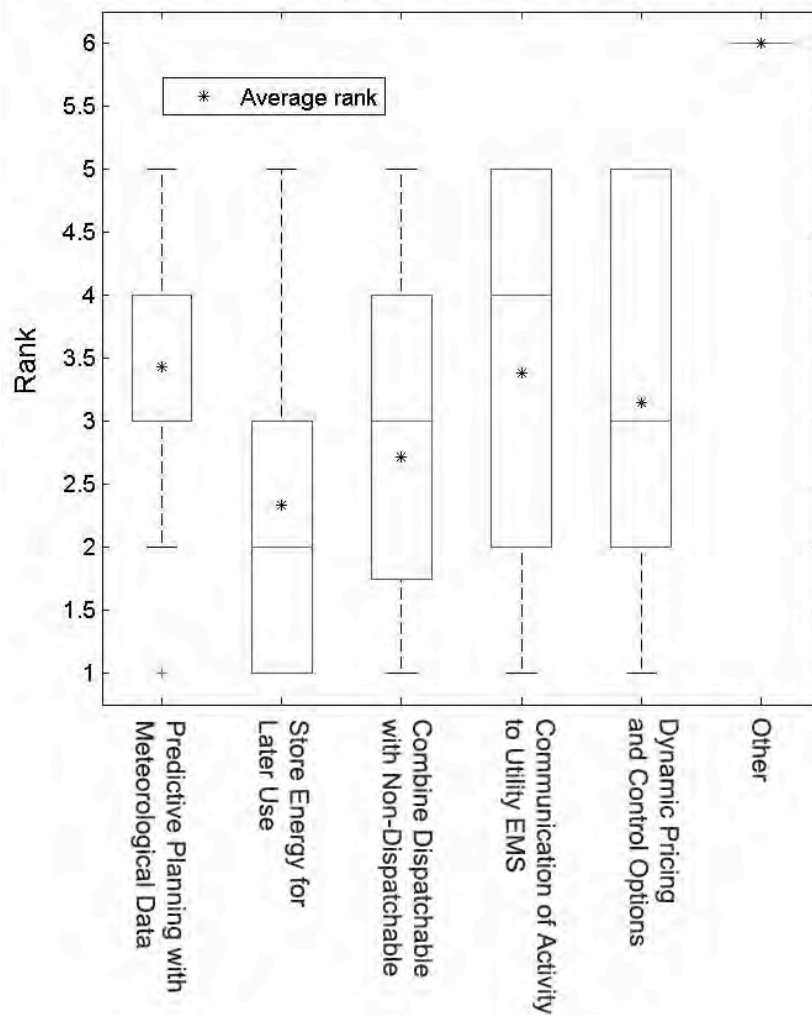
Figure 2.26. A box plot of the ranking of the smart functionalities expected to enable the participation of RE resources. A rank of '1' is the most important, while a rank of '6' is the least important. (*N*=21)

Table 2.8
Relative rankings of different RE resources. A rank of '1' is the most important, while a rank of '11' is the least important. These results are shown in a box plot in Fig. 2.25.

RE resource	Rank	
	AV	SD
Biofuels/biomass	4.24	2.10
CHP/waste heat	4.19	2.04
Fuel cells	4.67	2.50
Geothermal	5.90	1.97
Landfill gas	5.67	2.27
Municipal waste	7.24	1.76
Photovoltaics	3.57	2.99
Solar thermal electric	6.33	3.20
Waste tire	9.24	1.26
Wind	4.90	3.56
Other ✓ *The economics are generation size dependent* ✓ *Batteries and other storage devices, such as vehicle to grid*	10.08	3.01
N = 20		

Table 2.9
Relative rankings of the smart functionalities expected to enable the participation of RE resources. A rank of '1' is the most important, while a rank of '6' is the least important. These results are shown in a box plot in Fig. 2.26.

Smart function	Rank	
	AV	SD
Predictive planning using meteorological data	3.43	0.93
Ability to store non-dispatchable energy for later use	2.33	1.49
Combination systems, where a dispatchable form is paired with a non-dispatchable form to maintain constant power output	2.71	1.31
Communication with EMS to know what types of renewables are generating and what levels they are generating at	3.38	1.50
Dynamic pricing and control options for the customer	3.14	1.59
Other	6.00	0.00
N = 21		

DS Location
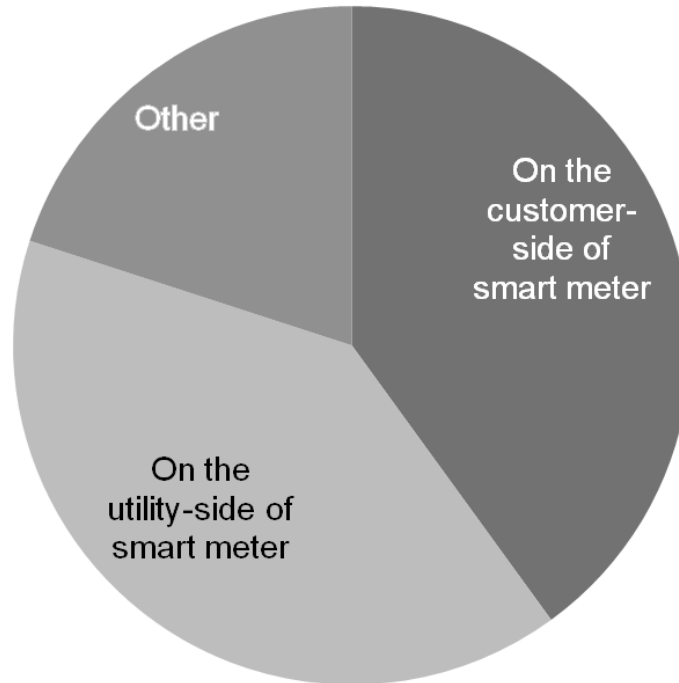
Figure 2.27. Percentages of responses regarding DS location. Three of the "Other" responses were a variation on "*Both*", while the fourth response was "*Utility scale at substations, small scale - utility side until we learn more then could move to customer side*". (*N*=20)

"Useful" Amount of DS
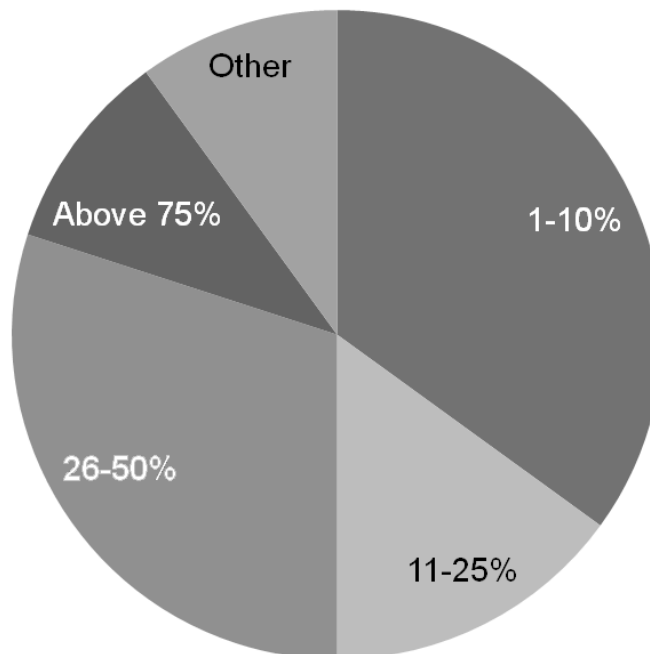
Figure 2.28. Percentages of responses considering the useful amount of DS in percentage of rated load for at least four hours. (*N*=20)

Percentage of Non-Dispatchable DER Supported by DS
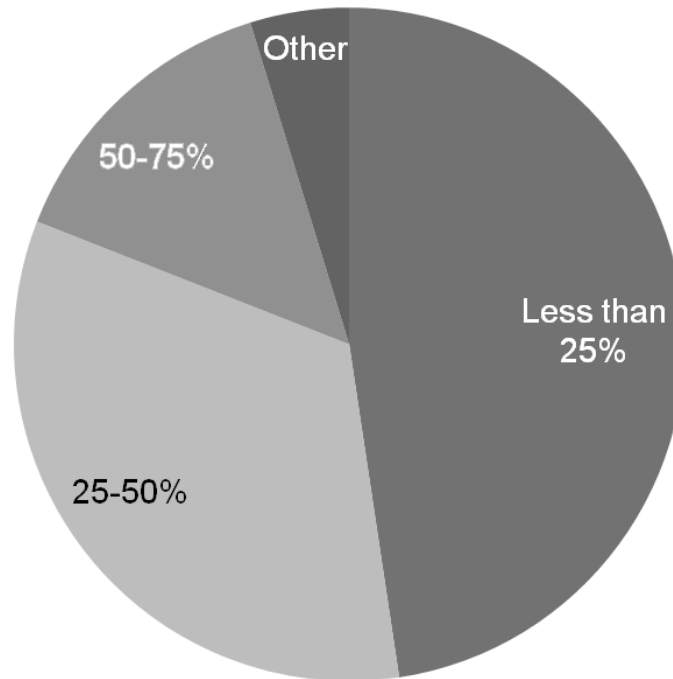
Figure 2.29. The percentages of non-dispatchable DER that are expected to be supported by DS. The "Other" response was "*Not sure at this time*". (*N*=21)

Table 2.10
Relative rankings of DS technologies. A rank of '1' is the most important, while a rank of '8' is the least important.

DS technology	Rank	
	AV	*SD*
Battery storage	1.44	0.70
Flow batteries	2.94	1.30
Flywheels	4.11	0.83
PHEVs	4.17	2.48
UPS	4.28	1.64
Super-capacitors/ ultra-capacitors	5.39	1.29
Compressed air energy storage (CAES)	5.67	1.75
N = 18		
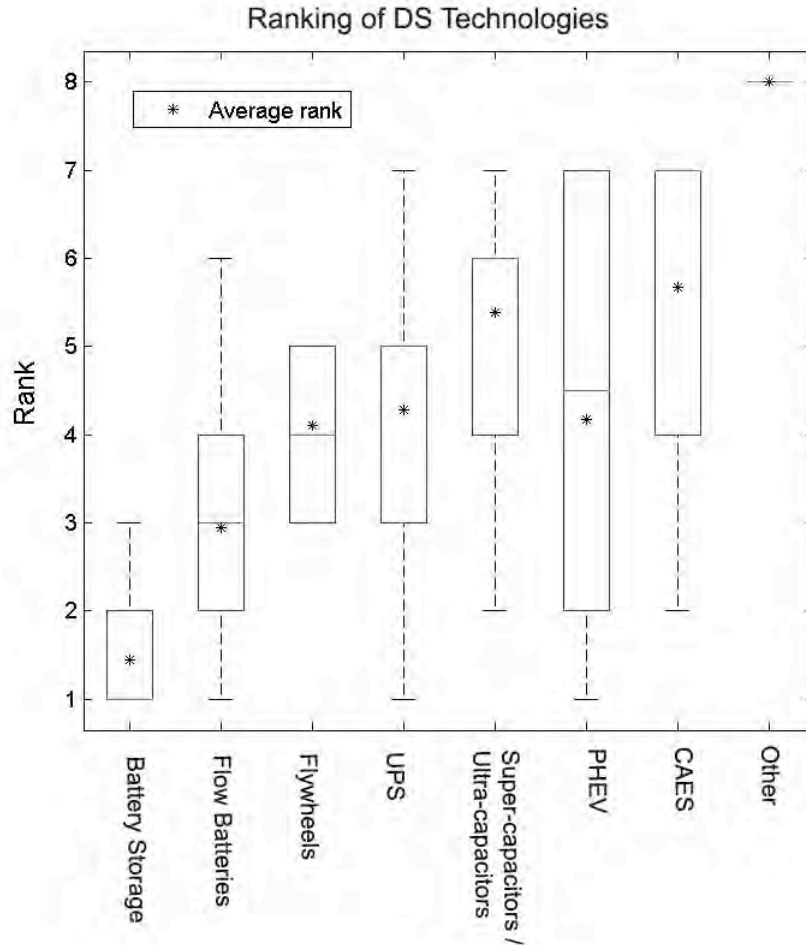
Figure 2.30. A box plot of the rankings of different DS technologies relative to one another. Although PHEV had a large spread of rankings, its average rank was less than the average rank of flywheel storage technologies. Both PHEV and flywheels could be used for frequency smoothing at small time scales. A rank of '1' is the most important, while a rank of '8' is the least important (*N*=18)

Peak-shaving was grouped as a potential application of DER integration, while demand response in the survey was focused on changing demand to reduce consumption. However, it is acknowledged that peak-shaving may also be an application of demand response. As seen in Fig. 2.41, participants did not reach a consensus on the voltage level most suitable for performing peak-shaving: 35% said all distribution voltage levels, and 24% said 120 V. Respondents also did not agree on the method of deciding when peak-shaving should occur – based on dynamic pricing or based on time-of-use (see Fig. 2.42). Types of peak-shaving considered the most important, excepting DER, were residential load control and widespread use of smart appliances, as shown in Fig. 2.43 and Table 2.13. When asked about the time period of activation from the onset of the need for peak-shaving technologies, "within 5 minutes" was the most popular, followed by "within 1 minute" (see Fig. 2.44).

Smart Functionality to Enable DS
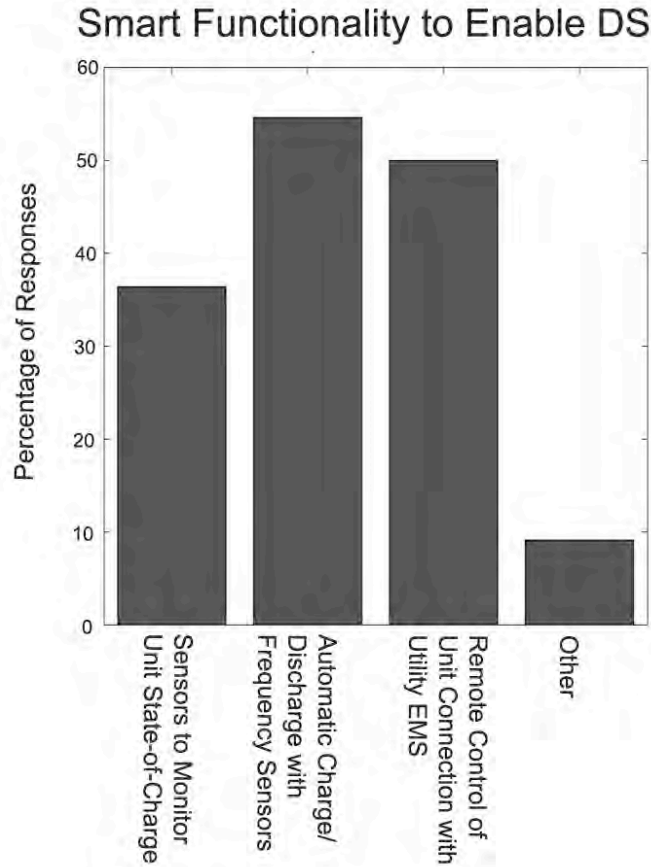
Figure 2.31. Responses about which smart functionalities would enable the inclusion of DS. The "Other" responses were "*Lower-cost, more efficient battery technology*" and "*Real time pricing*". (*N*=22)

2.3.3   Sensing results

Participants said that massively deployed sensors, excluding smart meters, should be located in the 15 kV class (see Fig. 2.45). The information that participants desired from massively deployed sensors is 1) monitor the direction and amount of power flow, 2) monitor locations and usage patterns of DER, and 3) notification of when and how much DER are energizing the system (see Fig. 2.46). Respondents defined "real-time" as once per minute with respect to sensors and smart-metering, as shown in Fig. 2.47. The desired type of sensing technology is "digital sensors with incorporated intelligence" (see Table 2.14 and Fig. 2.48). As seen in Fig. 2.49 and Table 2.15, participants saw alarm-processing algorithms as the most important application for massively deployed sensors. Fig. 2.50 shows the smart functionality expected to be possessed by massively deployed sensors.

Overwhelmingly, respondents said that the smart meter should act as both a communications link and local control system (see Fig. 2.51). The desired functionality of the smart meter is shown in Table 2.16, with the bar graph shown in Fig. 2.52. It is pertinent to note that in Table 2.6, current and voltage profiling, as well as to store and download time-of-use schedules both had more that 70% of the response.
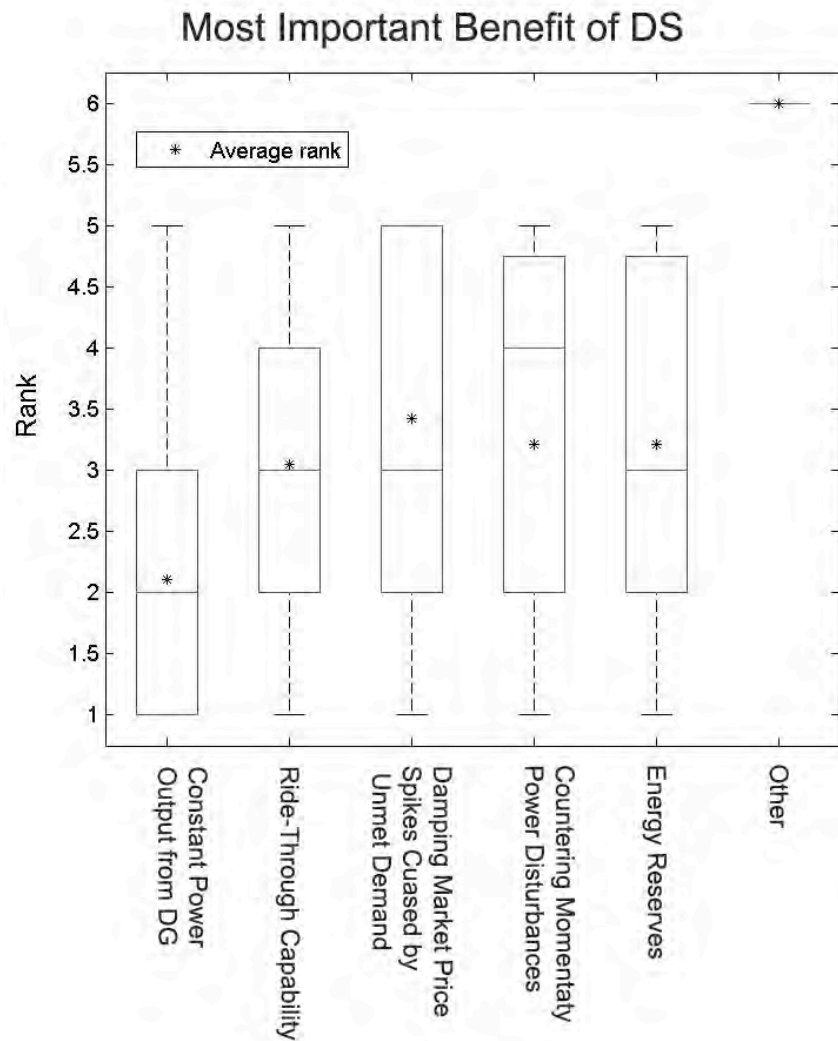
Figure 2.32. A box plot of the rankings of the perceived benefits of DS. Although the most important benefit is clearly "Constant power output from DG", responses were equally divided among the other benefits. A rank of '1' is the most important, while a rank of '6' is the least important. (*N*=19)

Table 2.11
Relative rankings of the perceived benefits of DS. A rank of '1' is the most important, while a rank of '6' is the least important. These results are shown in a box plot in Fig. 2.32.

Benefit	Rank	
	AV	SD
Constant power output from distributed generation	2.11	1.24
Ride-through capability during faults and outages	3.05	1.35
Damping price spikes in market caused by unmet electricity demand	3.42	1.35
Countering momentary power disturbances	3.21	1.55
Energy reserves	3.21	1.36
Other	6.00	0.00
N = 19		

2.3.4 Demand response results

Participants identified "dynamic pricing" as the most important smart function to enable consumer participation in demand response (see Fig. 2.53 and Table 2.17). Within dynamic pricing, "real-time" pricing was the preferred pricing type, as shown in Fig. 2.54. With respect to the PCC, utilities can give consumers no control, very limited control, limited control, or total control of utility-approved installations, readers are referred to Section 2.1.2 for the definitions of these control options. Given these options, 35.7% were inclined to give the consumer "limited" control and another 35.7% gave "total" control (see Fig. 2.55). When asked if the utility should have override capability, 40% answered "No" and 33.3% answered "Yes, for all cases" (see Fig. 2.56).

Three technologies were identified as enabling demand response, as seen in Fig. 2.57: 1) programmable, communicating consumer devices, or smart appliances, 2) advanced metering infrastructure, and 3) building/facility energy management system interfaced with market pricing signals. The "useful time frame" for automated demand response is shown in Fig. 2.58, and was "within minutes" by a majority of the survey participants.

2.3.5 Self-healing results

Most respondents thought that adaptive and self-healing technologies would be incorporated into the distribution system at the 15 kV class and 35 kV class, as shown in Fig. 2.59. There was no consensus on the desired philosophy of self-healing: preventative, corrective, emergency, or restorative (see Fig. 2.60 and Table 2.18); note that the choices for the desired philosophy of self-healing were adapted from [89]. As shown in Fig. 2.61, most participants thought that self-healing would be accomplished through a

combination of automated processes and utility-supervised actions. When asked how effective self-healing at the distribution level should be with respect to a variation of the ASAI, defined in [78], most participants cited a goal of 0.9999 (4 nines) or 0.99999 (5 nines), as seen in Fig. 2.62.
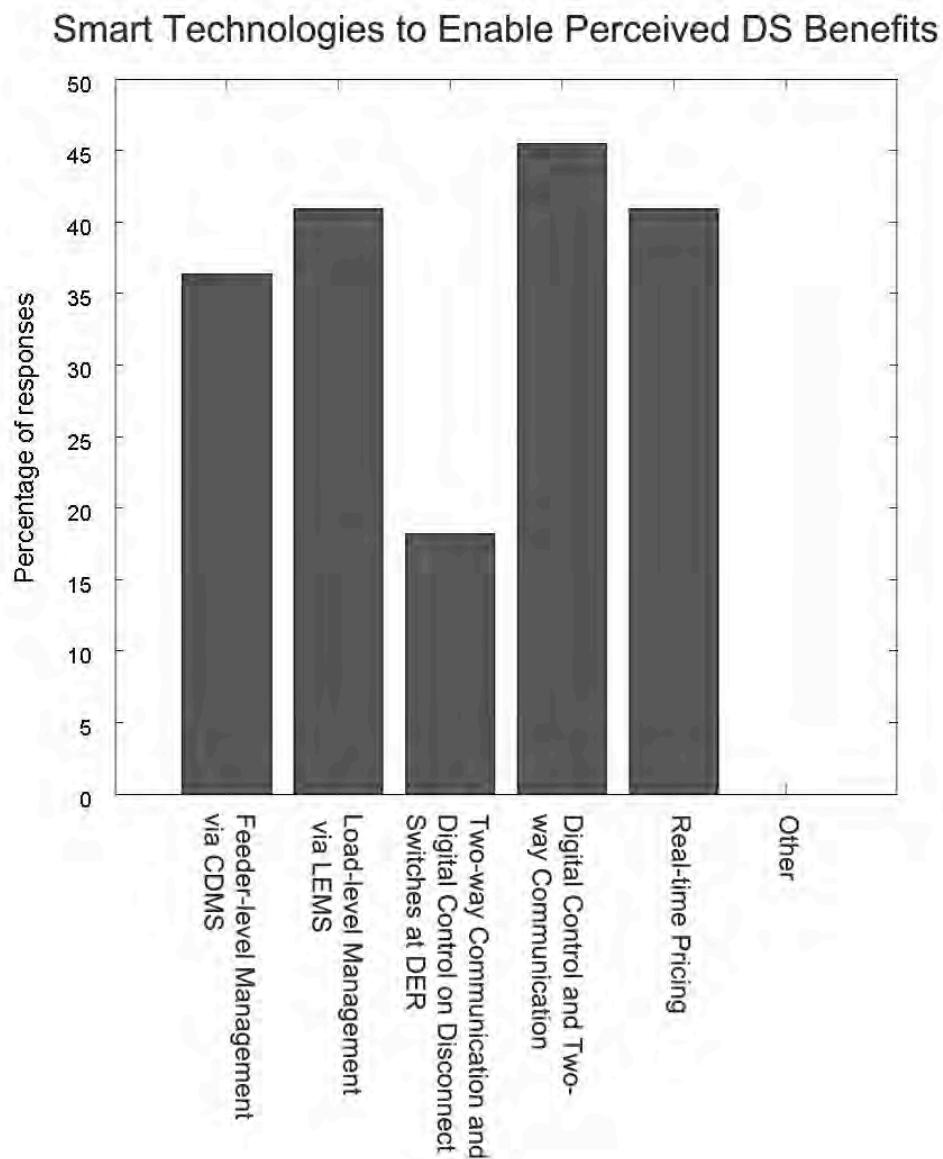
Figure 2.33. Percentages of responses considering which technologies could best enable the perceived benefits of DS. No one response received more than 46% of the total responses on this multi-select question. (*N*=22)
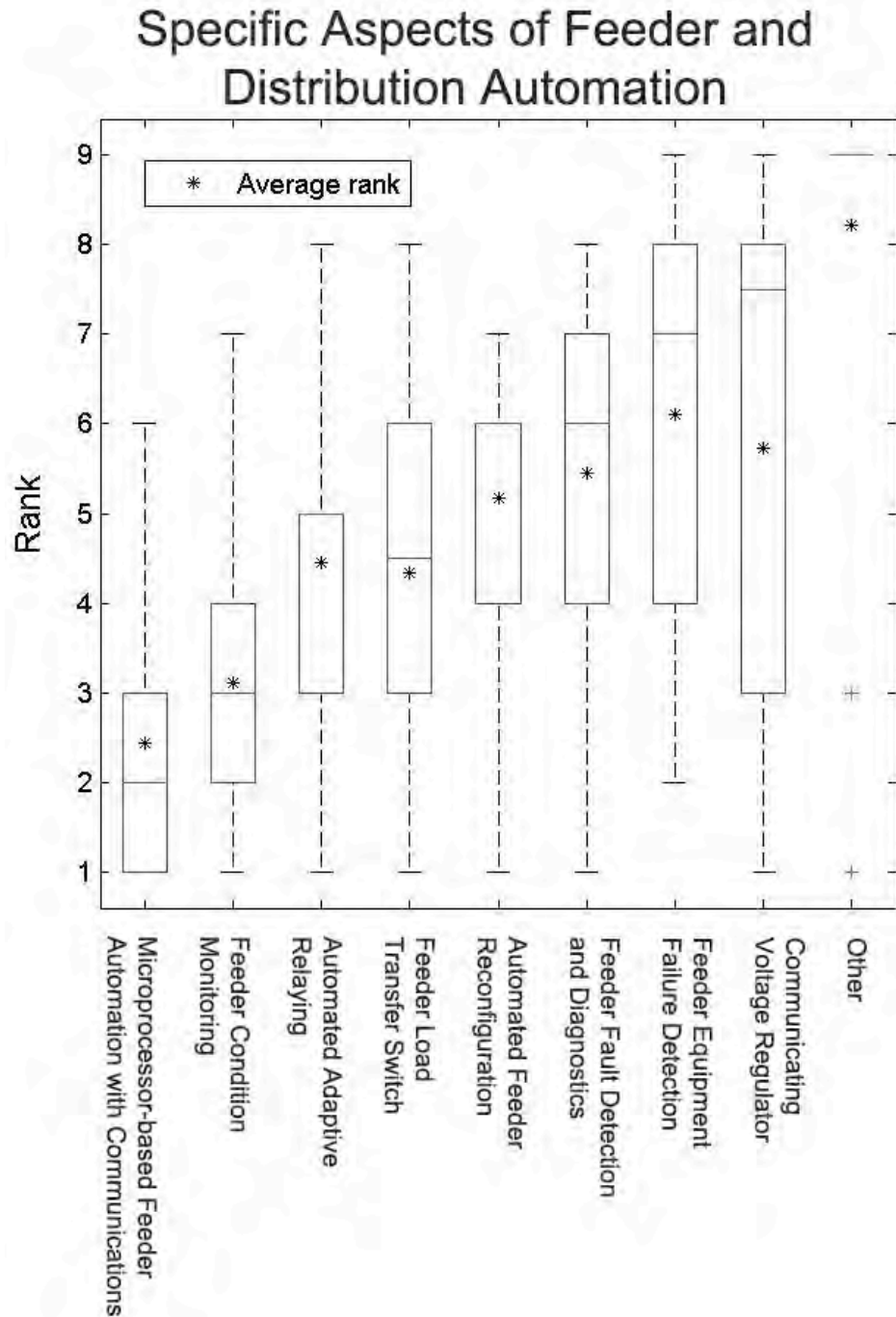
Figure 2.34. Box plot considering specific aspects of feeder and distribution automation (if it is assumed to be a smart technology) that are the most important to the integration of DER. A rank of '1' is the most important, while a rank of '9' is the least important. (*N*=18)

Table 2.12
Relative rankings of the specific aspects of feeder and distribution automation that are the most important to the integration of DER. A rank of '1' is the most important, while a rank of '9' is the least important. These results are shown in a box plot in Fig. 2.34.

Aspect of feeder and distribution automation	Rank	
	AV	*SD*
Microprocessor-based feeder automation with communication capability	2.44	1.42
Feeder condition monitoring to improve reliability	3.11	1.68
Automated adaptive relaying	4.44	2.06
Feeder load transfer switch for demand response (load management)	4.33	2.09
Automated feeder reconfiguration for loss reduction or overload relief	5.17	1.50
Feeder fault detection and diagnostics	5.44	2.15
Feeder equipment failure detection	6.11	2.11
Voltage regulator with communication capability	5.72	2.99
Other	8.22	2.29
N = 18		

The activation timeframe for self-healing actions was the "several cycles range" and the restoration timeframe, once action had been activated, was "within minutes" (see Figs. 2.63 and 2.64, respectively). The desired activation timeframe is shown in Fig. 2.65, with a circle marking the desired timeframe. Participants thought that smart feeders and smart substations should hold the responsibility for self-healing functions (see Fig. 2.66 and Table 2.19). Although operations centers were not expected to hold the responsibility for self-healing, respondents selected integrated outage management and AMI as two ways to add smart functionality to operations centers, as seen in Fig. 2.67 and Table 2.20. Table 2.21 and Fig. 2.68 show that respondents expected "smart feeder automation" to add "smarts" to feeder and distribution automation. Many of the options given for adding "smarts" were developed from [15].

2.3.6   Advanced tools results

Advanced tools include tools for visualization, analysis, and simulation, and are intended to streamline routine operations. To define the functionality of a smart distribution system management program, respondents were asked to select from the following:

    i.   Automatic reporting to utility of smart meter measurements with time stamp, and the use of data to plan and/or predict future usage

ii.   Price predictions of energy to plan future usage

iii.   Optimize portfolio of loads, DG, and DS for use in load flow studies

iv.   Create back-up arrangements if specific components were to fail or be inactive (i.e., if solar panels were unusable due to weather; if islanded from grid; if storage unit fails)

v.   Customer-driven – i.e. customer "designs" personal system and receives utility approval for grid connection

vi.   Utility-driven – i.e. utility decides the amount and mix of DER that a customer is allowed.

Option 1 from the above list was selected by approximately 65% of respondents. Options 2 – 5 were selected by approximately 47% of respondents. The results are shown in Fig. 2.69.
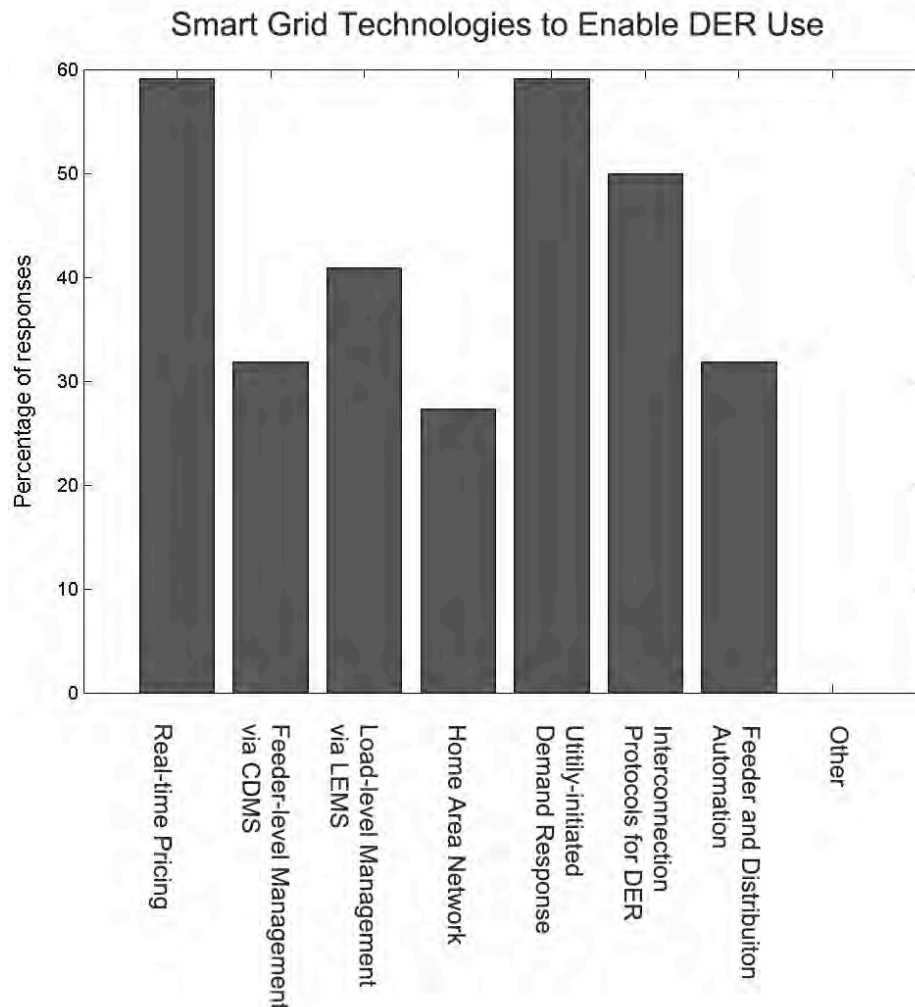
Figure 2.35. Percentages of smart grid technologies that are expected to enable the use of DER. The two top responses were "*Real-time pricing*" and "*Utility-initiated demand response*". (*N=22*)
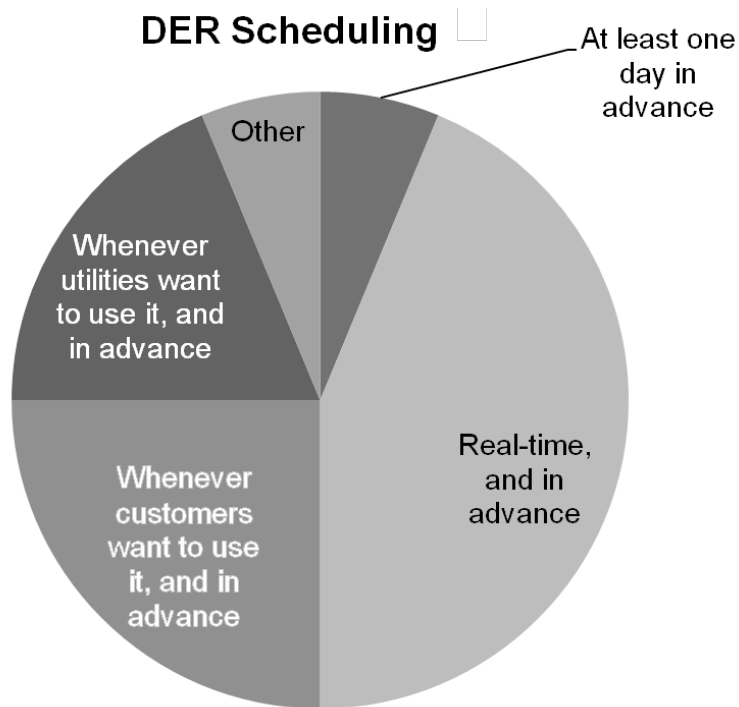
Figure 2.36. Responses considering how DER usage should be allowed. The "Other" response was "*Most should be allowed, but the consumer should be allowed to respond to a price signal for generation and load*". (N=16)
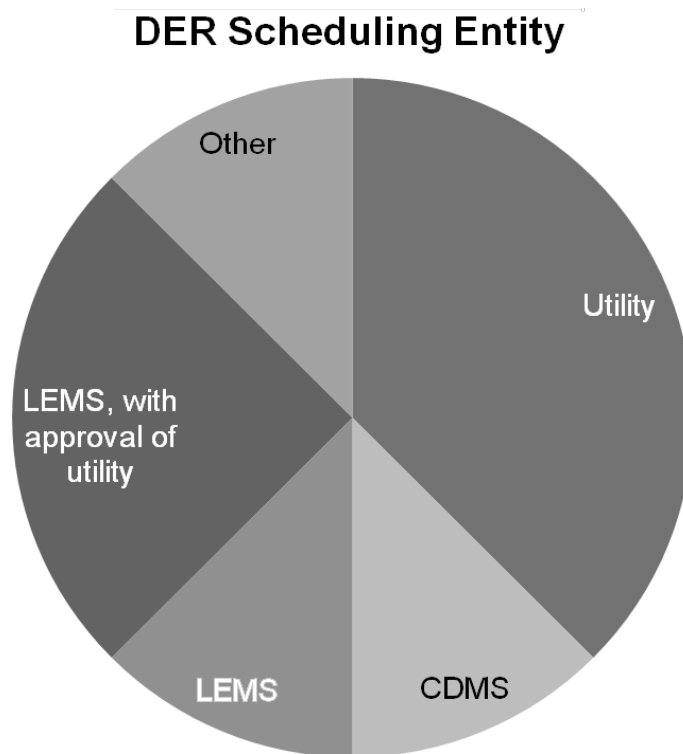
Figure 2.37. Percentages of responses to determine who should schedule DER. The "Other" responses were "*Utility or ISO based on price-based auctions*" and "*The consumer should be allowed to respond to price signals, plus all of the above*". (N=16)

DER Scheduling Limits
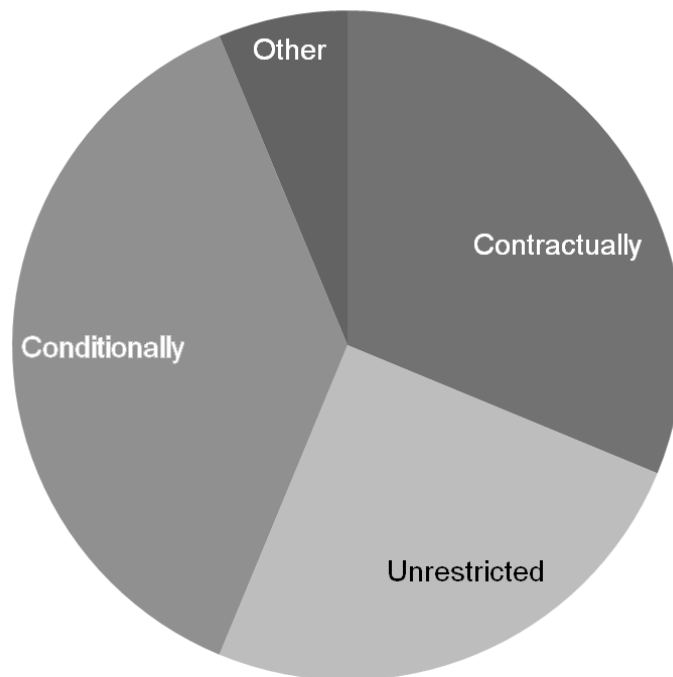
Figure 2.38. Responses considering the limiting mechanisms on DER scheduling and participation. The "Other" response was that "*The utility should provide a price for DER scheduling*". (*N*=16)

Communications Between DER and Utility EMS
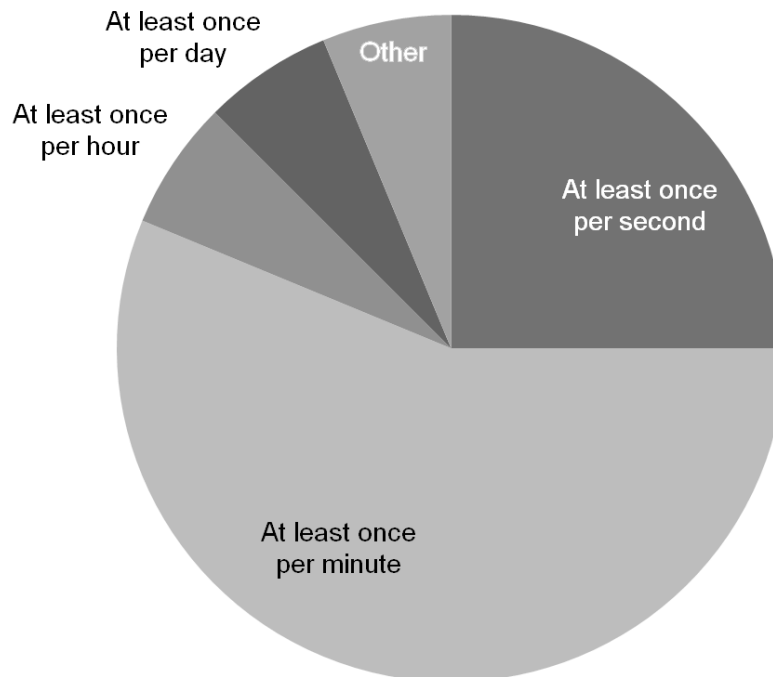
Figure 2.39. Frequency of communication between DER and the utility EMS. The "Other" response was "*The communication can be once a day but the detail should be fine enough to capture once a second activities* [sic]". (*N*=16)
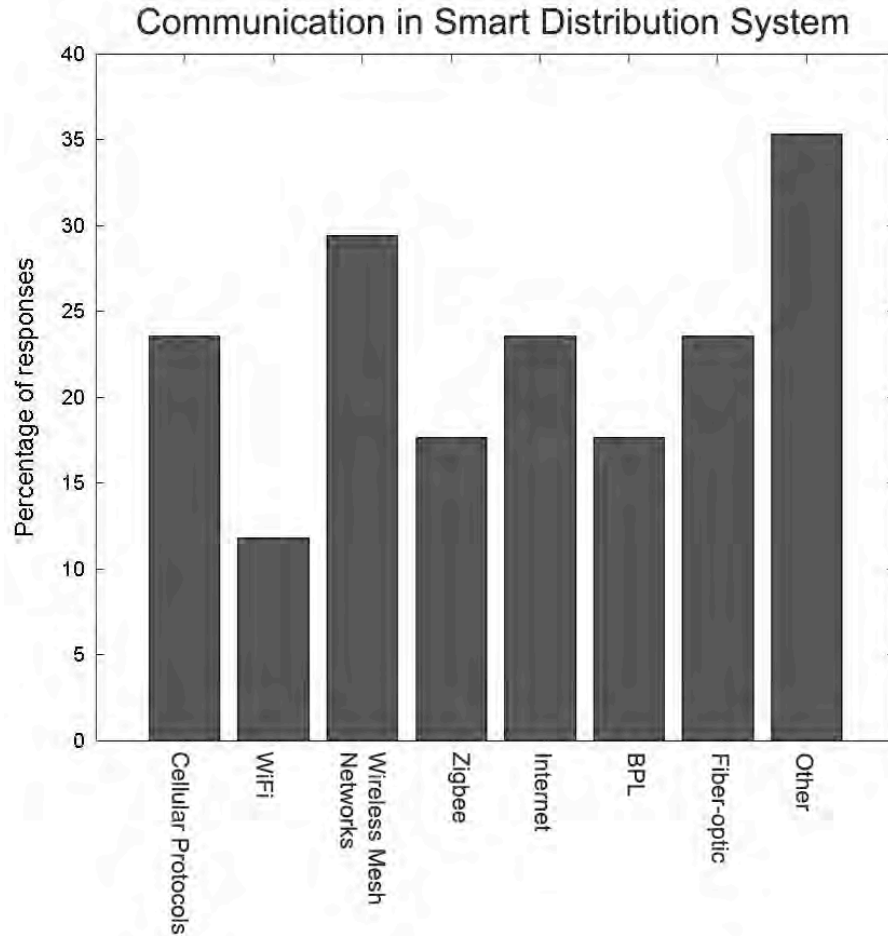
Figure 2.40. Communications technologies in the smart distribution system. No single response received more than 30% of the responses, excluding the "Other" option. Three of the "Other" responses were a variation on "*All of the above*", and the remaining responses were "*Communication will depend upon the application*", and "*Its going to take a secure, multi-media system, not 1* [sic]". (*N*=17)

With respect to data storage, 33% of the responses wanted all data – "critical", "useful", and "other" – while 47% thought that "critical" and "useful" data was sufficient (see Fig. 2.70). As shown in Fig. 2.71, data storage centers are expected to be located at data-collection centers distributed throughout the system (i.e., a substation) or at the utility center of operations.

2.3.7   *Consumer device results*

Respondents were asked to identify the most useful types of smart appliances – thermal devices, programmable devices, or smart circuit devices – of which over 50% chose smart circuit devices, as seen in Fig. 2.72. Seventy percent believed that smart appliances should be equipped with two-way communication and just over 50% believed smart appliances should also have control algorithms (see Fig. 2.73). As shown in Fig. 2.74, there was no consensus over where the control system for the smart

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appliances should be located: on the device, LEMS, smart meter, or a demand response/load management program.

Voltage Level of Peak-shaving
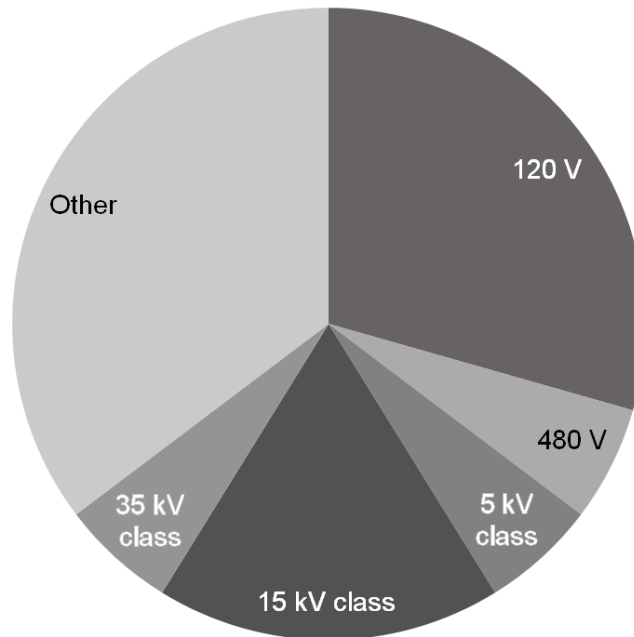
Figure 2.41. Percentages of responses to the desired voltage level of peak-shaving. All "Other" responses were a variation on "*All of the above*". (*N*=17)

Peak-shaving Should Occur...
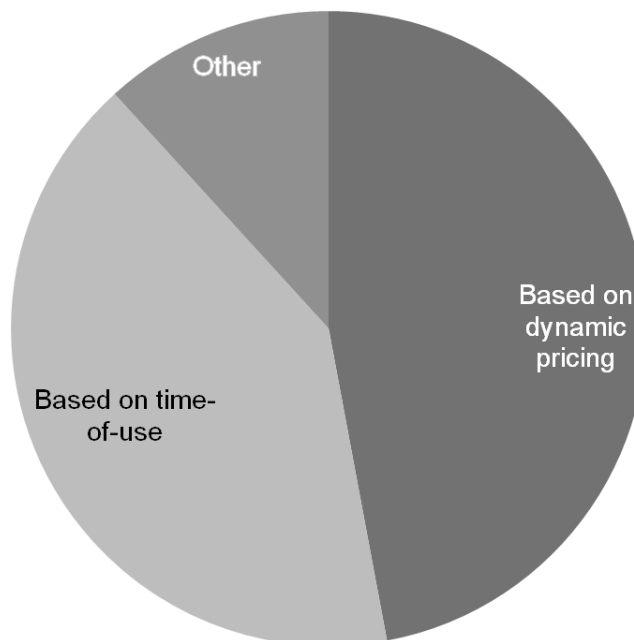
Figure 2.42. Responses considering how peak-shaving should be used. The "Other" responses were "*When peak occurs*" and "*Both, but especially dynamic pricing*". (*N*=17)
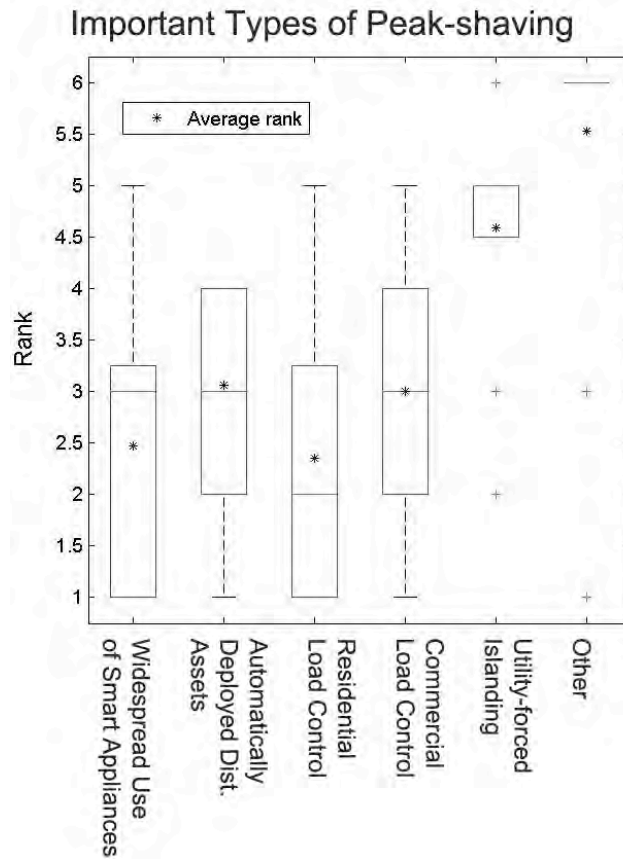
Figure 2.43. A box plot of the ranking of the types of peak-shaving expected to be the most important, in addition to DER. A rank of '1' is the most important, while a rank of '6' is the least important. (*N*=17)

Table 2.13
Relative rankings of the types of peak-shaving expected to be the most important, in addition to DER. A rank of '1' is the most important, while a rank of '6' is the least important. These results are shown in a box plot in Fig. 2.43.

Peak-shaving type	Rank	
	AV	*SD*
Widespread use of "smart" appliances	2.47	1.33
Automatically deployed distributed assets	3.06	1.09
Residential load control, i.e. utility controls when large residential loads are run (for example, air-conditioning units or furnaces)	2.35	1.41
Commercial load control, i.e. utility controls when certain commercial loads are run	3.00	1.37
Utility-forced islanding of specific, pre-defined load areas	4.59	1.12
Other	5.53	1.37
N = 17		

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When Should Peak-shaving Engage?
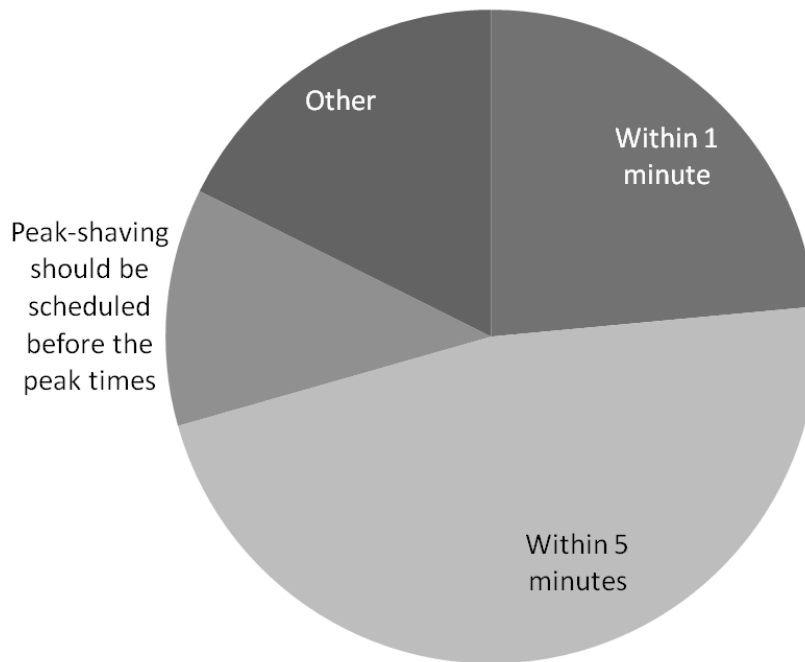
Figure 2.44. Percentages of responses considering when peak-shaving should engage. The "Other" responses were "*15 minutes*", "*Scheduled peak shaving w/ emergency fast shaving* [sic]", and "*Each should be accomodated with differing prices for the speed* [sic]". (*N*=17)

Voltage Level of Massively Deployed Sensors
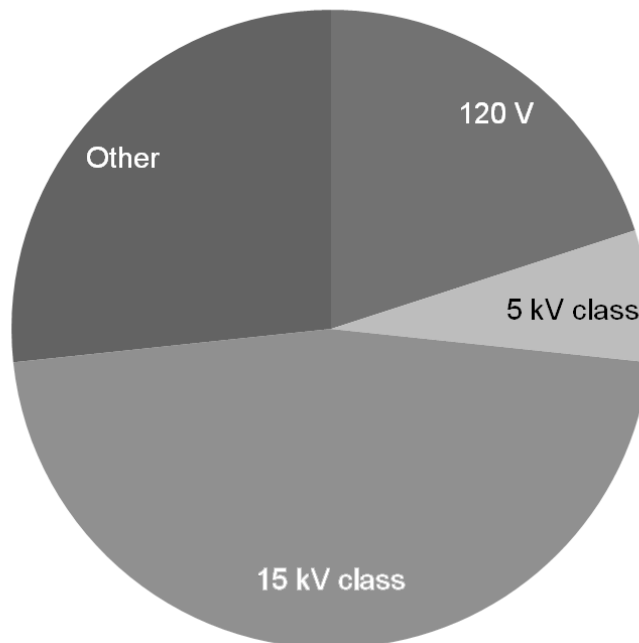
Figure 2.45. Responses considering the best voltage for massively deployed sensors. Three of the "Other" responses were "*All of the above*" and the remaining response was "*Based upon the distribution voltage*". (*N*=15)
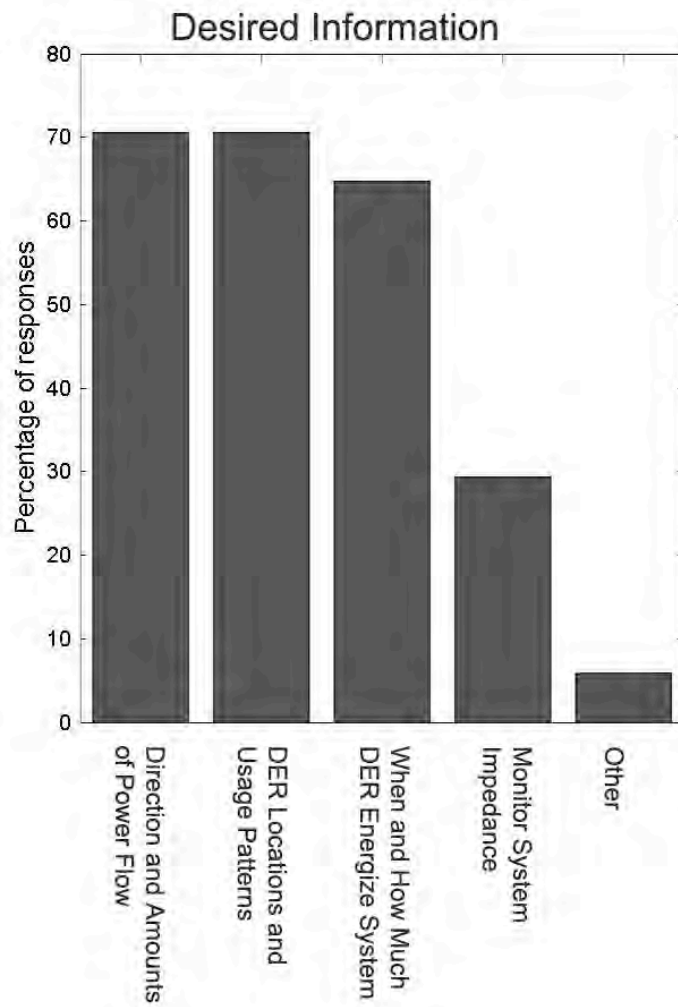
Figure 2.46. Responses regarding the desired information from massively deployed sensors. The system impedance would be monitored in order to ensure accurate protection systems. The "Other" response was "*All of the above*". (*N*=17)

2.3.8 *Islanding results*

There was no consensus on the voltage level for islanding ability, although the most popular responses were the 5 kV class, 15 kV class, and "Other" (see Fig. 2.75). Over 50% of respondents said that a system with islanding potential should have control systems for local voltage regulation, real power balance, and reactive power balance, as shown in Fig. 2.76. The same percentage believed that the utility should have the ability to identify islands, i.e., a communication link between the island and the utility. There was also no consensus about the way a system with islanding potential should switch to an island (see Fig. 2.77). To enable the switching from islanded to grid-connected modes, respondents said that an enabling smart technology would be to implement controls for grid-like behavior, as seen in Fig. 2.78.

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Real-time For Massively Deployed Sensors and Smart Meters
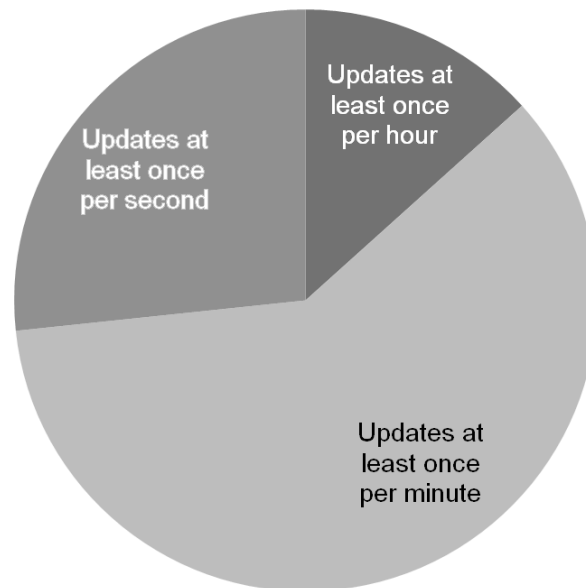
Figure 2.47. The definition of real-time for massively deployed sensors and smart meters. (*N*=15)

Table 2.14
Relative rankings of sensor types that should have an increased presence in the distribution system. A rank of '1' is the most important, while a rank of '13' is the least important.

Sensor	Rank	
	AV	*SD*
GMR	4.23	1.92
Optical	4.62	1.71
Hall effect	5.23	2.28
Satellite	6.00	2.20
Mechanical	5.92	2.29
Chemical	9.15	2.08
Video	8.08	1.80
PMU	5.46	3.84
Digital sensors with incorporated intelligence	3.38	3.69
Thermal	6.00	3.51
Shock	11.15	0.55
Photo	10.61	3.25
Other ✓ *Who knows, this will take some experimentation* ✓ *I am not qualified to answer this question*	11.15	4.51
N = 13		
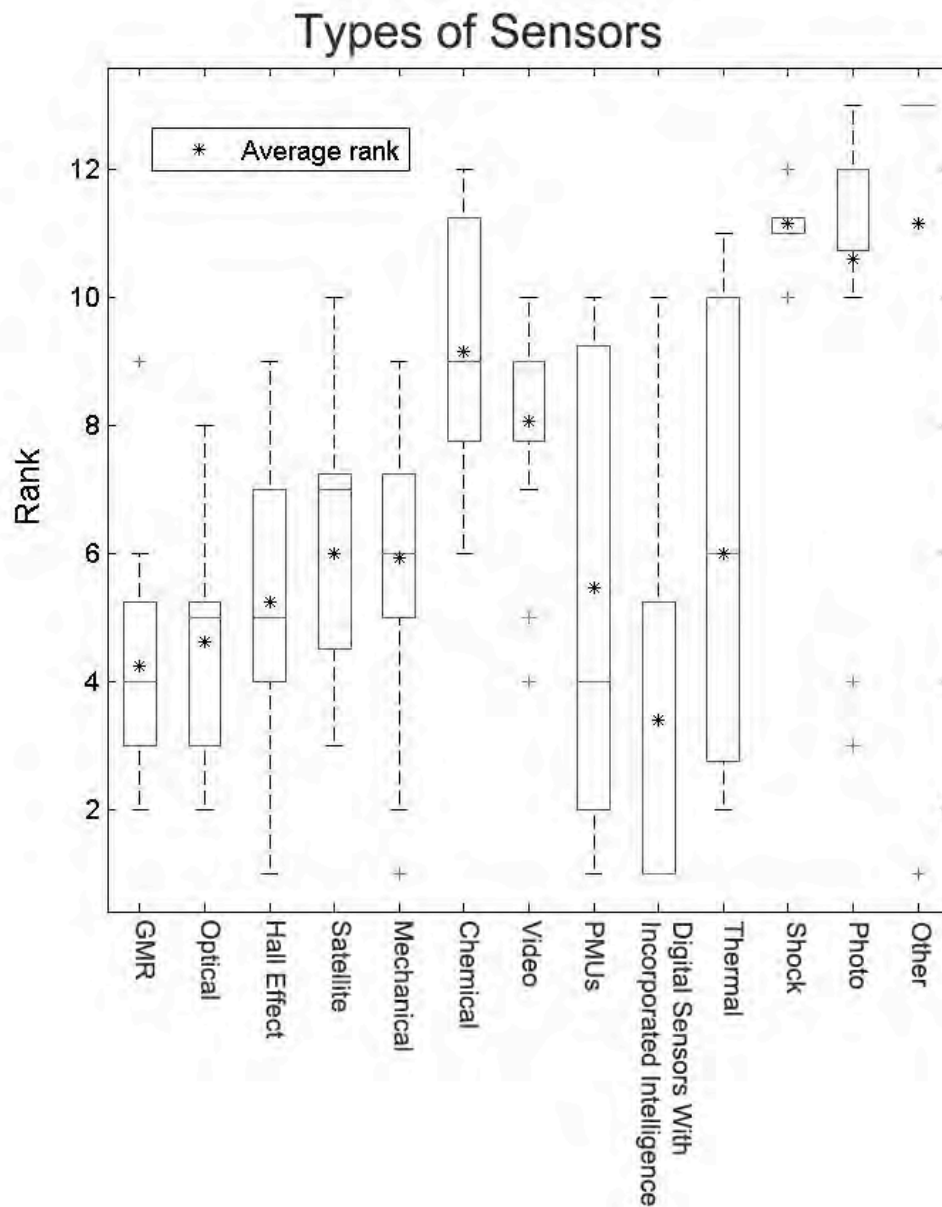
Figure 2.48. Box plot of the ranks of different types of sensors relative to one another. Many of the sensor choices are already implemented at the transmission level, but have a limited presence at the distribution level. A rank of '1' is the most important, while a rank of '13' is the least important. These results are shown in Table 2.14. (*N*=13)
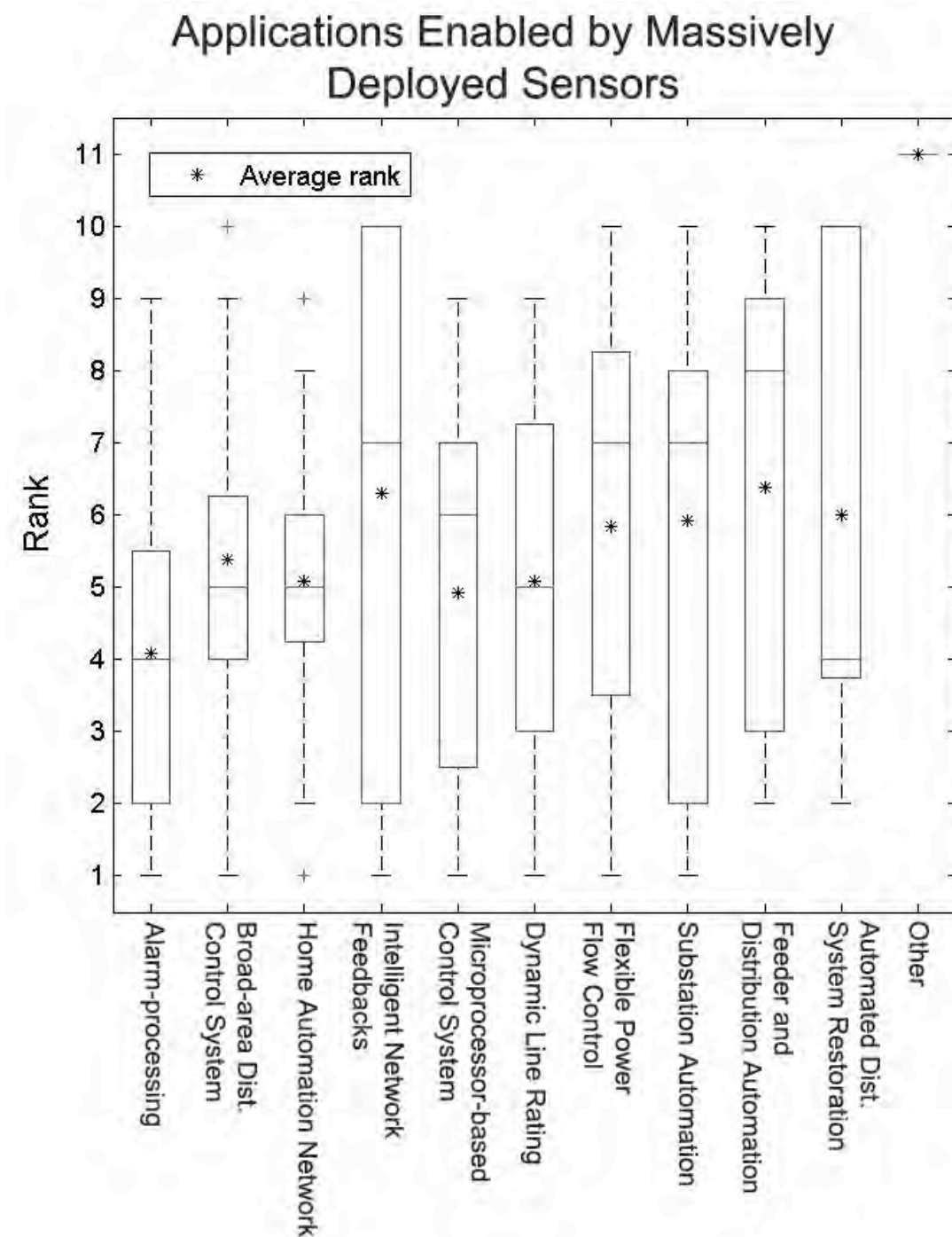
Figure 2.49. A box plot of the ranking of the possible applications enabled by massively deployed sensors. Most responses had a wide spread. A rank of '1' is the most important, while a rank of '11' is the least important. (N=13)

Table 2.15

Relative rankings of the possible applications enabled by massively deployed sensors. A rank of '1' is the most important, while a rank of '11' is the least important. These results are shown in a box plot in Fig. 2.49.

Application	Rank	
	AV	*SD*
Alarm-processing algorithms, triggered based on system data gleaned from massively deployed sensors, to take action in non-critical situations	5.07	2.56
Apply ideas from wide-area measurement systems (WAMS) and wide-area control systems (WACS) to create a broad-area distribution control system, which could control distribution system components to optimize certain values, such as reactive power	5.38	2.40
Home automation network interfaced with utility smart grid system	5.08	2.29
Applying intelligent network feedbacks to create a new market system	6.31	3.73
Upgrade and replace existing electro-mechanical control system with microprocessor-based control system, enabling communication	4.92	2.69
Dynamic line rating to improve system reliability	5.08	2.69
Flexible power flow control	5.85	3.11
Substation automation	5.92	3.09
Feeder and distribution automation	6.38	3.04
Automated distribution system restoration	6.00	3.14
Other	11.00	0.00
N = 13		
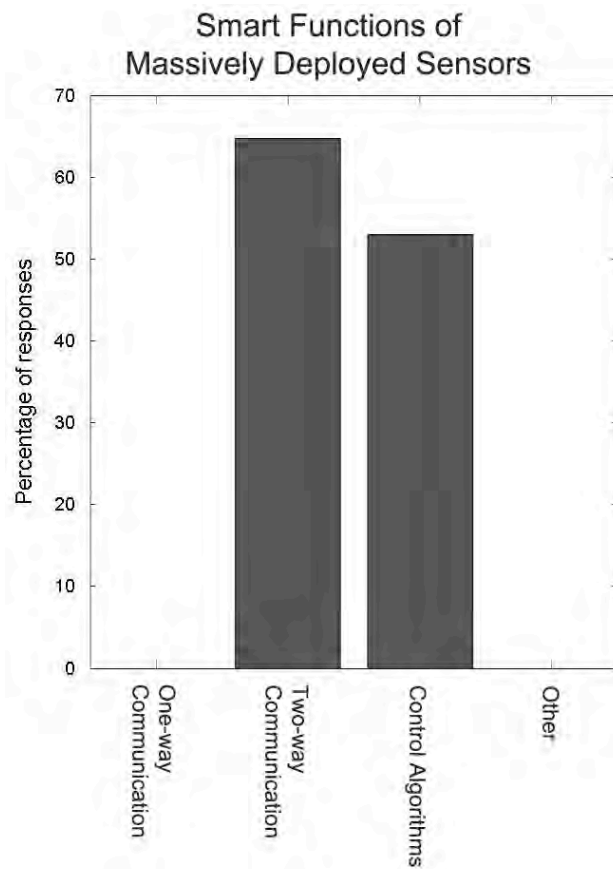
Figure 2.50. Responses of the desired smart functionality of massively deployed sensors. (*N*=17)
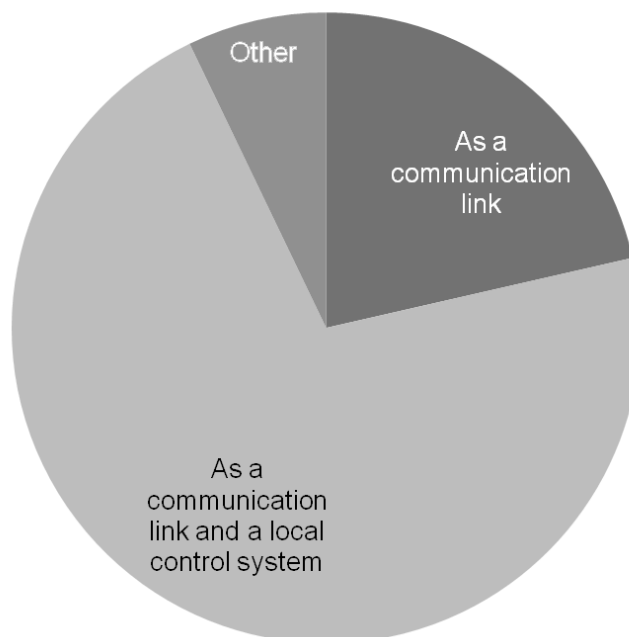
Figure 2.51. Responses concerned with how a smart meter should act. The "Other" response was "*A mixture of both, depending on size of customer*" (*N*=14)

Table 2.16

Smart meter functionality, percentages of responses. The bar graph of the following results is shown in Fig. 2.52.

Function	*Percentage of responses*

Communication
  ✓ Two-way communication with utility
  ✓ Two-way communication with other devices, such as DER or LEMS or CDMS
	
	58.8
	58.8

Reads
  ✓ Real-time
  ✓ On demand
  ✓ Scheduled
	
	58.8
	47.1
	47.1

Automation
  ✓ Automatic registration
  ✓ Time synchronization
	
	35.3
	58.8

Alarms
  ✓ Tamper detection
  ✓ Power quality monitoring and alarms
  ✓ Outage and restoration alarms
	
	64.7
	52.9
	52.9

Profiling
  ✓ Current and voltage
  ✓ Demand, load, and generation
	
	70.6
	47.1

Scheduling
  ✓ Schedule and bid for system activity
  ✓ Store and download time-of-use schedules
	
	29.4
	70.6

Control
  ✓ DER
  ✓ Interpret system economic activity
	
	35.3
	29.4

Miscellaneous
  ✓ Event logging
  ✓ Ability to measure bi-directional power flow
	
	52.9
	47.1

Other	0
N = 17	
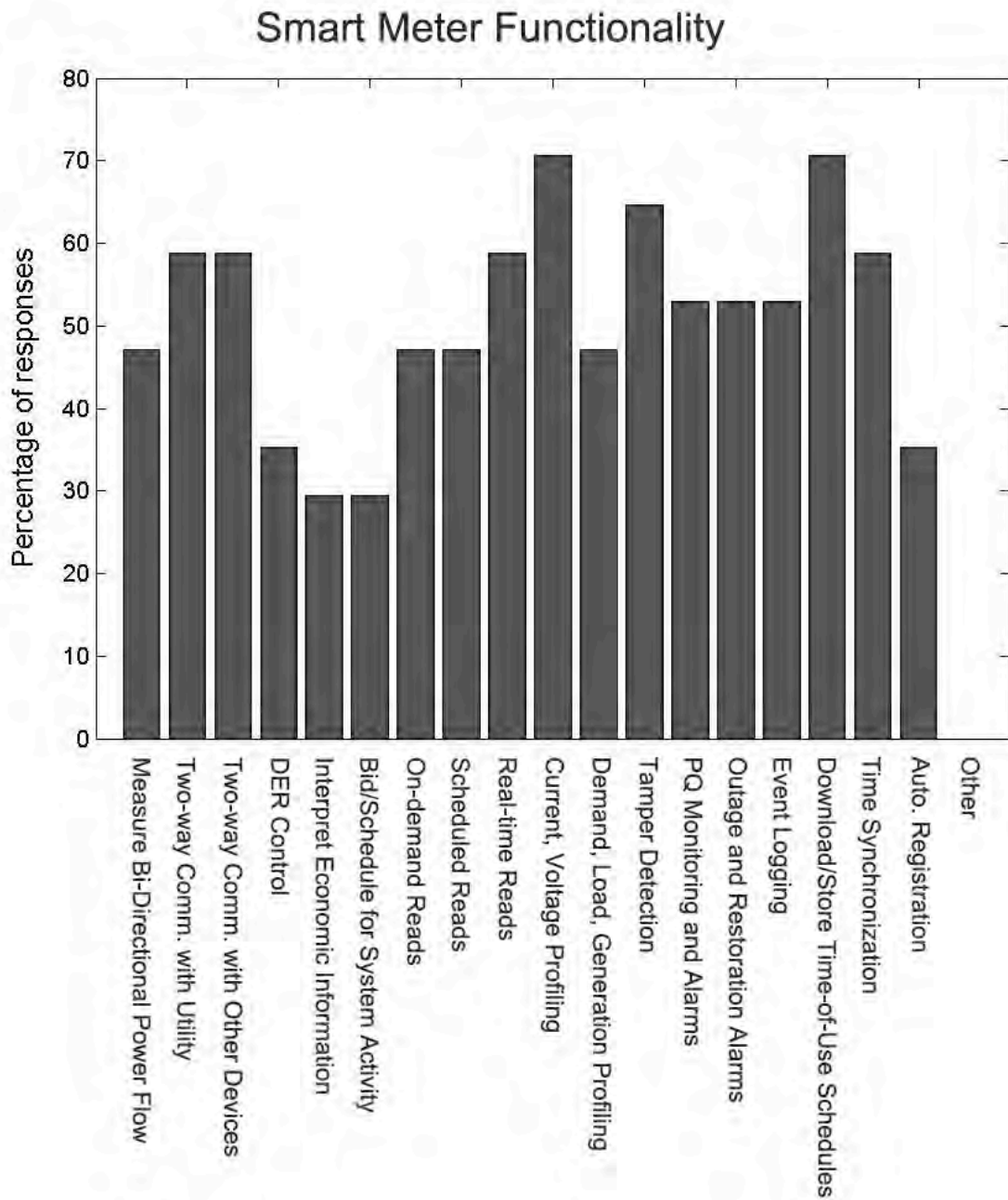
Figure 2.52. Percentages of responses dealing with the functionality of a smart meter. The options are organized into general categories in Table 2.6. (N=17)
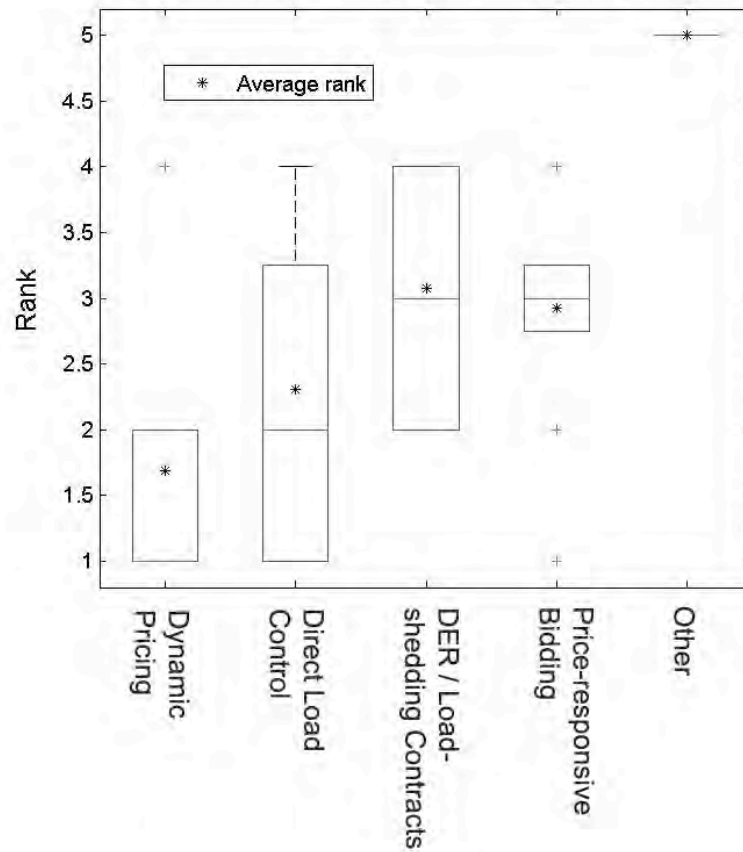
Figure 2.53. Box plot of responses ranking smart functions would enable demand response. A rank of '1' is the most important, while a rank of '5' is the least important. (*N*=13)

Table 2.17
Relative rankings of smart functions would enable demand response. A rank of '1' is the most important and a rank of '5' is the least. These results are shown in a box plot in Fig. 2.53.

Smart function	Rank	
	AV	*SD*
Dynamic pricing	1.69	1.11
Direct load control or load cycling by utilities	2.31	1.18
Contractual obligations to load curtailment and/or DER deployment	3.08	0.86
Price-responsive demand bidding	2.92	0.86
Other	5.00	0.00
N = 13		

Preferred Dynamic Pricing
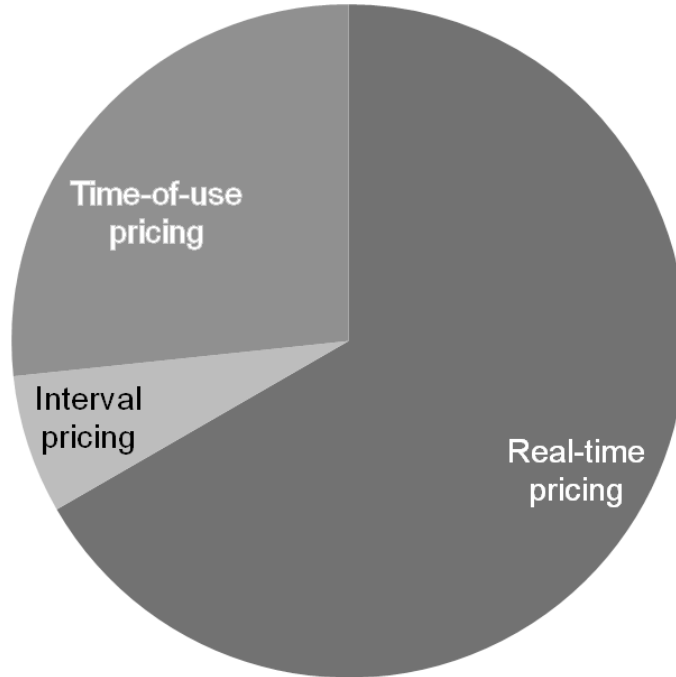
Figure 2.54. Responses considering the preferred method of dynamic pricing. "Critical peak pricing" was also given as an option, although it received no responses. (*N*=15)

Customer Control at PCC
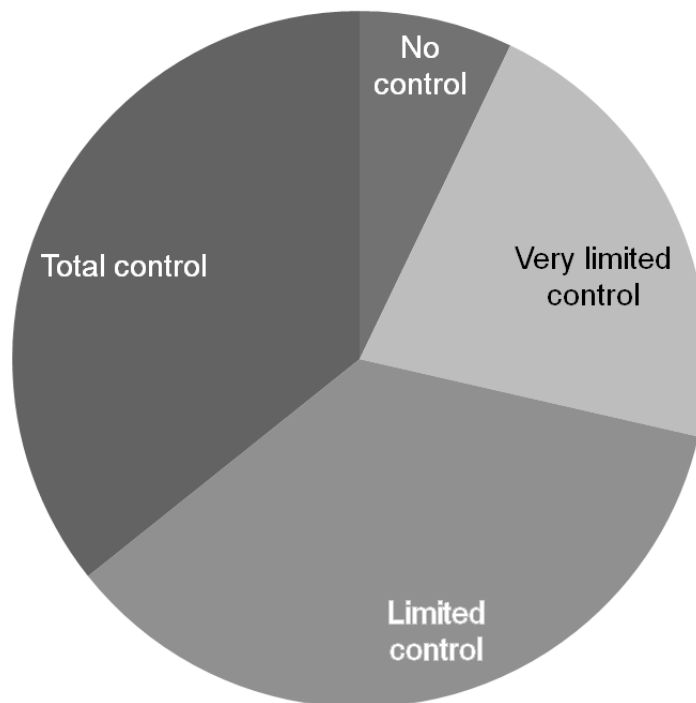
Figure 2.55. Responses considering what level of control consumers should be allowed at the PCC. Most participants leaned toward the consumer having more control, rather than less. (*N*=14)
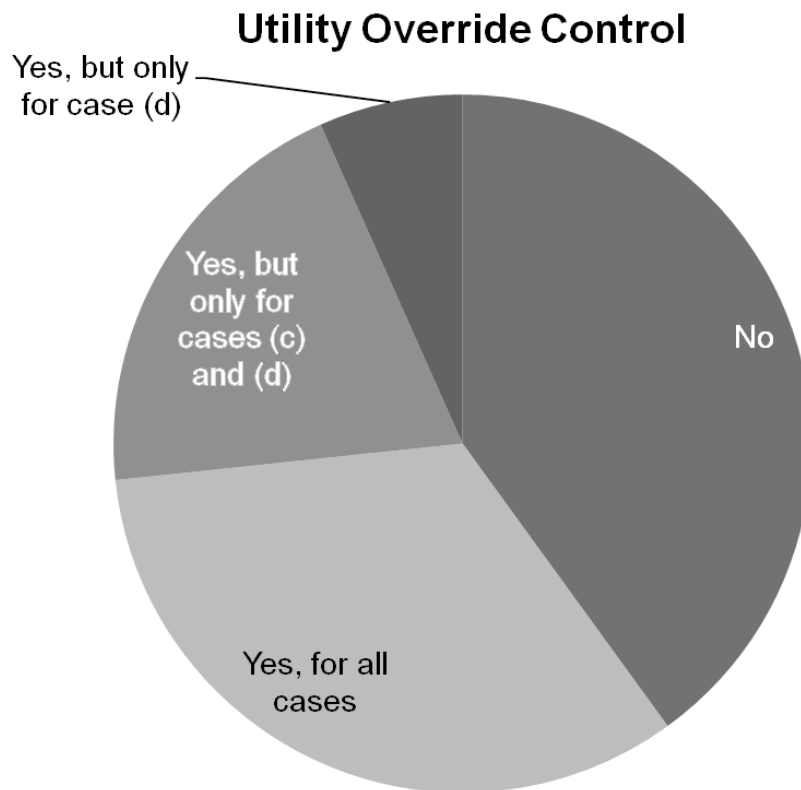
Figure 2.56. Responses to whether or not the utility should have override control on the options shown in Fig. 2.55. "Limited control" and "Total control" in Fig. 2.55 correspond to (c) and (d), respectively, in this figure. (*N*=15)

2.4 Concise summary of results

Based on the results of the survey of respondents from the industry and academia, some characteristics of a smart distribution system have been defined [84]. A **smart distribution system**:

i. **Optimizes distributed assets** through the use of real-time pricing, AMI, two-way communicating devices, and networked connections between feeders. New market and product opportunities are enabled by plug-and-play methodologies, expected supply of ancillary services, and smart-grid tailored devices.

ii. **Incorporates DER** at all distribution voltage levels enabled with two-way communications. DER usage will be scheduled in advance and in real-time by the utility. Local management of DER will incorporate the LEMS at a minimum, but may also incorporate both the LEMS and the CDMS. DER will communicate with the smart meter, LEMS, and one another at least once per minute. Approximately 10-19% of total generation will be met via RE resources, such as photovoltaic, biogas/biomass, CHP, and wind. Less than 50% of new DER are expected to comprise RE resources, which will be

supported by battery storage and fast-starting dispatchable generation sources. DS (primarily batteries) will comprise less than 50% of rated load for up to four hours, and are expected to support up to 50% of non-dispatchable DER. Peak-shaving techniques employed primarily in the 120 V class, such as residential load control, will engage within approximately fifteen minutes.

Figure 2.57. Percentages of responses about smart technologies expected to enable demand response. (N=17)

"Useful" Timeframe for Demand Response
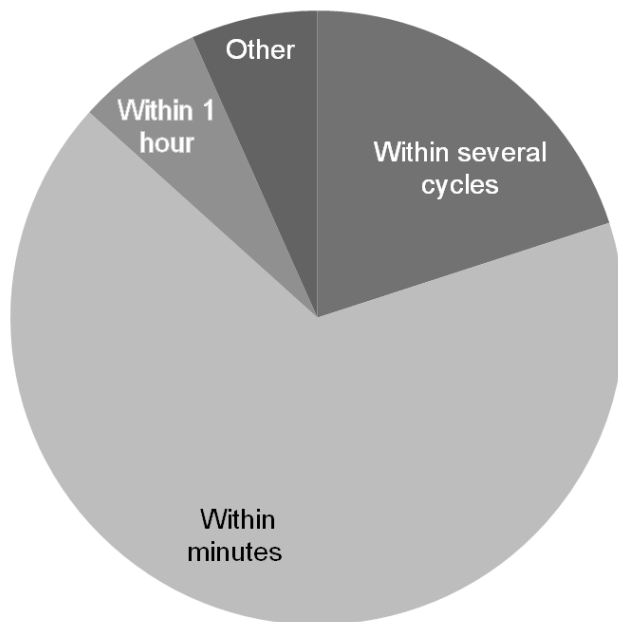
Figure 2.58. Responses considering what would be a useful time frame for automated demand response activities. The "Other" response was "*Depends on individual load and situation*". (*N*=15)

Voltage Level for Adaptive and Self-healing Technologies
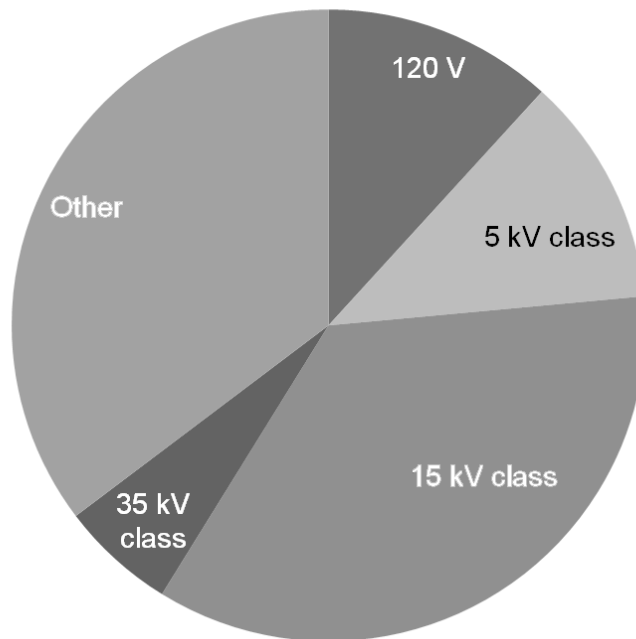
Figure 2.59. Responses to which voltage level adaptive and self-healing technologies will be adopted at. Two of the "Other" responses were variations on "All of the Above." The remaining responses were "*Primary level typically at 12, 17, 21 and 34 kV*", "*15 kV class and above*", and "*25 kV class*". (*N*=17)
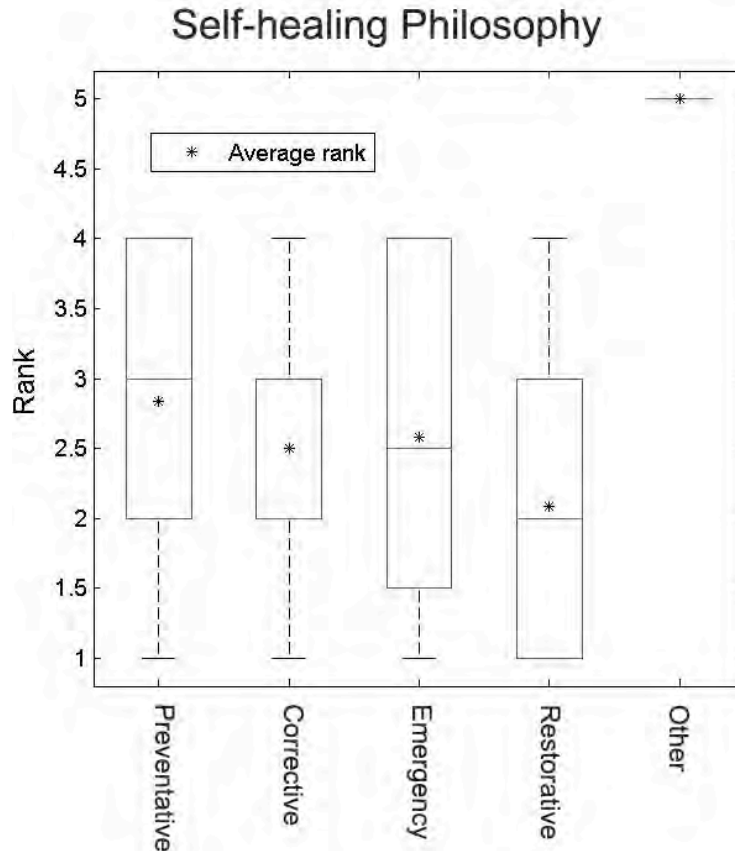
Figure 2.60. A box plot of the ranks of the philosophies of self-healing relative to one another. A rank of '1' is the most important, while a rank of '5' is the least important. (N=12)

Table 2.18
Relative rankings of the philosophies of self-healing. A rank of '1' is the most important, while a rank of '5' is the least important. These results are shown in a box plot in Fig. 2.60.

Self-healing philosophy	Rank	
	AV	SD
Preventative	2.83	1.19
Corrective	2.50	0.90
Emergency	2.58	1.24
Restorative	2.08	1.16
Other	5.00	0.00
N = 12		

How Should the System Heal Itself?
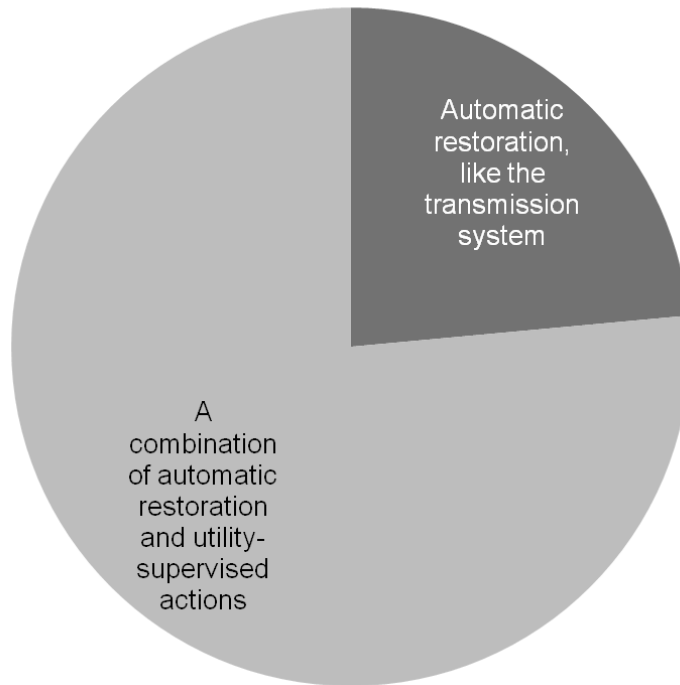
Figure 2.61. Responses considering how self-healing should occur. (*N*=17)

Target ASAI of Distribution System
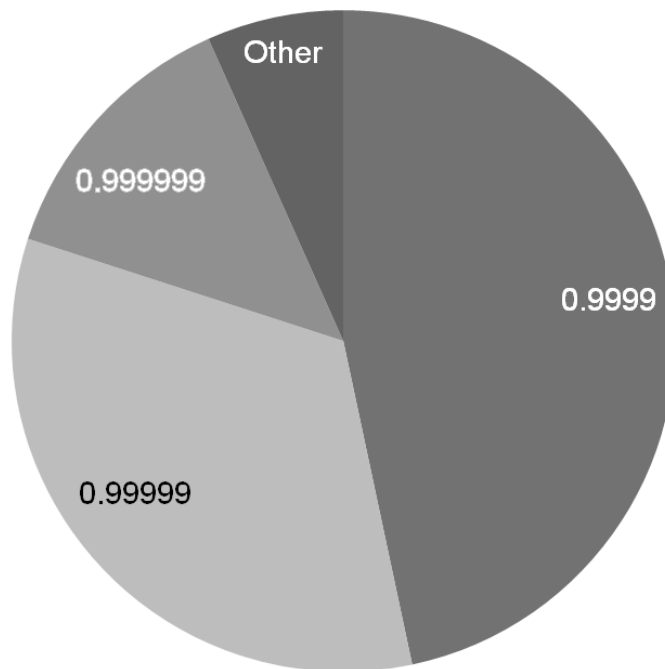
Figure 2.62. The target ASAI for distribution system reliability. The "Other" response was "*Based upon cost*". (*N*=15)

Timeframe of Self-healing Activation
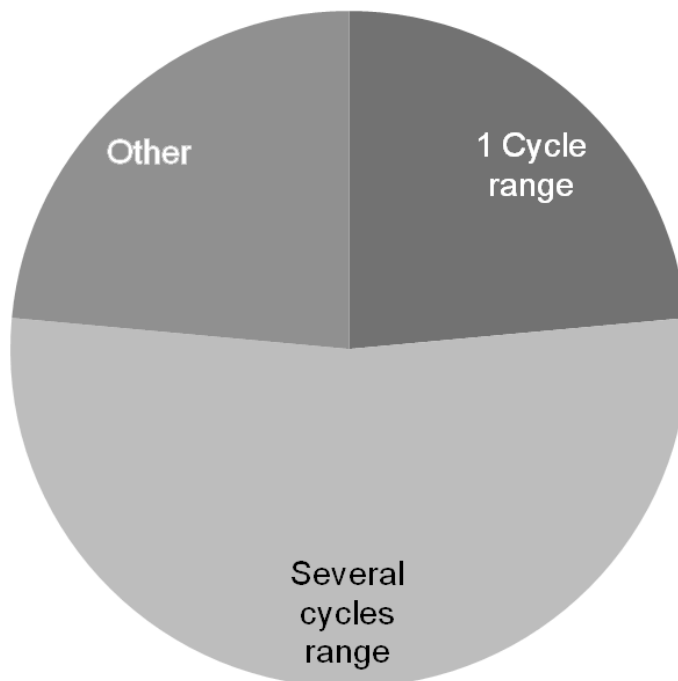
Figure 2.63. The timeframe in which self-healing activities should activate. The "Other" responses were *"Several seconds"*, *"Could be in second"*, *"One minute"*. (*N*=17)

Restoration Timeframe for Self-healing
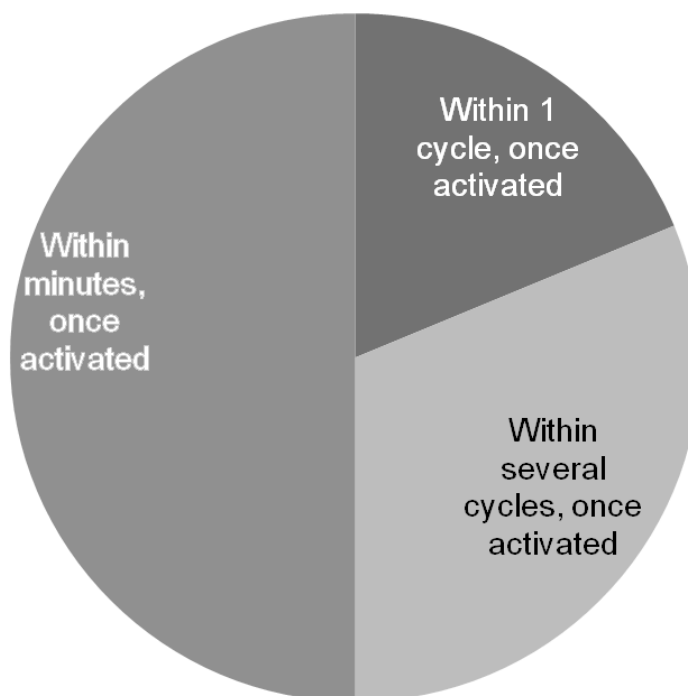
Figure 2.64. The expected timeframe for self-healing technologies to be successful, after activation. (*N*=16)
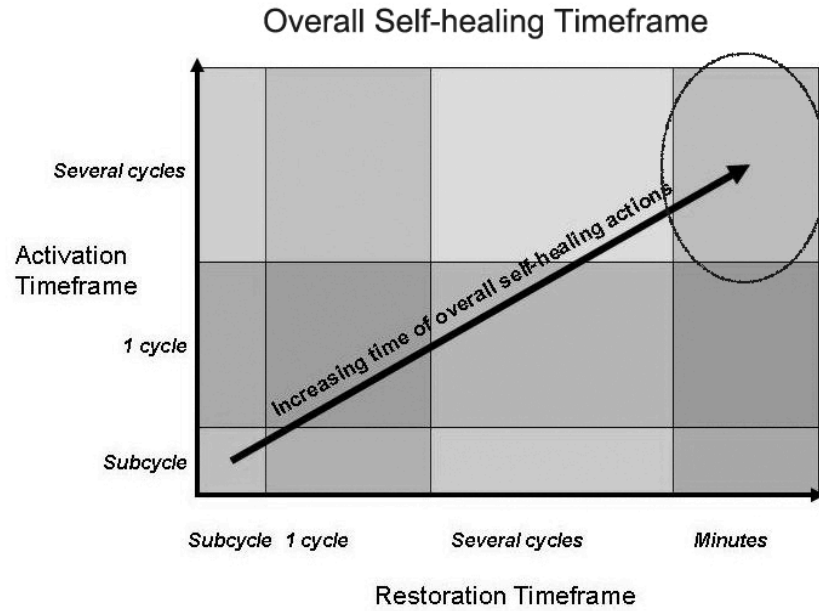
Figure 2.65. The overall timeframe for self-healing, considering both activation timeframe (y-axis) and the restoration timeframe (x-axis). The intersection of survey responses considering activation and restoration timeframes is circled.
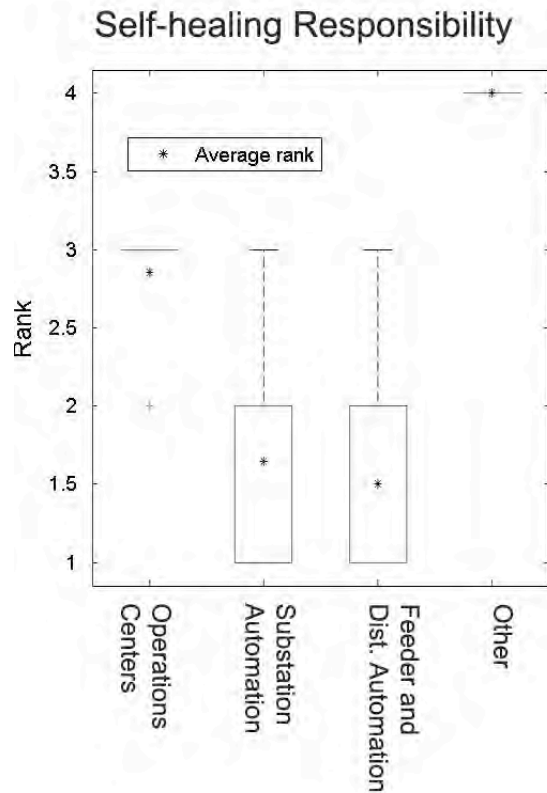
Figure 2.66. A box plot of responses considering where the responsibility for self-healing should lie. "Substation automation" corresponds to smart substations and "Feeder and distribution automation" corresponds to smart feeders. A rank of '1' is the most important, while a rank of '4' is the least important. (N=14)

Table 2.19
Relative rankings of locations where the responsibility for self-healing could lie. A rank of '1' is the most important, while a rank of '4' is the least important. These results are shown in a box plot in Fig. 2.66.

Location	Rank	
	AV	SD
Operation centers	2.86	0.36
Substation automation (e.g. "smart" substations)	1.64	0.63
Feeder and distribution automation (e.g. "smart" feeders)	1.50	0.65
Other	4.00	0.00
N = 14		
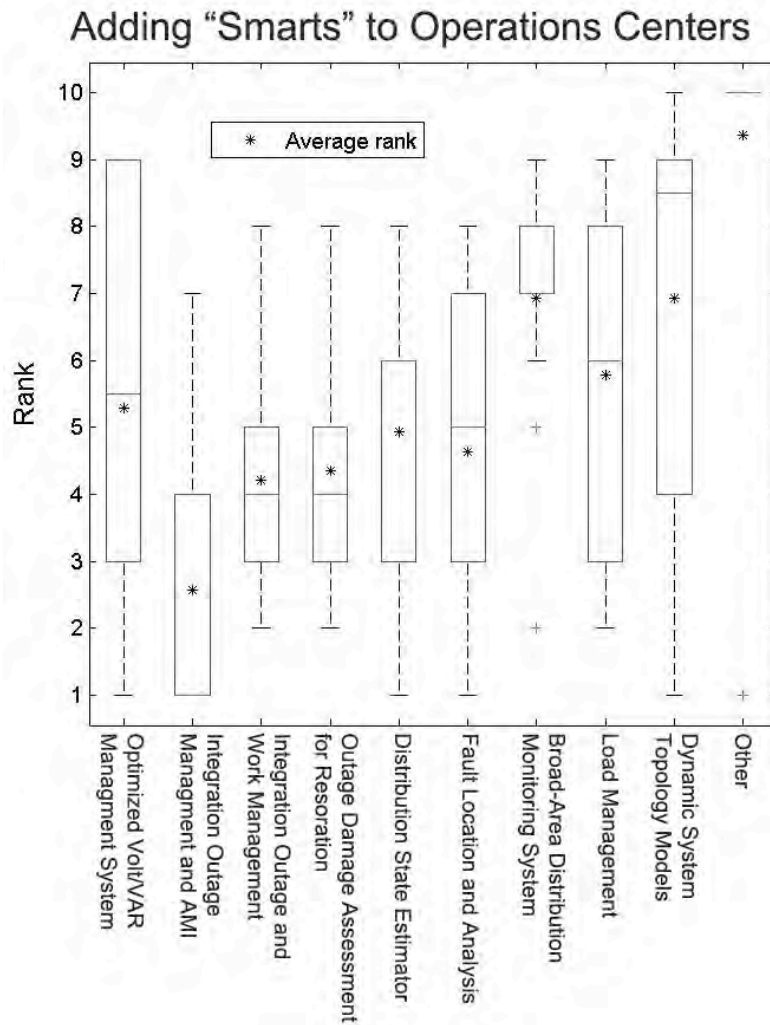
Figure 2.67. Box plot of the ranking of technologies to add "smarts" to operations centers. A rank of '1' is the most important, while a rank of '10' is the least important. (N=14)

Table 2.20

Relative rankings of technologies to add "smarts" to operations centers. A rank of '1' is the most important and a rank of '10' is the least. These results are shown in a box plot in Fig. 2.67.

Technology	Rank	
	AV	SD
Optimized Volt/VAR management system	2.29	2.89
Integrated outage management system and AMI	2.57	2.06
Integrated outage management system and work management system	4.21	1.58
Outage damage assessment for restoration	4.36	1.78
Distribution state estimator	4.93	2.27
Fault location and analysis	4.64	2.31
Broad-area distribution monitoring system	6.93	1.73
Load management	5.79	2.81
Dynamic system topology models (software)	6.93	3.05
Other ✓ *Real time prices for consumers*	9.36	2.41
N = 14		

Table 2.21

Relative rankings of technologies to add "smarts" to feeder and distribution automation. A rank of '1' is the most important, while a rank of '9' is the least important. These results are shown in a box plot in Fig. 2.68.

Technology	Rank	
	AV	SD
Smart feeder automation (microprocessor based with communication capability)	1.82	1.25
Feeder condition monitoring to improve reliability	4.45	2.16
Automated adaptive relaying	4.27	1.90
Feeder load transfer (switching for demand response / load management)	4.18	1.78
Automated feeder reconfiguration (via "smart" switching) for loss reduction or overload relief	3.91	2.21
Feeder fault detection and diagnostics	4.36	2.11
Feeder equipment failure detection (i.e. distribution-level reclosers)	5.81	1.99
Voltage regulator with communication capability	7.18	1.25
Other	9.00	0.00
N = 14		
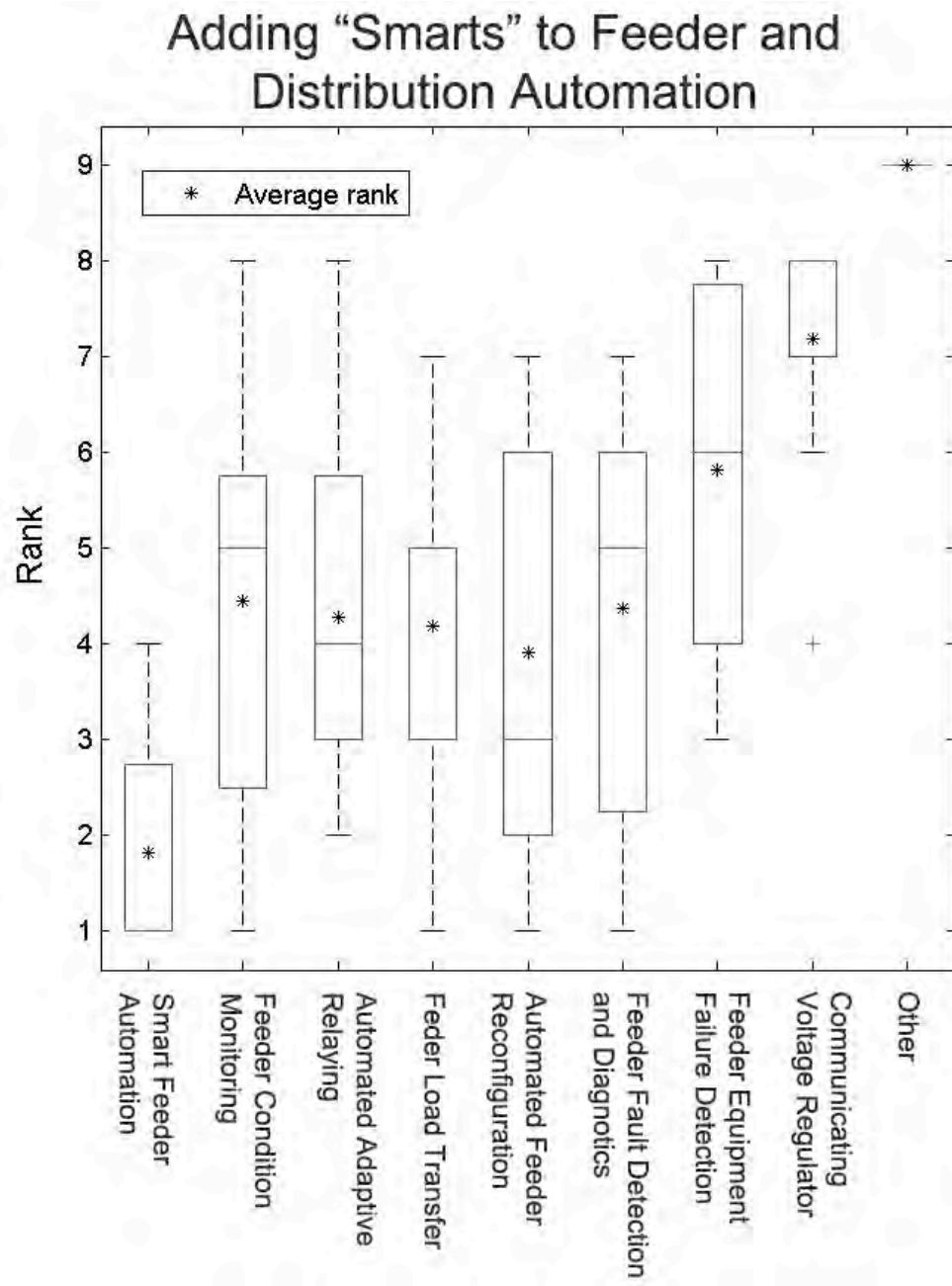
Figure 2.68. A box plot of the ranks of technologies to add "smarts" to feeder and distribution automation. A rank of '1' is the most important, while a rank of '9' is the least important. (N=14)
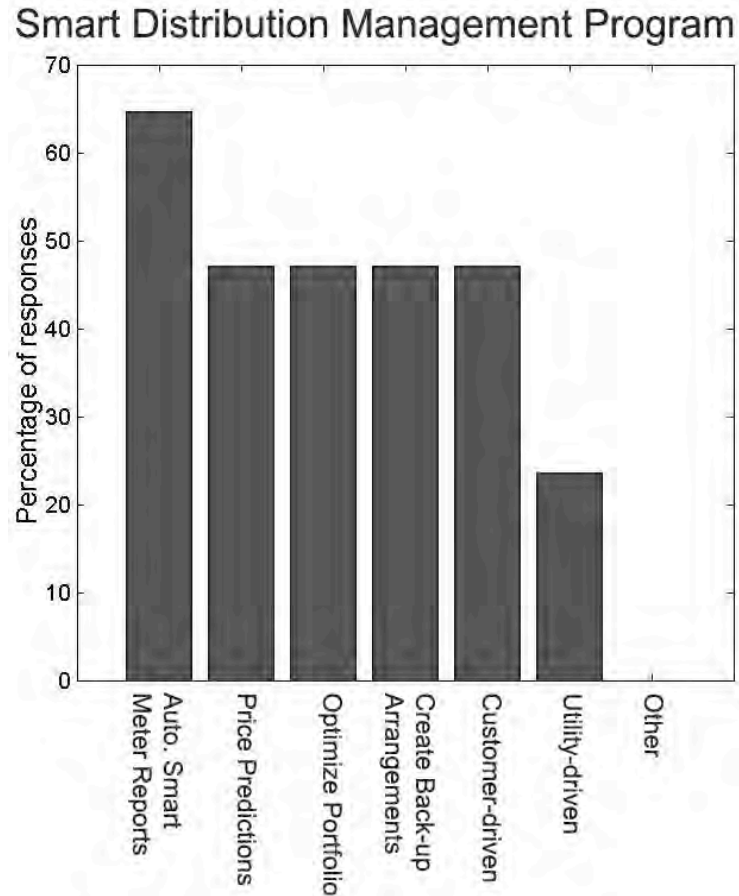
Figure 2.69. Responses of the functionality of a smart distribution management system. (N=17)
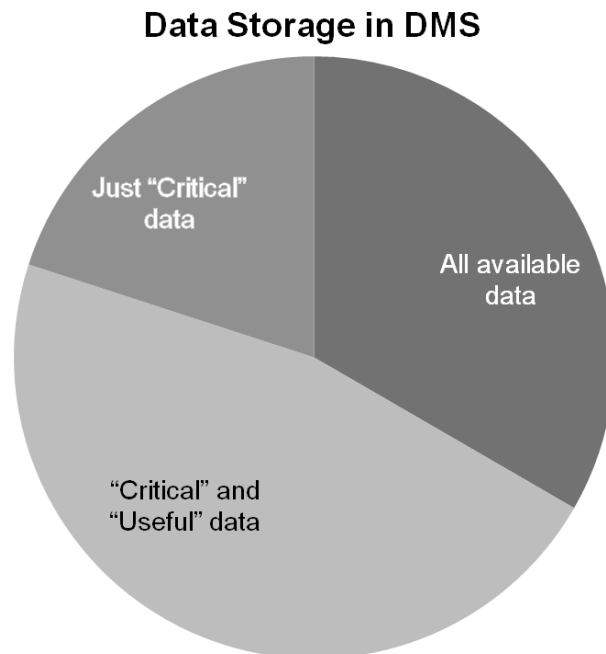
Figure 2.70. Responses regarding which types of data should be stored in a smart distribution management system. (N=15)

Location of Data Storage Server

At the location of collection, on the utility-side of the smart-meter

At the location of collection, on the customer-side of the smart-meter

At the utility center of operations

At data-collection centers distributed throughout the system (i.e. a substation)
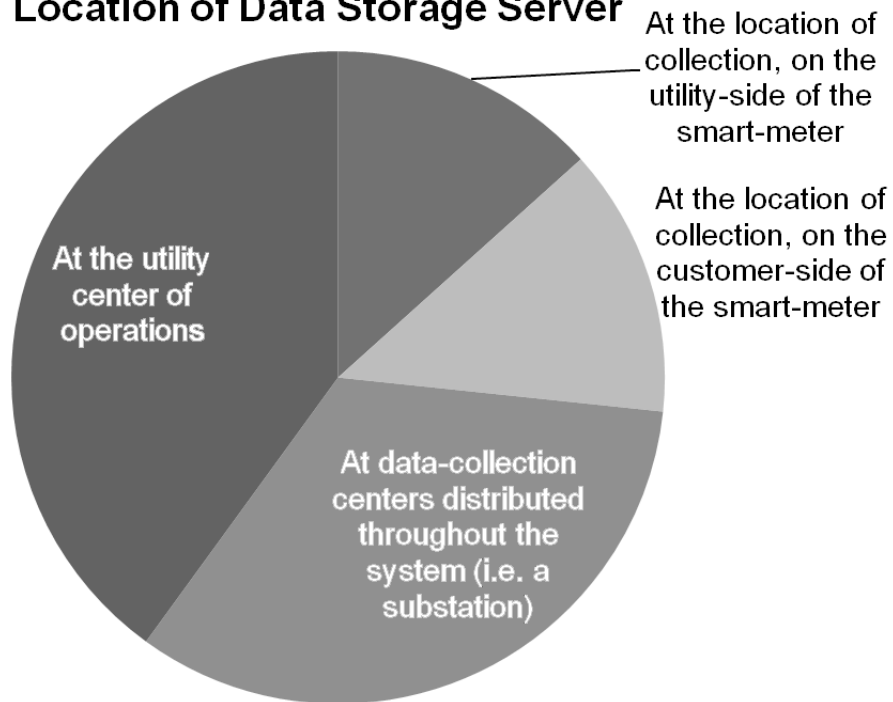
Figure 2.71. Responses to where the data storage should be located for a smart distribution system. (N=15)

Types of Smart Appliances

Other

Thermal devices

Programmable devices

Smart-circuit devices
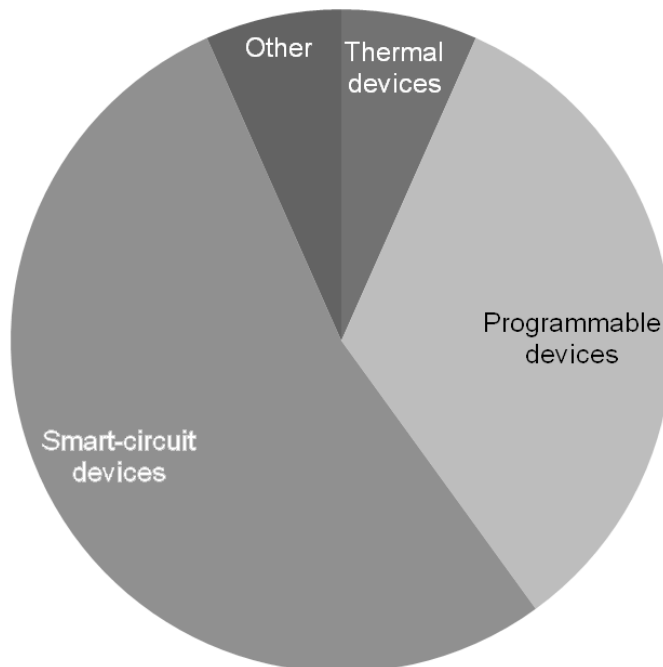
Figure 2.72. Responses considering the desired type of smart appliances. The "Other" response was "*Devices with 2 way communication capabilities to respond to system signal*". (N=15)
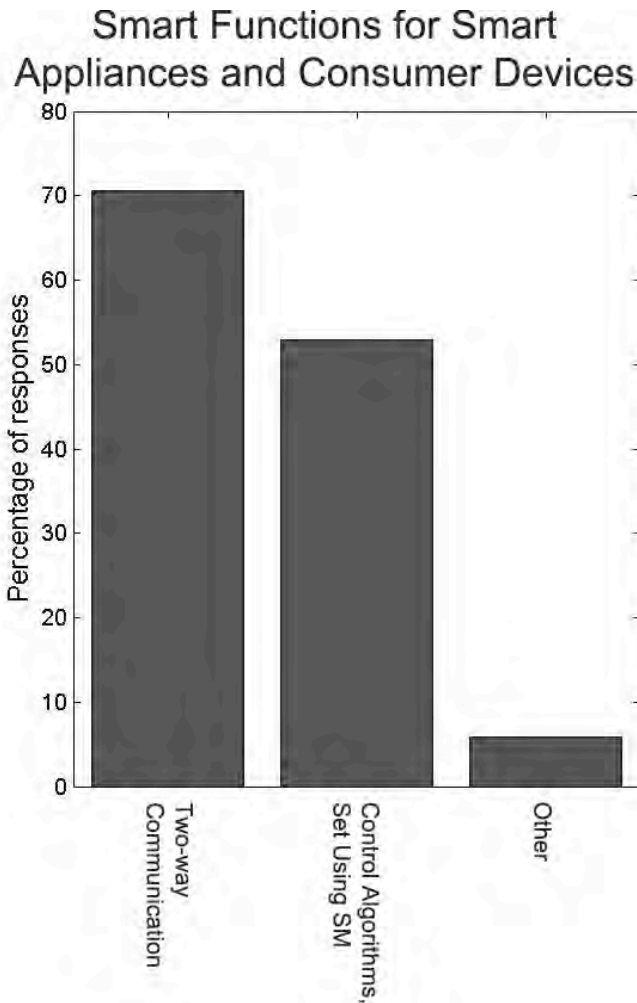
Figure 2.73. The expected smart functionality of smart appliances and consumer devices. The "Other" response was "*Control; algorithms that react to messages passed via the smart meter [sic]*". (*N*=17)

iii.   **Integrates massively deployed sensors and smart meters**. Digital sensors with incorporated intelligence are used to monitor the directions and amounts of power flow and the locations and usage patterns of DER. The sensors are expected to be located at the 15 kV class and will communicate updates at least once per minute. The sensors will be able to engage in two-way meshed communications and be enabled with control algorithms to automatically react to measurements. The smart meter acts as a communications link and a local control system and its functionality includes 1) two-way communications with the utility, as well as other devices, such as DER or CDMS or LEMS, 2) real-time reads, 3) automatic time synchronization, 4) tamper detection alarms, 5) current and voltage profiling, and 6) the capability to download and store time-of-use schedules.

Smart Appliance Control System

Other

Programmable controls on the device

Demand response/ load management program

LEMS

Smart metering
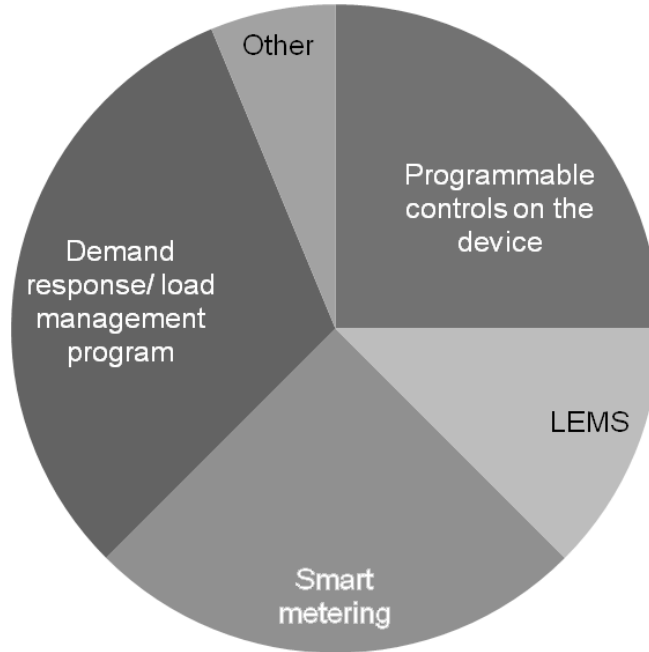
Figure 2.74. Responses concerning how smart appliances should be controlled. The "Other" response was "*I don't know*". (*N*=16)

Voltage Level of Islanding Ability

120 V

480 V

Other

5 kV class

35 kV class

15 kV class
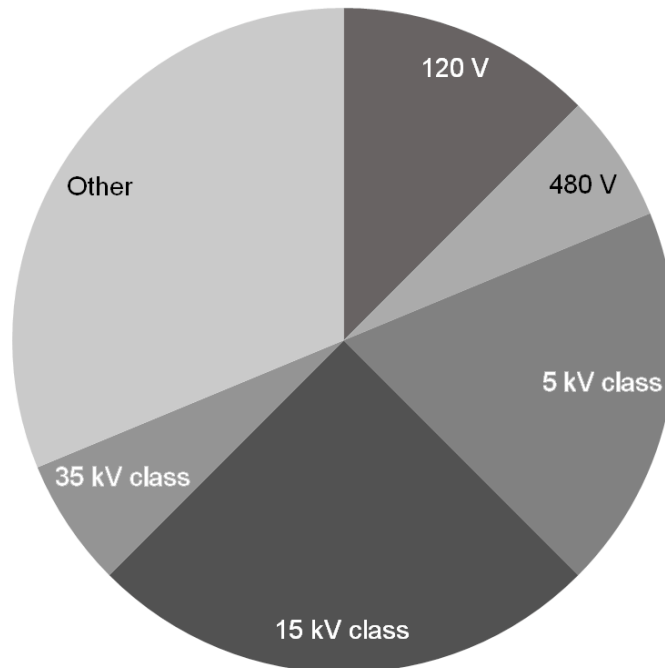
Figure 2.75. Responses regarding the voltage level of islanding ability. The "Other" responses were "Service voltage", "Primary voltage which is typically at 12, 17, 21 and 34 kV", "I am not qualified to answer questions about islands", "As required", and "25 kV class". (N=16)
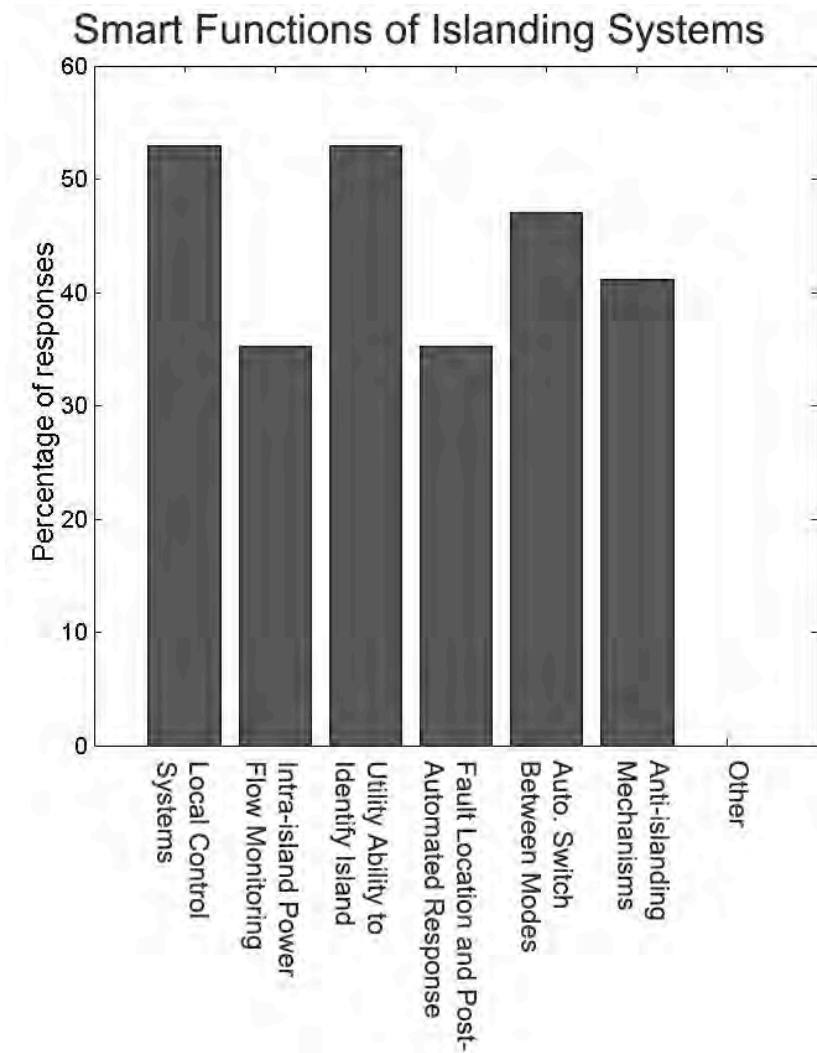
Figure 2.76. Percentages of the responses about the smart functions of islanding systems. (N=17)

iv. **Enables consumer participation in demand response** through the widespread use of dynamic pricing, with real-time signals. The utility gives the consumer limited and total control of load and generation. Demand response will engage within minutes.

v. **Uses adaptive and self-healing technologies** primarily integrated at the 15 kV class. The technologies should be able to engage in all four types of self-healing: restorative, emergency, corrective, and preventative. Self-healing will be achieved through a combination of automatic restoration and utility-supervised actions. Distribution-level self-healing actions should enable the system reliability to reach between 0.9999 (4 nines) and 0.99999 (5 nines). Technologies will activate within several cycles and will restore the system within minutes, once activated. Smart feeders will carry the responsibility for self-healing actions and will be enabled by microprocessor-based feeder automation with communications capability.

vi. **Makes use of advanced tools** (including visualization, analysis, and simulation) to streamline routine operations. A "smart" DMS will be customer-driven with the ability to 1) automatically report time-stamped smart meter measurements to the utility and use the data to plan and/or predict future usage, 2) use energy price predictions to plan future usage, 3) optimize DER and load portfolios, and 4) create back-up arrangements as contingency plans for the failure of specific components. A utility-driven DMS would store "critical" and "useful" data, with data storage locations distributed throughout substations and/or centralized at the utility center of operations.

vii. **Integrates smart appliances and consumer devices**. Smart appliances will be smart-circuit devices and programmable devices. These devices will be two-way communication enabled and will possess control algorithms.

Figure 2.77. Responses considering how the switch should be made to islanded operation. The "Other" response was "all should be considered". (N=14)
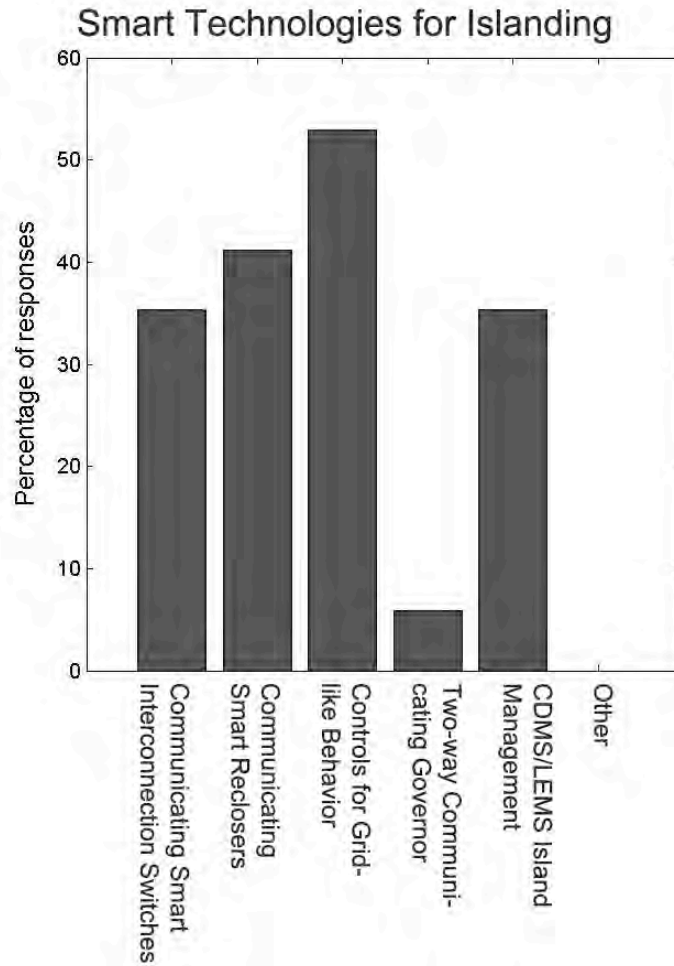
Figure 2.78. Percentages of responses regarding smart technologies for islanding. (N=17)

viii. **Possesses the ability to operate in either islanded or grid-connected mode**. A system with islanding potential should have control systems for local regulation of voltage, real power balance and reactive power balance. The utility should be able to identify islands. The ability to island would be facilitated by the implementation of controls for grid-like behavior (i.e. measuring frequency and voltage droop to control real and reactive power outputs).

2.5 Applicability

The results of this survey may be applied in two main ways: determining composition of simulation systems and determining areas where future research can be focused. In the former, results of the composition of DER have been applied to distribution test systems described in Chapter 4. Furthermore, the optimization techniques, also discussed in Chapter 4, attempt to improve the ASAI by decreasing the energy not supplied.

Any area in the survey where there was no or limited consensus may be an area for future research, although further investigation may be required into areas where there is a consensus, perhaps using the survey results as a starting point or using the survey results to guide project development. Recently, the GridWise Alliance issued a report to discuss current gaps in smart grid knowledge, with a focus on demonstration projects [105]. Some of the areas discussed included the role of distributed agents, the effect of alternative rate structures, the regulatory challenges associated with incorporating RE resources and environmental incentives, and communications questions, such as communication flow over the grid system and maintenance of privacy [105]. However, results from the smart distribution survey described in this chapter indicate that it is possible that industry members are frustrated with current levels of regulation, based on responses such as "*RPS causes uneconomic investment*" and the low importance of "regulatory adjustments" and "policies and subsidies" to opening up new opportunities in a smart distribution system. Other areas identified by the GridWise report align strongly with areas found by the survey that require further investigation, such as communications, control, and the role of DER.

Some of the areas requiring future research are shown in Fig. 2.79. The inside of the ellipse represents the categories of future research (which align with the GridWise report) and the outside circle explains specific areas within those categories identified by the smart distribution survey. Inner-circle topics are control, communications, the role of DER, and self-healing. Specific topics in the outside circle include consumer control at the PCC, data storage, sensor applications, scheduling of DER, and LEMS operating functions. An example of the applicability of LEMS to a customer-driven RE resource deployment, in the perspective of the smart grid, appears in [106]. Many of the items addressed in this survey are limited to a functional level; to truly create a smart distribution system will require much work into the finer details of technology implementation, such as data encryption techniques and data transfer algorithms.
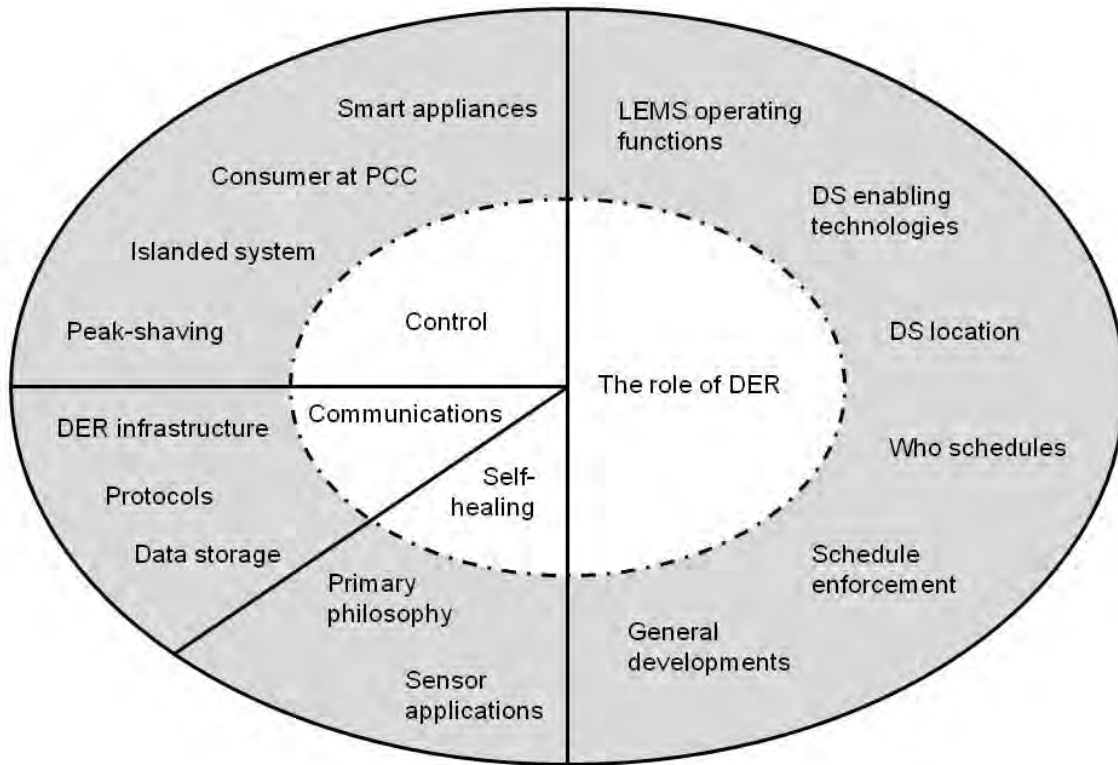
Figure 2.79. Areas of a smart distribution system which require further investigation. The inner circle contains the categories, which align with areas identified by the GridWise Alliance report [105], while the outer circle describes specific areas of each category.

CHAPTER 3

DISTRIBUTION SYSTEM PLANNING AND MODELING

The work in this report focuses on distribution system planning related to adding networked feeders to improve reliability. In this chapter, reliability evaluation will be discussed in Section 3.1. The modeling characteristics of DG sources will be discussed in Section 3.2, followed by an explanation of the feeder addition problem in Section 3.3. Next, the single objective and multi-objective optimization formulations for the feeder addition problem will be discussed in Section 3.4 and 3.5, respectively. Section 3.6 explains a heuristic technique applied to the feeder addition problem, while Section 3.7 discusses the application of a GA to the same problem. Other distribution system planning concerns were discussed in Section 1.4.2, titled "Distribution system engineering".

3.1 Reliability evaluation

Reliability evaluation may either address the actual behavior of a system or the expected behavior of a system under a given set of scenarios. Monitoring the actual behavior of a system allows one to use statistical measures of reliability, such as system availability, number of incidents, and number of hours of interruptions [80]. However, it should be noted that one measure is often not enough to fully characterize the reliability behavior of a system, since statistical evaluations often result in average or expected values [80]. Some statistical reliability indices will be discussed and defined in Section 3.1.1.

Although the argument for probabilistic measures of reliability was first made in the 1930s, it is common industry practice to use deterministic approaches for reliability evaluations in planning and operations [80]. Examples of deterministic approaches to evaluating system adequacy are load balancing and N-1 contingency evaluations [107].

Multi-state systems are those for which reliability cannot be described as operation versus failure; there is the possibility of partial failure that could result in partial output [108]. The four major methods of evaluation are Boolean, stochastic (which include Markov and semi-Markov approaches), universal generation function, and Monte Carlo simulation [108]. The electric power system may be considered a multi-state system due to its complexity and the possibility of partial system operation. Power system reliability has been evaluated stochastically by the use of simulations [109], such as Monte Carlo [110-112] or the cumulant method [113].

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3.1.1 *Common distribution system reliability indices*

The indices described in this section are consumer or end-user oriented indices, and depend to different degrees on the number of consumers affected, the total number of consumers, the average load connected, and the duration of interruption [80]. These values often depend on utility reporting procedures, such as how an end-user is defined, whether by a single physical location or the number of meters [114]. The three indices described here are the three most popular customer-oriented indices, as found by an Electric Power Research Institute (EPRI) report cited in [80]. The system average interruption duration index (SAIDI) is defined as the average interruption time per customer, as follows from [80]:

$$SAIDI = \frac{total\ number\ of\ customer\ interruptions}{total\ number\ of\ customers\ served} \qquad (3.1)$$

The system average interruption frequency index (SAIFI) is defined similarly to SAIDI, but describes how often interruptions occur per customer, on average [80]:

$$SAIFI = \frac{sum\ of\ customer\ interruption\ durations}{total\ number\ of\ customers} \qquad (3.2)$$

The ASAI is defined as the average system availability [80]:

$$ASAI = \frac{customer\ hours\ of\ available\ service}{customer\ hours\ demanded} \qquad (3.3)$$

and it describes the time, as a fraction of a year, for which the system is available for customer use.

Other statistical indices attempt to describe different interruption characteristics and types. Examples of such indices include the momentary average interruption frequency index (MAIFI) and the system average RMS variation frequency index (SARFI), where RMS is the root-mean-square [114]. It has been found that increasing the performance of a system with respect to SAIDI or SAIFI will actually cause another reliability index, such as MAIFI, to decrease [78].

3.1.2 *Other reliability indices*

Load- and energy-related reliability indices may also be used to evaluate system performance [80]. One type of load-related index is the energy not supplied (ENS) index and it is defined as follows [80]:

$$ENS = \sum L_i U_i \qquad (3.4)$$

where L_i is the average load connected and U_i is the annual outage time at load point i.

3.1.3 *Evaluating reliability*

The reliability indices described in this section may be used to evaluate past system performance, which is more common, and future system performance [80]. To evaluate the reliability of the test systems used in this report, ASAI and ENS were used. The base case ENS was estimated using ASAI as described below,

$$ENS = 8760 * (1 - ASAI) \sum L_i$$

(3.5)

where 8760 is the number of hours in a year. For the purposes on evaluation, the system *ASAI* was assumed to be the overall system average of 0.999375 [78]. The evaluation of *ENS* for the optimization procedure will be discussed in Sections 3.4 and 3.5.

3.2 Renewable energy resources

The use of the RE resources is promoted in many federal initiatives, as well as in state RPS mandates. The results of the survey, which sought a definition of a smart distribution system (Chapter 2), showed that participants anticipated that 10-19% of generation would be met via RE resources. With 25% of new DGs in the system expected to be RE resources, many RE resources will be located at the distribution level. The top five RE resource technologies identified by the survey were photovoltaics (PV), CHP, biomass/biofuels, fuel cells, and wind, respectively, all of which are applicable at the distribution level. For the purposes of this report, it will be assumed that the RE resources that make up the DER will be PV, fuel cells, and wind. The wind resources are assumed to be land-based. An example of a small-scale, residential wind turbine is the Skystream 3.7, [115], the development of which was aided by National Renewable Energy Laboratory (NREL) [116].

The incorporation of RE resources requires extensive studies and power electronic technologies. A discussion of the integration of alternative sources of energy is given in [117] and a discussion of the power quality implications of DG is provided in [78]. Fuel cells and DGs fueled by biofuels are dispatchable technologies. On the other hand, PV and wind sources are non-dispatchable because they depend on fuel sources that are variable, while wind in particular may be quite intermittent.

The output of PV cells depends on solar irradiance, ambient temperature, the size of the cell, and the efficiency of the unit [118]. The output power of wind turbines is proportional to the cube of the wind speed, but the output also depends on unit design and efficiency [119, 120]. The maximum output of PV cells occurs during the day when the sun is shining, while the maximum output of wind turbines tends to be during the nighttime, when winds are high.

In [121], a binomial probability distribution function was used to represent the solar output, as well as the assumption that the solar output could be represented as a multi-state model with either two or five output states as an approximation to the probability distribution function. Wind power output has been tied to the availability of the wind itself using a multi-state stochastic model of output [111]. Another approach has focused on the stochastic representation of the prime mover at each generation site, as well as the comonotonicity, or dependence, of different generators in the system, for example, wind turbines located near one another will have similar output characteristics [122].

Using stochastic models for solar and wind generation necessitates the need for stochastic power flows, as well as stochastic load profiles. To simplify the system, it is proposed in this report that the capacity factor of the generators be used to represent their power output. The work in this report is modeling the aggregate outage time for the entire year, without analyzing each separate outage event. It is also assumed that each outage event may occur at random, for an unknown amount of time, adding up the total yearly outage time. Therefore, it is reasonable that the capacity factor will likely represent the output of the PV and wind generators over the course of the year, and also for the subset of outage times.

The capacity factor of a generator is the ratio of the energy actually produced over a given time period, compared to the energy that could have been produced over that time period if the unit had been operating at rated power for that same time period [119]. The capacity factor of a wind turbine is approximately 25% [119], depending on the wind resource available at the location of installation. According to [123], the PV capacity factor may vary from 16% in Seattle, WA to 36% in El Paso, TX; the value for Boulder, CO is 30%, which will be used in this report. As a corollary to this assumption, it is presupposed that the power electronics pertaining to the control of the DGs are capable of limiting power output if supply exceeds demand under islanded conditions.

Based on the generation mix identified by the survey, the total system DER power output is given by

$$P_{out} = \mathcal{R}_{RE} * \mathcal{CF}_{RE} + (1 - \mathcal{CF}_{RE}) * 0.15\mathcal{L}_i + \mathcal{R}_{CDG} * \mathcal{CF}_{CDG} \tag{3.6}$$

where the $\mathcal{R}$ represents the total rating of the source listed in the subscript: *RE* for RE resources and *CDG* for conventional (or, non-renewable) DG sources. $\mathcal{CF}$ indicates the capacity factor of the subscripted source. The $\mathcal{L}_i$ represents the average installed load at the load point *i*, where the RE resource backed by storage is installed. This equation was developed from the generation mix specified from survey participants. The first term corresponds to the RE resource generation, while the second term describes the contribution of RE resources that are supported by DS, whose output is 15% of the total load at the installation point based on survey responses. The contribution of DS is multiplied by (1 – $\mathcal{CF}$) because

DS may only contribute when RE resources are not operating. The third term is the power output of the CDGs. The rating of the CDG resource is given by $\mathcal{R}_{CDG}=\mathcal{R}-\mathcal{R}_{RE}$, which is the rating of the RE resources in the system subtracted from the total DG rating of the system. The total DG rating is 80% of the total system load, as determined by the survey responses described in Chapter 2. In this report, the P_{out} is aggregated to known points throughout the test system. The application of this equation will be described in more detail in Chapter 4, during the discussion of the RBTS in Section 4.3.

3.3 Feeder additions

The electric power system is comprised of many series and parallel components, in addition to complex arrangements [79, 80]; some of the arrangements of power system components are depicted in Figure 3.1, which was created using [79]. There are four ways to improve the reliability of a multi-state system (according to [108]):

      i.   increase redundancy,

     ii.   optimal adjustment of system parameters,

   iii.   improve the availability or performance of the system components, and

   iv.   a combination of (i) – (iii).

The feeder addition problem attempts to improve reliability by increasing redundancy in a system, especially one that is disconnected from the area electric power system (EPS). Isolated feeders may only rely on generation from sources that are connected to that feeder, while the transmission system is able to draw from many different generators, due to the network characteristics of transmission lines. As the distribution system develops into a smart distribution system, an increasing number of DGs will be present and the reliability will not be necessarily dependent on generation coming from the area EPS. In the scenario of evolving distribution systems, as guided by the SGI, the reliability may be improved by adding more redundancy in the connections between local load points and nearby DGs – as the penetration of DG increases, the distribution system may begin to resemble a small transmission system [3], whose interconnected lines are intended to improve reliability. Furthermore, in a system that is networked, the contributions of each DG source are maximized compared to a purely radial system [53].
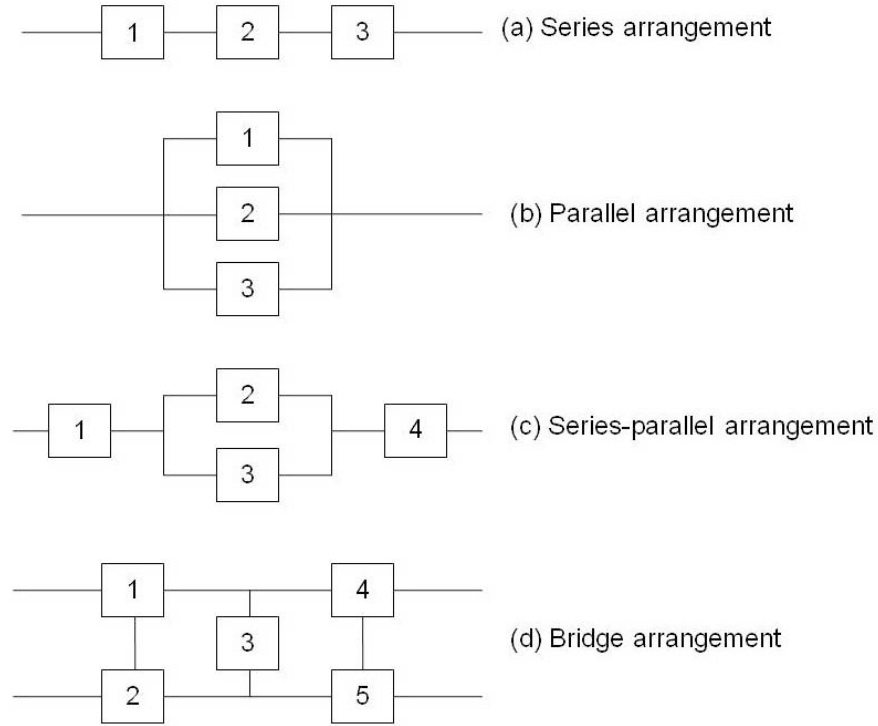
Figure 3.1. Different fundamental arrangements of components comprising the electric power system. This figure was made using [79].

Several assumptions are made in the feeder addition problem, and it is important to identify them before continuing. The distribution system is assumed to be an "emerging distribution system", i.e. it is one that takes into account some characteristics of the smart distribution system, as identified by the survey described in Chapter 2, but also has some legacy components. It is assumed that the protection system allows bi-directional power flow. Any other protection considerations are beyond the scope of this work. Furthermore, safety considerations will not be addressed. It is assumed that all connections between feeders are allowed, i.e. that any permits and rights-of-way have already been established. The cost of available connections depends on the length of the connection and the type of conductor used. If a transformer is required, this will also have an effect on the cost of the connection. It is assumed that the reliability of existing components will not change as a result of the feeder additions and also that the new additions will have similar reliability as the existing components.

The feeder addition problem addressed specifically in this report is: *Given a distribution system with DGs, add networked connections such that the cost of the addition is feasible while improving the reliability and satisfying power flow constraints in islanded mode.* This may be achieved using optimization methods. The next two sections will describe the formulation of the problem as a single objective optimization (Section 3.4) and as a multi-objective optimization (Section 3.5) and discuss the advantages and disadvantages of both approaches.

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3.4 Single objective optimization

An optimization problem comprises an objective function, which measures how well a solution achieves the desired outcome, and a feasible set, which is the set of possible solutions [124]. In the feeder addition problem, the feasible set is limited by the possible connections in the system. It is assumed that new connections may only be made at existing buses, i.e. no buses are added to the system. Another component of optimization problems is the constraints, which limit the solutions based on undesirable outcomes that are not addressed in the objective function [124]. In the formulation of the feeder addition problem, the constraints are related to the maximum project cost and power system operations constraints of voltage variation and line loading.

The single objective optimization may be formulated with either cost or reliability, in the form of ENS, as the objective. If $f(x)$ describes the total cost of the addition, and $h(x)$ is the ENS, the problem may be described using (3.7). The variable x denotes the topology with any additional connections made.

$$\min \ \{ f(x) | \ g(x) = 0, h(x) - h_o < 0 \} \tag{3.7}$$

where $g(x)=0$ indicates that the power flow equations are satisfied to a certain tolerance. This may be read as "minimize the cost of addition x such that the power flow equations are satisfied and the reliability is improved beyond the base value," which is h_o. An alternative formulation shown in (3.8) is to minimize ENS for addition x, while staying within the maximum allowed cost of the project, f_{max}.

$$\min \ \{ h(x) | \ g(x) = 0, f(x) - f_{max} \leq 0 \} \tag{3.8}$$

The solution space of the feeder addition problem is non-convex, due to the discrete nature of building connections between existing buses. Most traditional methods of optimization require a convex space and a differentiable objective function in order to achieve success [124]. Thus, it is difficult to apply these techniques to the feeder addition problem described. The objective functions in (3.7) and (3.8) are non-differentiable because they are discontinuous. The evaluation of $f(x)$ and $h(x)$ are shown below in (3.9) and (3.10).

$$f(x) = \sum_{i=1}^{N_C} C_i X_i \tag{3.9}$$

where C_i is the cost of connection i, N_c is the total number of possible connections and X_i is a binary variable. Equation 3.9 first appeared in [125] © 2010 IEEE. If the binary variable is true ($X_i=1$), then

connection i is made; otherwise, $X_i=0$ and no connection is made. The ENS is modeled for this problem as

$$h(x) = T \sum_{j=1}^{M} P_j \ , \forall P_j \geq 0$$

(3.10)

where T is the outage time, M is the number of slack buses, and P_j is the slack bus output. The slack buses are used to model the energy shortage in the system. In order for the load and generation to balance, the slack bus will absorb or supply generation during a power flow simulation. Since stability is not considered as part of this work, it is assumed that any slack bus output corresponds to load that must be shed, while any slack bus absorption is the amount of generation that must be curtailed. The slack bus output is only considered when it is supplying load, not absorbing generation. As stated before, it is assumed that the generators are able to curtail their output in the face of excess generation, which corresponds to the negative slack bus case.

The solution of a single objective optimization is defined as the global optimum, x^*. A solution point is the global optimum if the value of the objective function, evaluated at x^*, is less than the objective values from all other points in the solution space [52]. If a global optimum exists, it is the "best" solution that satisfies the system constraints. The problem constraints can be explicitly considered to be the following:

$$f(x) \leq f_{max}$$

(3.11)

$$h(x) < h_o$$

(3.12)

$$0.95 \leq V_a \leq 1.05$$

(3.13)

$$S_{ab} \leq 1.00$$

(3.14)

where a are system buses, V_a is the voltage at bus a, and S_{ab} is the branch loading between buses a and b. Equation 3.13 must be satisfied for all buses in the system and (3.14) must be satisfied for all branches in the system. Previously, (3.13) and (3.14) were lumped together as the part of the power flow equations, $g(x)$.

3.5 Multi-objective optimization

In a multi-objective optimization procedure, there may be two or more objective functions. This is useful if, as in the feeder addition problem, more than one quantity is important to achieving the "best" option. However, for a single objective optimization there may be a global optimum for the objective

function, in a multi-objective framework, the concept of an optimum is described by Pareto optimality [52]. A solution is Pareto optimal if for the objectives considered, another solution does not dominate any one of its values of the objective function without becoming "worse" in another objective function [52]. Often, there is a set of points which are non-dominated and comprise the Pareto front and the goal of any multi-objective optimization procedure is to identify this set of points [52].

The objective function for this case becomes a vector function of the separate objective functions:

$$Q(x) = \begin{bmatrix} f(x) \\ h(x) \end{bmatrix} \tag{3.15}$$

where $f(x)$ and $h(x)$ are the cost function and reliability measure, respectively, as described in Section 3.4. The mathematical formulation of the multi-objective optimization is

$$\min \{Q(x) \mid Equations\ (3.11) - (3.14)\ are\ satisfied\} \tag{3.16}$$

Equations 3.11 through 3.14 are the constraints described for the single objective optimization. The cost and reliability constraints still hold true because it would not be desirable to make a feeder addition that was more expensive than the project cost or did not improve the reliability.

Many different objectives besides cost and reliability could be considered in the optimization of the distribution system. The objectives considered in this report are in two groups: i) cost and reliability, for an optimization of two objectives, and ii) cost, reliability, and losses, for an optimization of three objectives. Other areas of potential optimization for the feeder addition problem are shown in Fig. 3.2, originally presented in [125]. The figure highlights major issues associated with distribution engineering and aspects of each issue that arise as the system moves from conventional design and operation to evolutionary design and operation. As mentioned, this report investigates the optimization of reliability and efficiency aspects. No attempt is made to manage the multiple objectives suggested by Fig. 3.2 besides those that have already been mentioned. Two approaches were used to achieve the optimization of the objectives considered in the feeder addition problem: a heuristic technique and the application of genetic algorithms. The heuristic technique, called the "sequential feeder method" was developed specifically for the feeder addition problem.
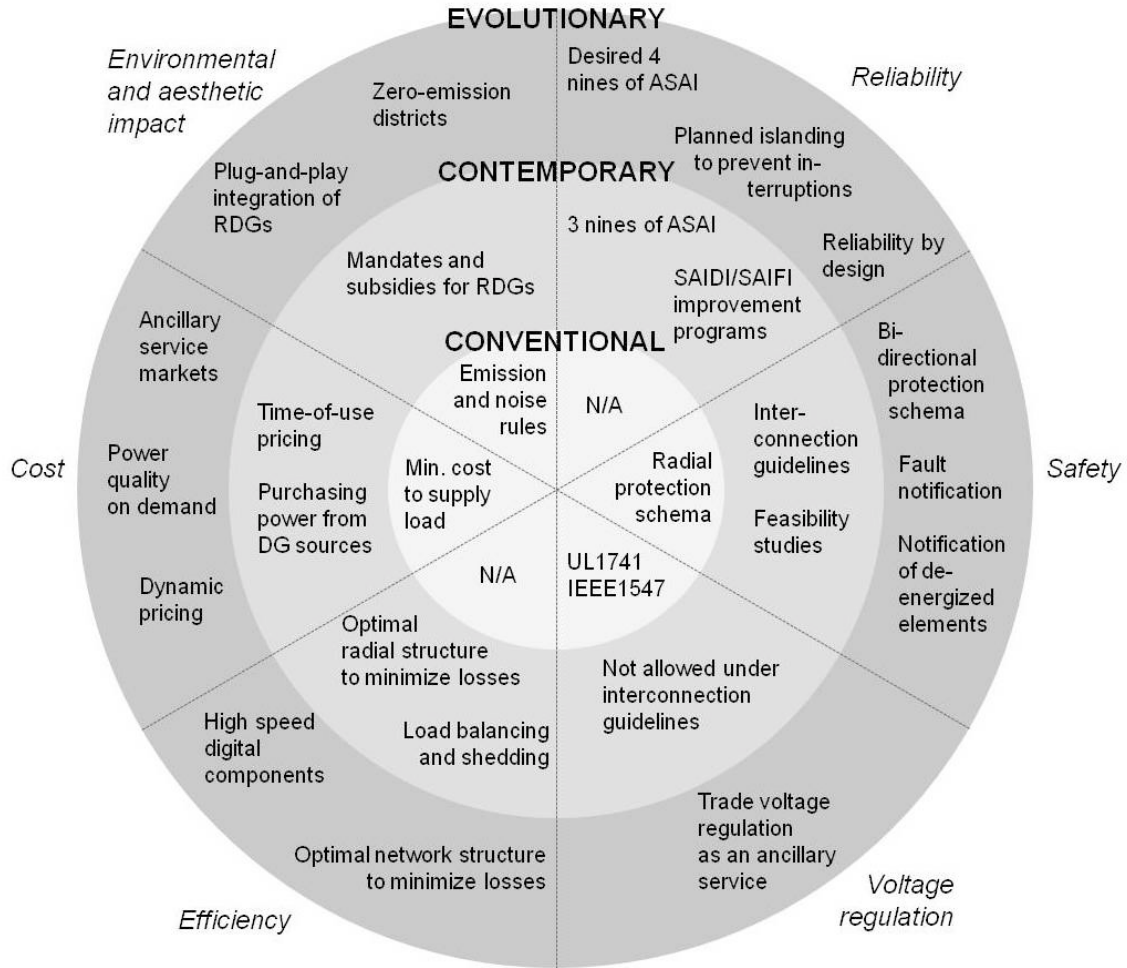
Figure 3.2. Areas of future optimization for power distribution systems, from [125]. Each "slice" represents an area of distribution system engineering. The concentric circles represent concerns that are conventional, contemporary, and evolutionary. © 2010 IEEE.

3.6 Sequential feeder method

An algorithm for redesigning radial distribution systems into partially networked systems is described at this point and is called the "sequential feeder method". This algorithm uses *a priori* information regarding location and rating of RE resource installation, and the system load to optimally balance the cost versus benefits of adding new laterals between distribution feeders is included. The cost being considered is the fixed (i.e., capital) cost of redesign alone, and the benefit is the value of the avoided unserved energy. Most radial distribution systems have laterals which may be connected during certain system events. The sequential feeder method is a means of heuristically moving through the

solution space to evaluate possible results. This method was described by the author in [125] © 2010 IEEE.

Three representations are necessary to complete this optimization problem: the existing topology of the distribution system; the locations and ratings of the DGs; and the existing level of benefit (or reliability). The topology may be represented using a bus connectivity matrix which described the connectivity of a system [125]. The bus connectivity matrix, B, is defined as

$$[B]_{ab} = \begin{cases} 1, if\ bus\ a\ is\ connected\ to\ bus\ b \\ 1, if\ a = b \\ 0, otherwise. \end{cases} \tag{3.17}$$

Any zero entry in B is a possible candidate for a new connection. An example of the B matrix will be provided with the test systems described in Chapter 4.

At this point, consider the upgrading of a distribution circuit – for example, through the addition of lines or through the closing of lateral circuits across several feeders. The number of possibilities is large, even in the case of small systems. Assume that to limit the total number of possible topologies, the added line is *between* existing feeders. Such a requirement allows the partitioning of the B matrix into an array of allowed new connections.

The *sequential feeder approach*, a new heuristic algorithm, is used to solve the stated constrained optimization problem. This approach cannot guarantee optimality, but may be useful if the specified project cost limits the possible additions to one or two new connections. The sequential feeder approach may be applied for more than two connections as well. The iterative sequential feeder approach is conceived such that a new connection in the system results in the maximum improvement in benefit for that iteration.

The flow chart describing this technique is shown in Fig. 3.3. The algorithm begins with gathering the system data and arranging them into matrices and vectors. The possible new lateral connections are examined. The connections are limited to those between different feeders. For each possible connection, the power flow and benefit calculations are completed, and the corresponding cost and improvement in benefit are calculated. If the topology does not yield any improvement in the benefit, then the solution is discarded. After each possible connection has been examined, the solution that offers the best improvement in the benefit is permanently added to the topology. The process is repeated for the addition of a second new connection. The iterative procedure stops when the cost exceeds the total project cost or there is no further improvement in reliability.
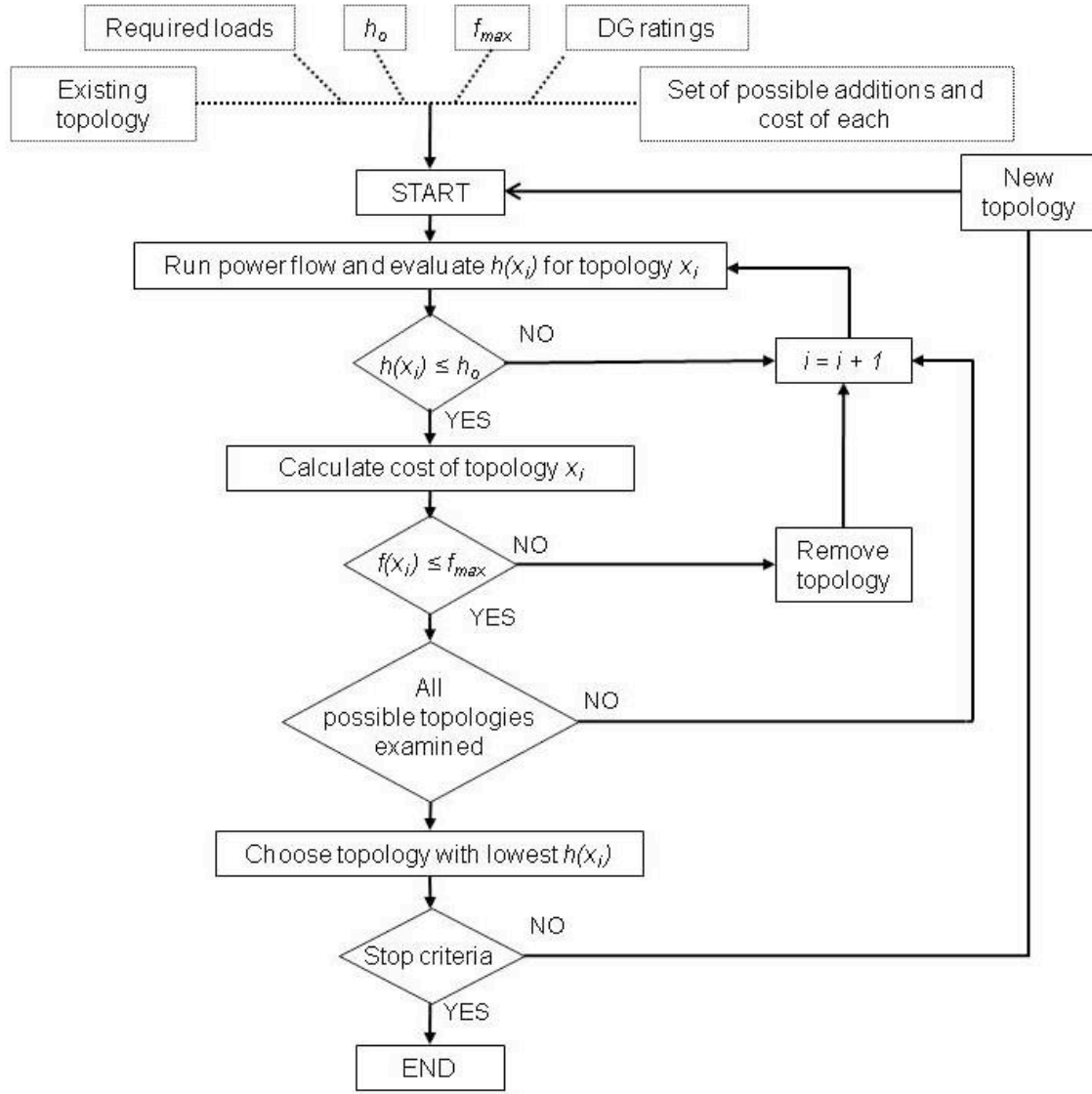
Figure 3.3. A flow chart of the sequential feeder method. The algorithm ends when one of following stop criteria are reached: i) all possible topologies cost more than the maximum project cost and/or ii) there is no further improvement in reliability. Reproduced from [125] © 2010 IEEE.

The mathematical basis for this ordering of objectives is known as lexicographic ordering, which is to minimize the objectives one-by-one, starting with the objective with the highest priority and ending with the objective that has the least priority [52]. The priorities must be decided *a priori* to the optimization procedure, and cannot guarantee optimality [52]. In this case, the highest priority objective is the reliability objective, or *ENS*, with cost as the secondary objective. Due to the lexicographic ordering of the objectives, the heuristic sequential feeder approach may not yield all optimal solutions. If the power flow and reliability requirements are inside the iterative loop of the algorithm, the opportunity to balance cost and reliability is precluded. The solution is simply the new connection that maximizes the benefit during each iteration, which may also be thought of as one exploration during a greedy depth-first

analysis. A greedy depth-first algorithm would look for local optima and search using the local optima generating successors based on the value each brings to the overall objective function. The sequential feeder approach, due to the constraints, does guarantee that the solution improves upon the base case. The fact that the method is sequential means that the truly optimal solutions may never be found.

The sequential feeder approach described here is similar to certain sequential "switching" methods used in heuristic approaches to the loss minimization problem. Reference [38] uses an approach that closes all normally open switches, performs an AC power flow study, and subsequently opens the switch corresponding to the branch with the least power flow. This approach was shown to achieve a near-optimal result.

As the system grows in complexity, the interplay between feeder-to-feeder laterals, the presence of DGs, and unserved loads would also become more complex. Future tasks in solving the evolving complex problem may resort to stochastic optimization techniques that will take into account the spatial and temporal variability – due to intermittent nature of renewable sources – of the problem. The sequential feeder approach is much simpler than the aforementioned methods and for that reason may be useful in systems where the project cost limits the total number of feeders to be added, or the system itself is fairly small.

3.7 Genetic algorithm

A GA is a method of optimization that falls into the category of evolutionary algorithms. These algorithms are named so because they attempt to use concepts from the theory of evolution to aid optimization [52]. The following discussion of the different terminology of GAs was developed using [52]. In a GA, a *population* is comprised of *individuals* or *chromosomes*, each of which encodes a potential solution to the optimization problem. *Evolutionary operators* are used to create individuals which may move to a higher level of fitness and include *mutation*, *recombination*, an example of which is crossover, and *selection* operators. The *fitness function* determines how likely an individual is to survive to the next generation. The fitness function(s) depend(s) on the objective functions but is not necessarily the same.

The basic outline of a GA is given in Fig. 3.4. The step identified with a * corresponds to the fitness function. A brief example of a GA will now be described to illustrate the application of it to a traditional optimization problem. Consider the maximization of the function $= 2$, which is reproduced from [126]. If y is allowed to vary between 0 and 31, as a constraint on the solution space, then the possible values may be encoded as 5-bit strings. This example will focus on the evaluation of a GA for 1 generation.

Step 1: Select an initial population at random from the allowed bit strings (00000 – 11111). This example will use a population of four randomly chosen individuals, as shown in Table 3.1.

Step 2: Decode the *y* values from their bit strings to the form evaluated by the fitness function, also shown in Table 3.1.

Step 3: Evaluate the fitness function, *a(y)* for the population, shown in Table 3.1.
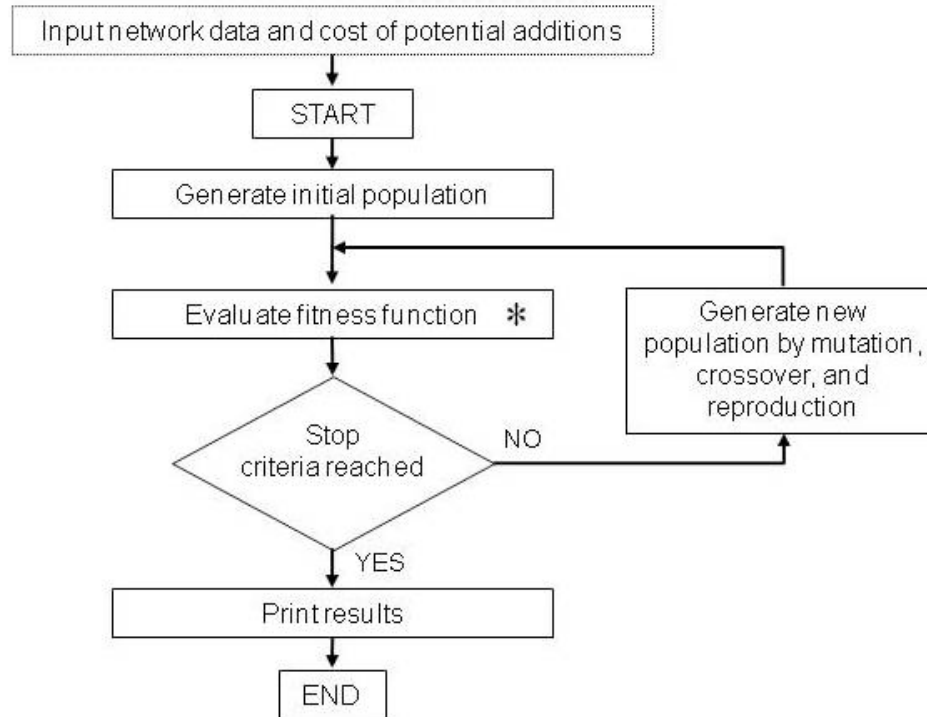
Figure 3.4. Flowchart of the typical GA. The * indicates the evaluation of the fitness function. The population is comprised of individuals, which are represented with a bit string that expresses the system topology.

Table 3.1
Steps 1-3 of a GA, for a simple maximization example

String number	Initial population	*y*-value	*a(y)*
1	01100	12	144
2	11001	25	625
3	00101	5	25
4	10011	19	361

Step 4: Compute the probability of selection via the following equation

$$Prob_i = \frac{a(y)_i}{\sum_{k=1}^{St} a(y)_k}$$

(3.18)

where *St* is the total number of strings in the population and *a(y)ᵢ* is the string that the probability is being calculated for. For example, the denominator is given for all strings as: 144 + 625 + 25 + 361 = 1155, so the probability for string 2 is calculated as *Prob₂= 6251155=0.5411*, which is converted to a percentage by multiplying by 100. The results of this are shown in Table 3.2.

Step 5: Calculate the expected count of the individuals in the population. The expected count is given by (3.19) and is important for determining which individuals will be processed in the mating pool.

$$Expected\ Count_i = \frac{a(y)_i}{Av\ [a(y)]}$$

(3.19)

where the average fitness, *Av [a(y)]*, is given by

$$Av\ [a(y)] = \frac{\sum_{k=1}^{St} a(y)_k}{St}$$

(3.20)

The average value is 1155/4 = 288.75. The expected count of string 2 is then given by *Expected Count₂=625288.75=2.1645*. The results for the whole population are shown in Table 3.2.

Step 6: Calculate the actual count. This is accomplished via a Roulette wheel selection mechanism. The probability of the selection is placed on a wheel (shown in Fig. 3.5), which is spun to determine whether an individual is counted for the selection process. Out of the four individuals, string 2 has a high likelihood of being chosen twice, while strings 1 and 4 have the potential to be chosen once. It is very unlikely that string 3 will be selected for the mating pool. The actual counts are shown in Table 3.2.

Table 3.2
Steps 4-6 of a GA, for a simple maximization example

String number	*Probᵢ*	Expected count	Actual count
1	12.47%	0.4987	1
2	54.11%	2.1645	2
3	2.16%	0.0866	0
4	31.26%	1.2502	1

Roulette wheel selection

■ String 1   ■ String 2   ■ String 3   ■ String 4

12.47%

31.26%

2.16%

54.11%
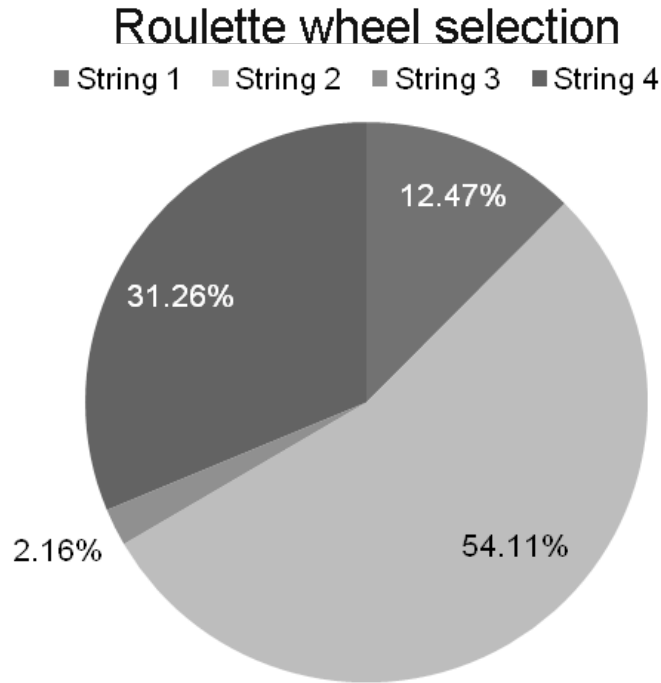
Figure 3.5. Roulette wheel for selection in Step 6.

Step 7: Create the mating pool based on the actual counts. If the actual count is 2, then that string will show up in the mating population twice. The mating pool is shown in Table 3.3 and was populated based on the actual counts shown in Step 6.

Step 8: Single point crossover is used to produce offspring. In this example the probability of crossover is 100%, which means that all of the offspring are produced via crossover. In most applications, the probability is less than 100% because it can be beneficial to preserve some members of the previous generation. Crossover occurs as shown in Fig. 3.6. The offspring via crossover for this example are shown in Table 3.3. The crossover point was chosen randomly.

Step 9: Calculate the y-values and fitness for the offspring, which is shown in Table 3.3.

Step 10: Mutation chromosomes are selected and applied to the offspring population of Step 8. The new generation is created from the mutated offspring. Mutation probabilities are typically low (0.1%) and determine how many chromosomes of an individual will be changed. If the mutation probability were 100%, every bit in an individual would be changed. Mutation is a process that helps to avoid local optima, but if the probability of mutation is too high, the GA begins to act like a random search. The results of the mutation are shown in Table 3.4.

Step 10 ends the processes for the generation. The population at Step 10 becomes the initial population in Step 2 for the next generation. The steps are repeated until one of the following stop criteria are met:

maximum generations, elapsed time, no change in fitness, stall generations, or stall time limit [126]. The stall generations and stall time limit correspond to limits imposed on populations that have no change in fitness. If the stop criterion was a limit of one generation, then the solution would be 29, with a fitness value of 841. As the generations progress, it is expected that the solution would move toward the known solution value of 31, with a fitness value of 961. The discussion of the example is now concluded.

Table 3.3
Steps 7-9 of a GA, for a simple maximization example

Mating pool	Crossover point	Offspring population	y-value	$a(y)$
01100	4	01101	13	169
11001	4	11000	24	576
11001	3	11011	27	729
10011	3	10001	17	289
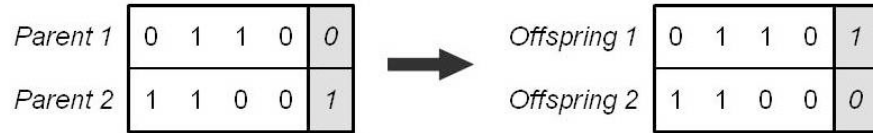
Figure 3.6. Crossover between two individuals of the mating pool at point 4. This occurs in Step 8 of the GA example.

Table 3.4
Step 10 of a GA, for a simple maximization example, with the new initial population evaluated.

Offspring population	Mutation point	Offspring population	y-value	$a(y)$
01101	10000	11101	29	841
11000	00000	11000	24	576
11011	00000	11011	27	729
10001	00100	10101	20	400

The fitness function used for the evaluation of the feeder addition problem is shown in a flowchart in Fig. 3.7. The initial population is a $\eta \times \eta+1$ matrix (η is defined below in (3.22)). Reference [66] shows that the number of generations required for convergence to the Pareto front can be reduced by carefully selecting an initial population that incorporates favorable characteristics of the system under consideration. For this reason, an initial population comprising individuals that represent each possible connection in the system, plus the individual representing no connection, was chosen. The mathematical representation of the initial population in a bit string is given as

$$Initial\ population = \begin{bmatrix} 1 & \cdots & 0 & 0 \\ \vdots & \ddots & \vdots & \vdots \\ 0 & \cdots & 1 & 0 \end{bmatrix} \tag{3.21}$$

where the individuals are in columns. The first part of the matrix in (3.21) is an $\eta \times \eta$ identity matrix, and the last column, $\eta+1$, is all zeros.

The GA procedure used in this report is part of a popular engineering and scientific software, Matlab [127]. Due to the fact that it is generic, the multi-objective optimization function has not been ideally programmed to reflect the considerations of the feeder addition problem. However, it has its own operators for mutation, crossover, and selection. Tournament selection is used to identify individuals who will survive to the next population.

An explanation of the Matlab function and why it was chosen will be given in Section 4.1 in Chapter 4. For now, it suffices to explain that the function has rigid rules on the input, and does not take the constraints as defined above. As a work-around, the constraints were moved into the evaluation of the objective function and used to penalize any topology that violates the constraints. The penalty function is a multiplier, proportional to the square of the branch overloading in (3.22) or the square of the voltage variation above or below tolerance in (3.23). Equations 3.22 and 3.23 are only evaluated for buses and branches that violate the constraints: branch loading greater than 100% and bus voltage outside of the $\pm$ 5% operating limits. The penalties, inspired by the penalty functions explained in [53], are

$$\mathbb{P}_{branch} = \prod_{k=1}^{N_{branch}} |b_{Lk}|^2 \tag{3.22}$$

where N_{branch} is the number of branch loading violations and b_{Lk} is the percentage loading on branch k. The penalties for the voltage violations are

$$\mathbb{P}_{bus} = \begin{cases} \displaystyle\prod_{k=1}^{N_{bus}} |2 - V_k|^2, & if\ V_k < 1.0 \\ \displaystyle\prod_{k=1}^{N_{bus}} |V_k|^2, & if\ V_k > 1.0 \end{cases} \tag{3.23}$$

In (3.23), N_{bus} is the number of bus voltage violations and V_k is the per unit voltage at point k. The overall penalty is given as

$$\mathbb{P} = \mathbb{P}_{bus}\,\mathbb{P}_{branch} \tag{3.24}$$

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and is applied to the ENS value. The function was chosen to penalize more heavily systems with extreme violations and to penalize more heavily those systems that have multiple violations.
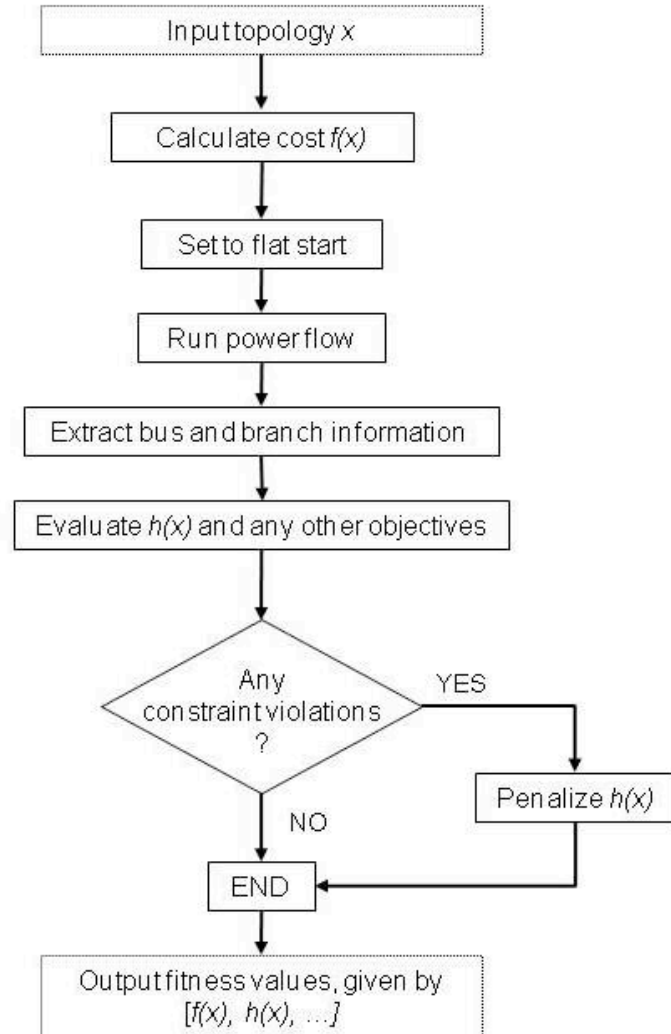
Figure 3.7. Evaluation of the objective functions. Constraints are addressed by penalizing the ENS value for topologies with constraint violations. The input topology x corresponds to an individual, or chromosome, in the overall GA flowchart.

As discussed earlier, the solution space for the feeder addition problem is non-convex and discontinuous. The objective functions do not depend linearly on the topologies; in fact, the values of the objective functions are also discrete and non-convex. Furthermore, the number of possible topologies to evaluate in a given system is very large. If the feeders are numbered as described in Table 3.5, then the number of possible connections if only one feeder is added, is given by

$$\eta = n_1\left(n_{N_B} - n_1\right) \sum_{i=1}^{N_B-2} \left(n_{N_B} - n_{i+1}\right)\left(n_{i+1} - n_i\right) \tag{3.25}$$

where N_B is the total number of buses in the system. The number of possible topologies are shown in Fig. 3.8 for both a three-feeder system and a six feeder system (see Fig. 3.9 and 3.10), both of which will be described in the next chapter. The x-axis corresponds to the number of connections made in the system, and the y-axis identifies how many different possibilities exist. The number of possible topologies is given by Equation 3.26, which uses the η defined in (3.25),

$$\mathcal{N} = \prod_j^R \eta - j + 1 \tag{3.26}$$

where R is the desired number of connections. As the number of possible topologies increases, it is less likely that the heuristic approach will find the solutions on the Pareto front. Instead, an algorithm that moves through the whole solution space in a guided manner with a provision to avoid local minima would be more likely to find points on the Pareto front. For that reason, the GA is a desired technique.

The GA can effectively make use of the non-linearity and non-convexity of the solution space using the bit-string representation of individuals. Furthermore, it deals with the number of

Table 3.5.
Sequential bus numbering procedure for M feeders.

Feeder	Buses
1	$1, 2, ..., n_1 - 1, n_1$
2	$n_1+1, n_1+2 ... n_2 - 1, n_2$
3	$n_2+1 , n_2+2 ... n_3 - 1, n_3$
...	...
$M - 1$	$n_{M-2}+1 , n_{M-2}+2 ... n_{M-1} - 1, n_{M-1}$
M	$n_{M-1}+1 , n_{M-1}+2 ... n_M - 1, n_M$

possible connections by moving through the solution space, guided by the ability of certain individuals that have adequate fitness. In the fact that connections with greater benefit will be made, this procedure is similar to the sequential feeder approach. However, unlike the sequential feeder approach, where the change is permanently made in the topology, the mutation operator works to avoid local minima, which is the best outcome that can be guaranteed by the sequential feeder approach. With enough generations, the GA has been shown to approximate the Pareto front fairly well in power system optimizations [70, 128].

This chapter discussed the general distribution system model and mathematical formulation of the feeder addition problem. The mathematical bases for the use of a heuristic algorithm and GA were also described. The next chapter, Chapter 4, will discuss the application of the models and methods developed in this chapter to two test systems, as well as the software tools utilized.
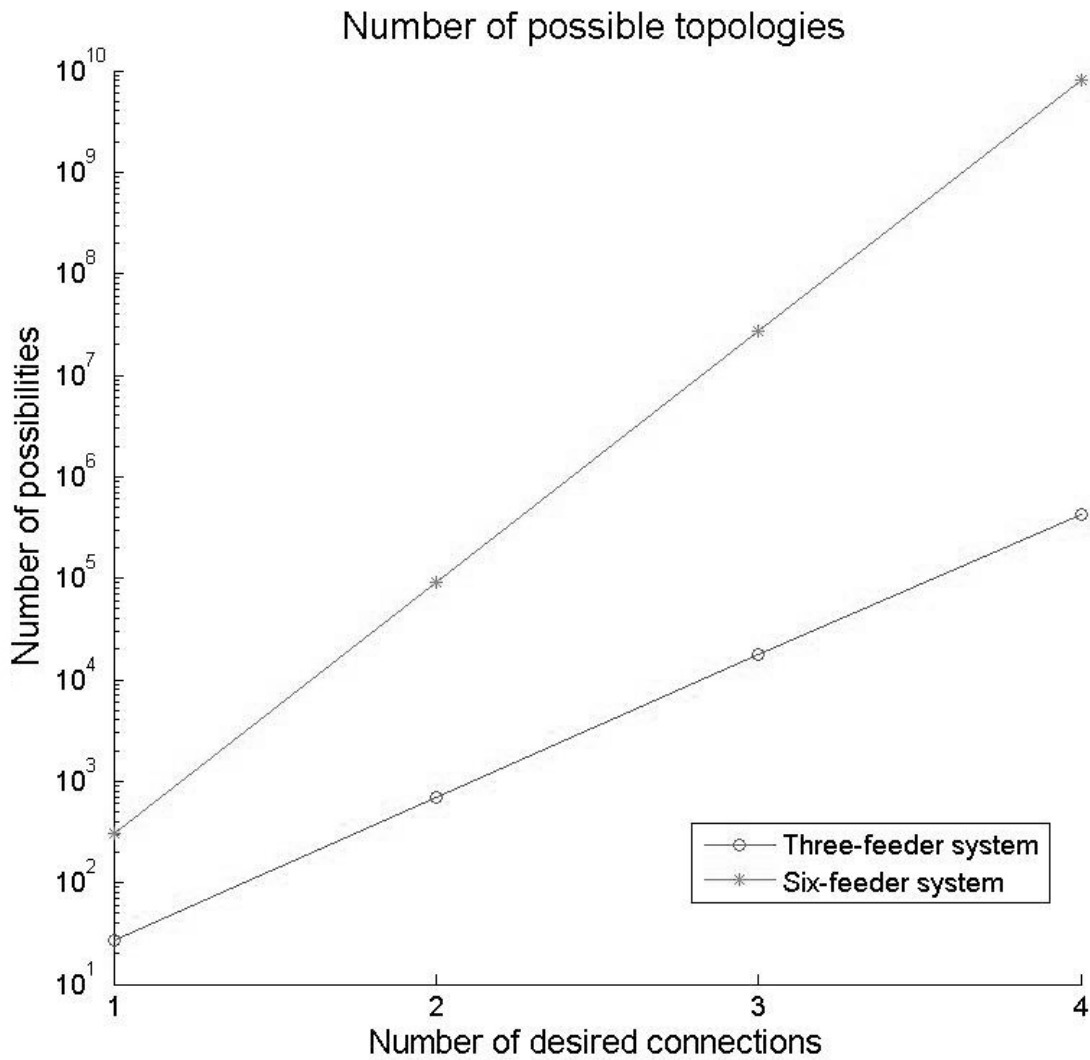
Figure 3.8. Number of possible topologies for a 9-bus three-feeder and six-feeder test system. The six-feeder system has 27 buses where connections are allowed. The x-axis shows the desired number of connections, the y-axis shows the number of possible connections on a logarithmic scale.
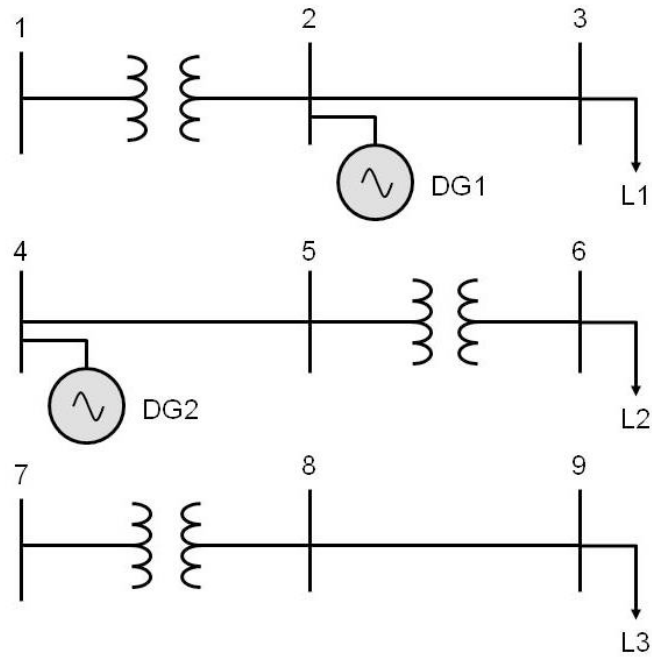
Figure 3.9. The basic topology of the 9-bus three feeder system with 2 DGs and 3 loads.
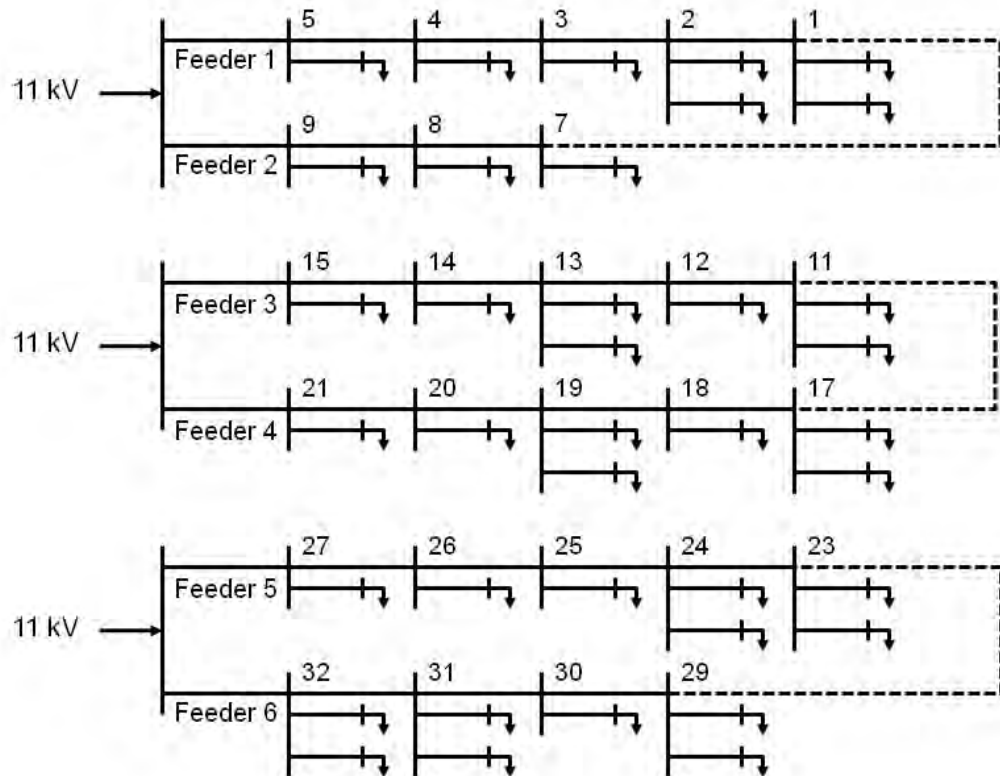
Figure 3.10. The basic topology of the RBTS test system, a 27-bus, six feeder test system, which will be described in more detail in Chapter 4.

CHAPTER 4

CASE STUDIES OF THE FEEDER ADDITION PROBLEM

This chapter will discuss the software tools necessary to complete the optimization of the feeder addition problem. The optimization of the feeder addition problem was solved for two different test systems, using two different methods for each system, namely the sequential feeder approach and a multi-objective GA. The mathematical formulations of these methods were described in Chapter 3. The feeder addition problem is to add networked connections in a given distribution system with DGs such that the cost of the addition is feasible while improving the reliability and satisfying power flow constraints. Furthermore, results from the application of the optimization to two different test systems will be described and discussed.

4.1 Software tools

To complete the optimization for the feeder addition problem, several software tools were necessary. There are three major parts to the problem itself: the optimization, the power flow, and the reliability analysis. The reliability was calculated based on the power flow, leaving the optimization and the power flow as the major numerical tasks. The optimization was completed using the sequential feeder method, which was programmed in Matlab R2008a. The power flow was solved using the Automation Server (SimAuto) add-on for PowerWorld Simulator 14.

4.1.1 *Matlab*

Matlab was chosen for the programming required in this report due to its powerful programming environment and many built-in functions. The Matlab codes used for the simulations in this chapter are given in Appendices 2 and 3, which describe the sequential feeder methods and the multi-objective GA, respectively. Sub-functions were extensively used to simplify the main code for a given test system.

The Matlab sub-function to run a multi-objective GA for a user-defined fitness function is *gamultiobj()*. This sub-function uses a controlled elitist algorithm, which is a variant of the NSGA-II [129]. The Pareto fraction controls the amount of elitism in the algorithm by limiting the number of individuals that are allowed to be on the Pareto front [129]. Elitism is often used to increase the performance of a GA by copying the best individuals of a generation to the next generation without crossover or mutation [126]. The function can accept 'bitString' formatted population types, but in practice a rounding function had to be added to the fitness function for the feeder addition problem

because the algorithm generated fractional values for individual chromosomes. Individuals are selected for reproduction based on tournament selection, which randomly selects individuals who then "compete" [126]. The individual with the best fitness value wins and is added to the mating pool and the mating pool is filled via repeated application of the tournament [126]. The function uses scattered crossover, which identifies multiple crossover points using a binary vector.

The shortcomings of the GA function include the fact that only one individual of a population may be passed to the fitness function each time it is evaluated. The inability to pass multiple variables to the fitness function adds to the run time. The main component of additional time due to the inability to pass variables is that each time the fitness function is evaluated, the connection to SimAuto must be established and the system file opened. To establish the connection and open the system file takes approximately 10 s. For a population with many individuals this contributes a large part to longer run times. For example, if there are 100 individuals in a population, the inability to pass variables to the fitness function adds 1000 s (or 16.66 minutes) every generation.

4.1.2   *PowerWorld and SimAuto*

Although Matlab had many built-in functions, it did not have a function to solve a power flow for a transmission or distribution system. The use of several free power flow software packages that could be used in Matlab was explored, such as MATPOWER [130] and PSAT [131]. Additionally, SimPowerSystems for Matlab Simulink was explored [132]. Each different software was tested for a set of simple radial feeders with multiple slack buses. It was found that many had difficulty converging with more than one slack bus in the system. The optimization of the feeder addition problem required the evaluation of a power flow on radial systems as the base case. Finally, PowerWorld Simulator 14 was chosen, with an add-on called SimAuto which allowed one to remotely access PowerWorld from Matlab [133, 134].

The use of PowerWorld had the additional benefit that test systems could be built graphically with the relevant component data. The typical procedure included building the test system in the PowerWorld environment, then entering the Matlab environment and using SimAuto to run power flows, extract test system information, and change topological structures, if necessary. SimAuto contains most of the functionality available in PowerWorld through the use of script commands and *.aux* files. Typical functions include adding a component, solving the power flow, setting the system to flat start, changing the system mode (run or edit), and changing the values of existing components.

The code included in the electronic appendix for Volume IA for Volume IA, described in Appendix II, makes use of custom Matlab subfunctions that were created to reduce the overall lines of code. Some of these functions include *editmode()*, which changes the system mode to 'edit', *runmode()*,

which enters the system mode 'run', *flatstart()*, which resets all bus voltages to 1 p.u. at an angle of zero, and *resetslack()*, which resets the slack bus outputs to zero. The type of power flow used for this work was Polar-Newton, which is the Newton-Raphson power flow as described in [133]. The next section describes the results of the case study on a simplified test system using the software tools previously described.

4.2 Simplified three-feeder test system

The simplified three-feeder test system (3FDR) was developed to test the sequential feeder method and the GA. The system incorporates three feeders, three transformers, three loads, and two RE DG sources, one is solar-based and the other is wind-based. The purpose of using a simple test system was to ensure the successful implementation of the software tools and optimization techniques. System data and results using the sequential feeder method were presented in [125] © 2010 IEEE.

4.2.1 *3FDR test system data*

The 3FDR topology is shown in Fig. 4.1. 3FDR has three feeders, ten buses, and two voltage levels, V_1 and V_2, where V_1 is greater than V_2. There are three loads, at buses *3, 6,* and *9*, and two RE DG sources at buses *2* (a PV array) and *4* (a wind turbine). Buses *1*, *4*, and *7* are normally connected to the grid. Since the modeling of this system is under isolated conditions, the grid ties are not shown. Some of the system data for the 3FDR test system were synthesized using example data from [4]. For the purpose of this example, it is assumed that the RE DG sources are modeled using the wind and solar capacity factors, 0.25 and 0.30 respectively, as discussed in Chapter 3, excluding the terms for CDG sources and DS. It is also assumed that the required loads on Feeders 1 and 2 are rated less than the RE DGs located on those feeders. Each load bus has a non-critical and a critical load component. The critical load is the load that must be served and cannot be interrupted. Table 4.1 describes the power requirements of the system loads and the power outputs of the RE DG sources, which are split into the rated power and the power that was assumed for the solution of the feeder addition problem. Table 4.2 gives the line data for existing connections and Table 4.3 provides the data used for the possible connections between feeders. In the event that a transformer was required for the connection, an impedance of *0.01 + j0.06* on the transformer base was assumed and the branch was collapsed to its equivalent circuit. The costs given in Table 4.3 were generated using the cost assumptions shown in Table 4.4.

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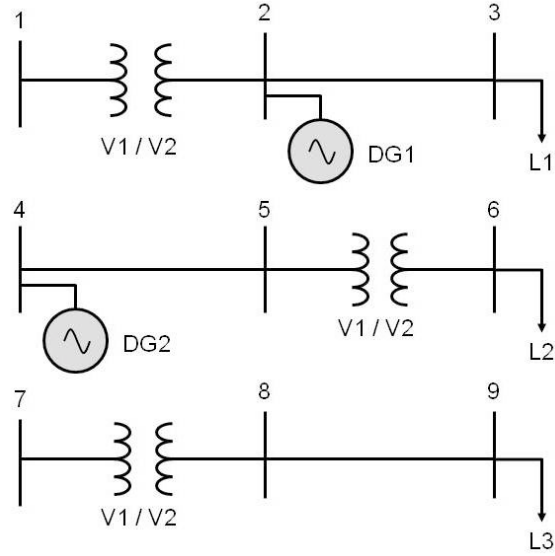
Figure 4.1. 3FDR with 10 buses, 3 feeders, 3 loads, and 2 RE DG sources. V_1 is 12.47 kV and V_2 is 2.4 kV. Buses *1*, *4*, and *7* are normally grid-connected. Reproduced from [125] © 2010 IEEE.

Table 4.1

System loads and generation in 3FDR test system. Reproduced from [125] © 2010 IEEE.

Load	Non-critical P (kW)	Critical P (kW)
L1	712.5	80.2
L2	617.5	100.2
L3	264.8	50.8
Generator	Rated P (kW)	Modeled P (kW)
DG1	297	89.1
DG2	568.4	142.1

Table 4.2

Branch data for existing connections, presented on a base of 2 MVA and 12.47 kV on the high side for the lines and the individual transformer bases for the transformers. Reproduced from [125] © 2010 IEEE.

Connection	Length (mi.)	R (p.u.)	X (p.u.)
Line 2-3	0.2841	0.0066	0.0175
Line 4-5	0.3314	0.0002	0.0006
Line 8-9	0.4213	0.0059	0.0153
Transformer 1-2	N/A	0.0100	0.0600
Transformer 5-6	N/A	0.0100	0.0600
Transformer 7-8	N/A	0.0100	0.0600

Table 4.3

Branch data for possible connections, presented on a base of 2 MVA and 12.47 kV on the high voltage area. The cost was determined using the synthetic data in Table 4.4. Reproduced from [125] © 2010 IEEE.

Connection	Length (mi.)	R (p.u.)	X (p.u.)	Cost (x 10^3 $)
Line 1-4	0.1894	0.0001	0.0093	200.00
Line 1-5	0.3788	0.0002	0.0186	300.01
Line 1-6	1.1364	0.0159	0.0420	800.01
Line 1-7	0.3206	0.0042	0.0558	269.28
Line 1-8	0.3909	0.0055	0.0144	603.19
Line 1-9	0.5666	0.0079	0.0209	649.57
Line 2-4	0.4261	0.0060	0.0257	612.49
Line 2-5	0.2841	0.0040	0.0105	575.00
Line 2-6	0.3267	0.0046	0.0121	186.25
Line 2-7	0.3262	0.0046	0.0120	586.11
Line 2-8	0.3551	0.0050	0.0131	193.75
Line 2-9	0.5926	0.0083	0.0219	256.45
Line 3-4	0.8996	0.0126	0.0332	737.49
Line 3-5	0.7576	0.0106	0.0280	700.01
Line 3-6	0.4214	0.0059	0.0156	211.25
Line 3-7	1.0432	0.0146	0.0386	775.41
Line 3-8	0.9996	0.0140	0.0369	363.90
Line 3-9	1.4330	0.0200	0.0529	478.31
Line 4-7	0.1376	0.0001	0.0003	172.65
Line 4-8	0.1701	0.0024	0.0063	544.91
Line 4-9	0.4543	0.0064	0.0168	619.95
Line 5-7	0.3588	0.0002	0.0007	289.46
Line 5-8	0.3933	0.0055	0.0145	603.84
Line 5-9	0.5764	0.0081	0.0213	654.16
Line 6-7	0.5687	0.0080	0.0210	650.14
Line 6-8	0.4136	0.0058	0.0153	209.19
Line 6-9	0.3855	0.0054	0.0142	201.77

Table 4.4

Cost of system additions to 3FDR. Reproduced from [125] © 2010 IEEE.

Device	Cost
Transformer	$400000
2.4 kV Line	50 $/ft
12.47 kV Line	100 $/ft
Fixed Line Cost	$100000

The 3FDR system topology may be represented by a sparse adjacency matrix or incidence matrix describing the connectivity between buses. The binary bus connection matrix B was defined in [125] © 2010 IEEE and explained in Chapter 3. For the ease of reference, the definition is reproduced in (4.1).

$$[B]_{ij} = \begin{cases} 1 \; if \; bus \; i \; is \; connected \; to \; bus \; j \\ \quad 1 \; if \; i = j \\ \quad 0 \; otherwise \end{cases} \quad (4.1)$$

Any zero entry in B is a possible candidate for a new connection for the feeder addition problem, which requires that connections be made between existing feeders. Such a requirement allows the partitioning of the B matrix into an array of allowed new connections. Fig. 4.2 shows the 'partitioned' B matrix and its subset of allowed connections shown with shaded background. The B matrix is symmetric. However, the 'partitioning' in the lower left triangle of Fig. 4.2 is not shaded for simplicity.

Bus	1	2	3	4	5	6	7	8	9	10
1	1	1	0	0	1	0	0	1	0	0
2	0	1	1	0	0	0	0	0	0	0
3	0	1	1	1	0	0	0	0	0	0
4	0	0	1	1	0	0	0	0	0	0
5	1	0	0	0	1	1	0	0	0	0
6	0	0	0	0	1	1	1	0	0	0
7	0	0	0	0	0	1	1	0	0	0
8	1	0	0	0	0	0	0	1	1	0
9	0	0	0	0	0	0	0	1	1	1
10	0	0	0	0	0	0	0	0	1	1

Figure 4.2. The binary bus connection matrix, B, for 3FDR. The possible connections are in the shaded area of the matrix. Reproduced from [125] © 2010 IEEE.

The 3FDR test system was built in PowerWorld using the data provided. The possible connections were implemented as open lines. The line capacities and transformer capacities were oversized. In the next two sections, the results of the optimization of the feeder addition problem applied to the 3FDR will be provided. The feeder addition problem aims to add connections between feeders to improve the reliability of the system at an optimal cost. The two main objectives to minimize are cost and ENS, which is a reliability measure. A few simulations considered the additional minimization of a third objective – losses. The results of the three objective simulations will be explained in Section 4.2.4, 'Three objective optimization on the 3FDR'.

4.2.2 *Results of the sequential feeder method for the 3FDR test system*

Following the sequential feeder approach, possible new connections between feeders in the 3FDR test system were added, so that the load served at Bus *9* was maximized. The initial ENS was 278.1 kWh. This was determined by assuming that the system had an ASAI of 0.999375 corresponding to outages totaling 5.475 hours per year [78]. The solution space of the first two connections is shown in Fig. 4.3. For the first connection considered, the sequential feeder method explores each possible connection, which are plotted as '*' on Fig. 4.3. The connection with the greatest increase in reliability was chosen. If more than one connection had the same reliability to within a tolerance of 1×10^{-4} MWh, the least cost solution was chosen to be added to the system, which was then made permanent for the second connection. It was found that the ENS could be decreased to 48.7 kWh if a lateral was added between feeders 2 and 3. The proposed connection was between buses *4* and *7* at a cost of $0.173 million. This connection was made permanent in the system topology and is shown in Fig. 2.3 at the 'o' with zero cost and 0.487 MWh.

The possibilities for the second connection are shown in Fig. 4.3 as 'o'. The next greatest reduction in ENS was achieved by the addition of a lateral between feeders 1 and 2, which reduced the unserved energy to zero by adding a lateral between buses *4* and *7* at a cost of $0.186 million. The resulting topology calls for the addition of a lateral between buses *2* and *6*, and the addition of a lateral between buses *4* and *7*. The total cost of these topology additions is $358,900 (based on synthetic data already provided in Table 4.4). The result of the heuristic technique is given in Fig. 4.4 and the topology is the cheapest option to produce the optimum reliability.

4.2.3 *Results of the multi-objective GA for the 3FDR test system*

The application of a multi-objective GA to the 3FDR test system was accomplished using Matlab and PowerWorld SimAuto. The initial population was assumed to be a sparse matrix of the different possible connections – one connection per individual – in addition to an individual that described the base case. The number of generations was used as the stop criterion, which stops the simulation if more than a certain number of generations have passed. A generation includes evaluation of the current population, reproduction, crossover, and mutation, as described in detail in Chapter 3. Several trials were completed to ensure that the results were accurate.

The Pareto front shown in Fig. 4.5 was achieved for a run with 10 generations. Increasing the number of generations did not affect the ultimate output. This is most likely related to the sparsity of the vectors; increasing the crossover and reproduction that the population undergoes
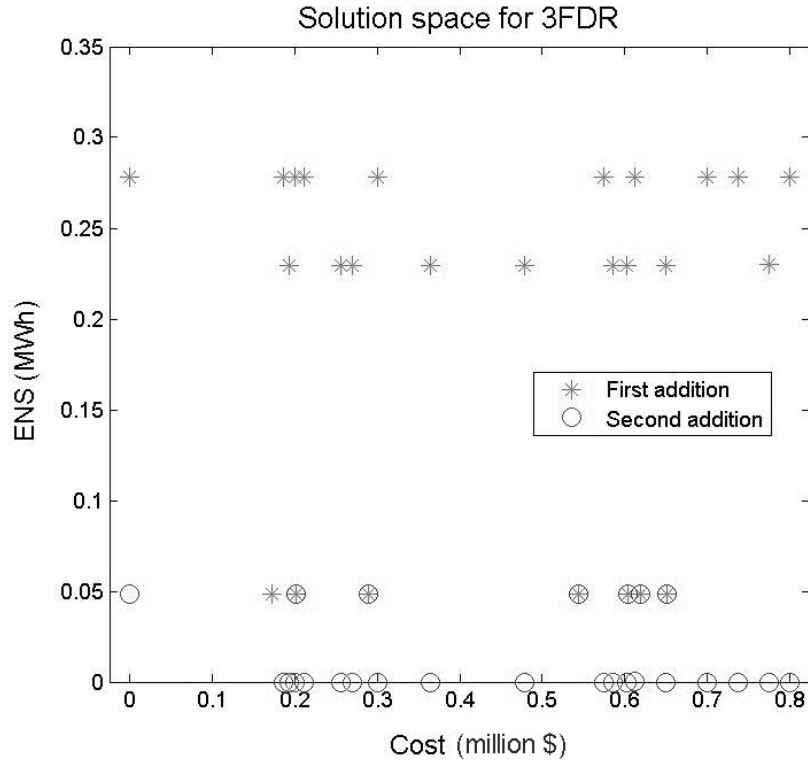
Figure 4.3. Solution space for the sequential feeder method applied to the 3FDR test system. The first connection was chosen based on least cost and then the second connection was explored.
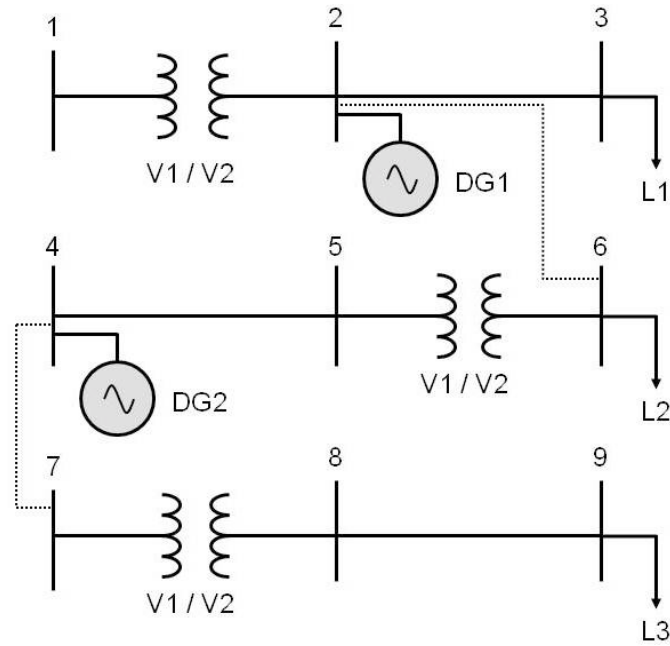
Figure 4.4. Results of the sequential feeder approach applied to the 3FDR test system. The proposed lines are shown as dashed. © 2010 IEEE.

will primarily serve to make the vectors less sparse. The cost of the system changes is related to the sparsity of the vectors, the fewer 1's in the vector, the lower the cost, in general. As more crossover and mutation happens, the number of 1's increases, thereby making the cost objective less optimal, broadly speaking. The points shown in the Pareto front of Fig. 4.5 correspond to the information in Table 4.5. It is seen that the results achieved with the GA match those from the sequential feeder method. It took 3078 s (approximately 51 min) to evaluate 10 generations of the multi-objective GA on a non-devoted Intel® Core^{TM} 2 Duo CPU at 2.80 GHz.
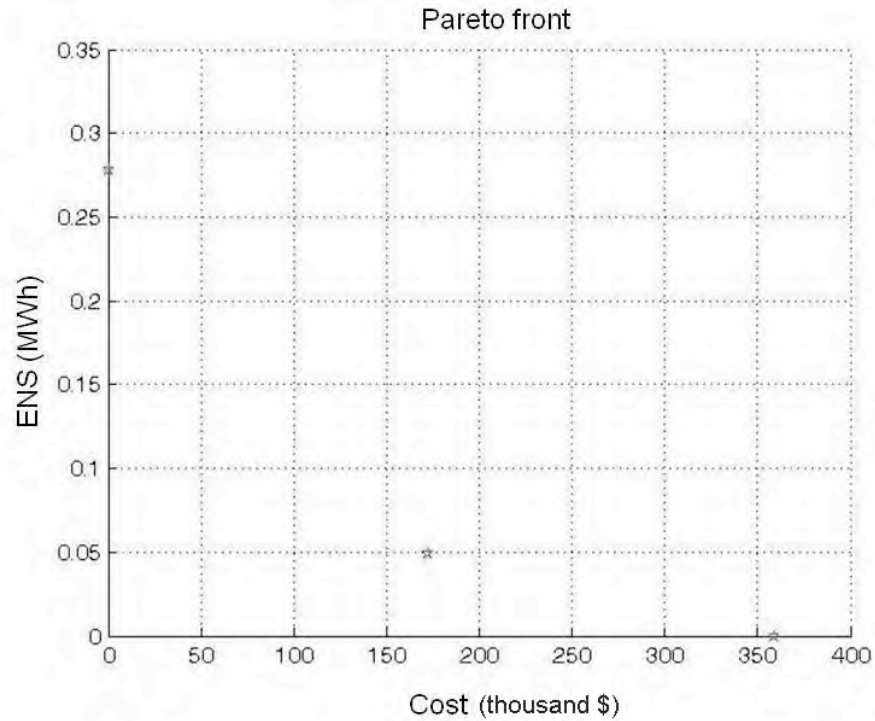
Figure 4.5. Output of 10 generations of the GA applied to the 3FDR test system. The results agree with those found using the sequential feeder approach. The run time was 51 min.

4.2.4   *Three objective optimization on the 3FDR*

To further explore the uses of the optimization approaches described in this report, several trial runs incorporating losses for the 3FDR were completed using both the sequential feeder approach and the multi-objective GA. The sequential feeder approach used the lexicographic ordering with loss considered last so that the results were not different from those for the cost and ENS optimization. During the simulations, it was found that the total amount of losses was not correlated strongly to the cost and reliability, or ENS. For example, a low-reliability solution is no more or less likely to have high or low losses than a high reliability solution. Furthermore, the magnitude of the differences in losses between the best case and the worst case was 60 W from the sequential feeder approach and 70 W from the GA

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solutions. This magnitude is small compared to the ratings of the DGs and the loads, which are on the order of 50-100 kW. The solution spaces for the three objectives are shown in Fig. 4.6-8, where Fig. 4.6 shows the cost versus ENS, Fig. 4.7 shows the cost versus losses, and Fig. 4.8 shows the ENS versus losses. The three given plots were generated from the sequential feeder approach.

The triple objectives were also optimized using the multi-objective GA. To achieve an accurate Pareto front, several trials using different numbers of generations for the stop criteria were completed. The results are shown in Figs. 4.9-11, which show cost and ENS, cost and losses, and ENS and losses, respectively. Each of the plots shows the outcomes of increasing numbers of generations: 10 generations, 50 generations, 100 generations, and 150 generations.

In Figs. 4.9-11, the Pareto front is denoted by points. The size of the marker increases as the number of generations increases. As a result, a point with a bulls-eye pattern around it would have been a part of the Pareto fronts for several of the simulations with different generation numbers. Moving from the lowest cost solution in Fig. 4.9, it is seen that the first two Pareto optimal points are found by all simulations. The next Pareto optimal point is found by all except the 10 generation simulation. These three points described are the points found to balance the cost and ENS in simulations limited to those two objectives.
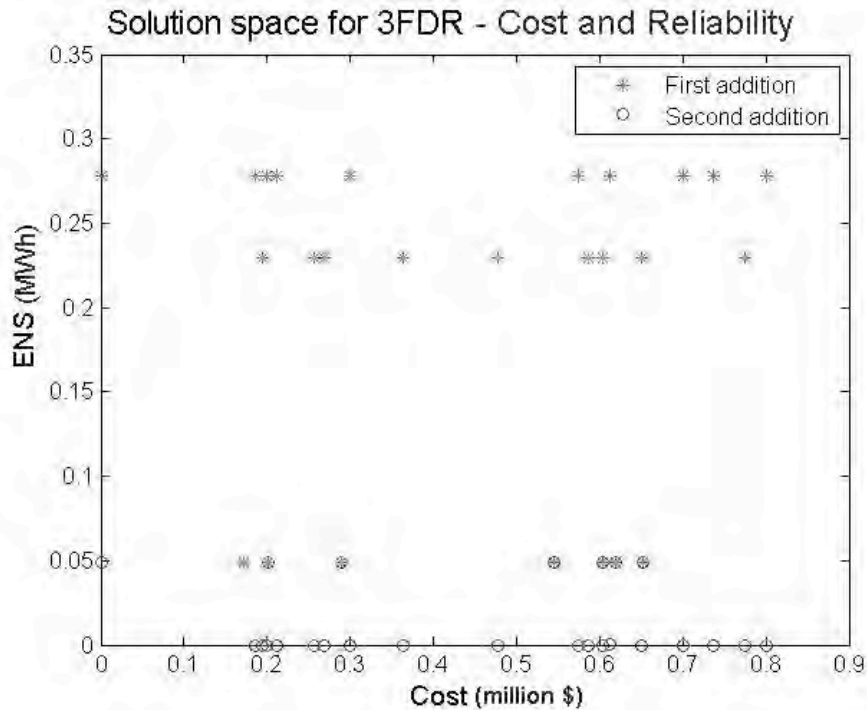
Figure 4.6. Cost and ENS objectives for the triple-objective sequential feeder approach.

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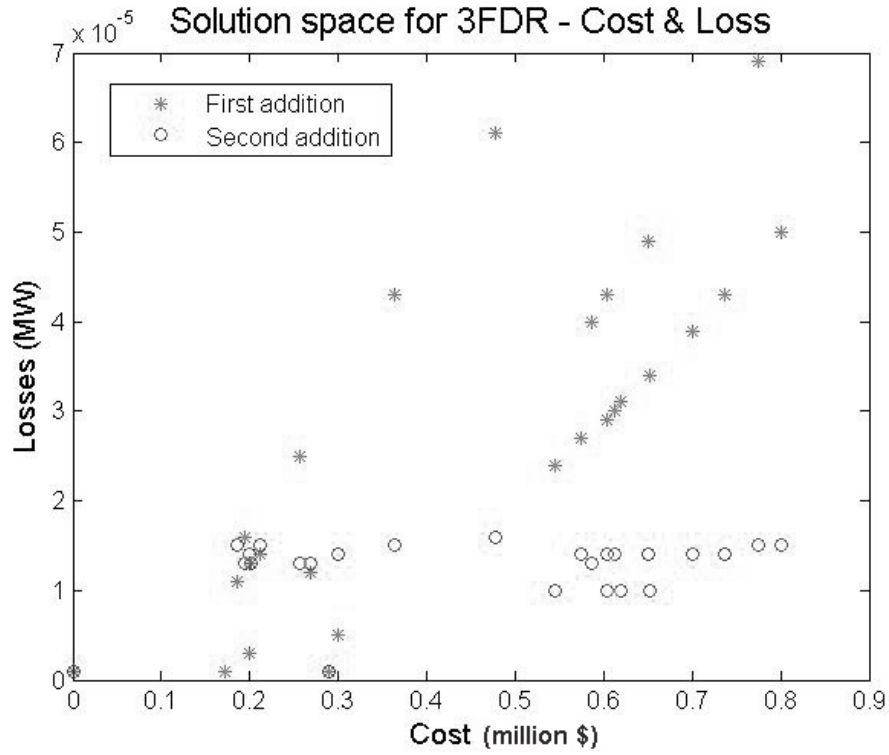
Figure 4.7. Cost and loss objectives for the triple-objective sequential feeder approach.
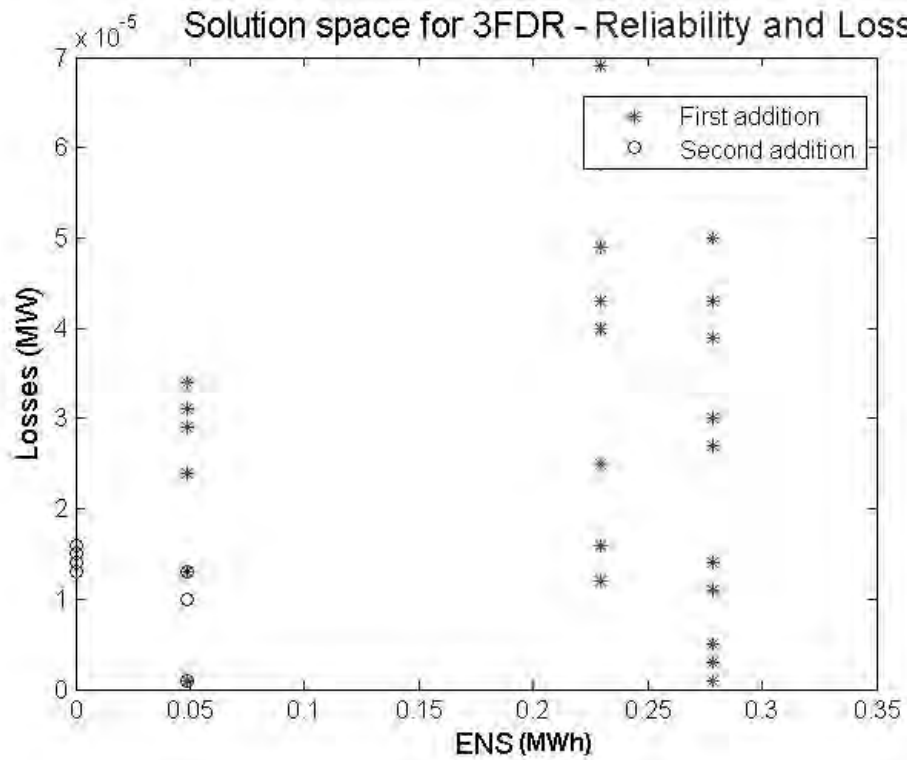
Figure 4.8. ENS and loss objectives for the triple-objective sequential feeder approach.

As expected, the simulation time increased with more numbers of generations. The run times are shown in Fig. 4.12, which shows the time in hours compared to the number of generations. There are several reasons for the long run times, which include the programming of the fitness function and the population size. The following is a detailed discussion of the general concerns with GA procedure discussed in Section 4.1.1. The manner in which the multi-objective GA processes individuals requires that the fitness function be evaluated for each individual of a population and that the only input is that individual. As a result, a new connection to SimAuto must be made every time that the fitness function is evaluated, which must happen for every individual in a population each generation. Establishing the connection to SimAuto can take as many as 5 s using a non-devoted Intel® Core™ 2 Duo CPU at 2.80 GHz, which quickly propagates into long run times, when combined with the number of individuals in a population.
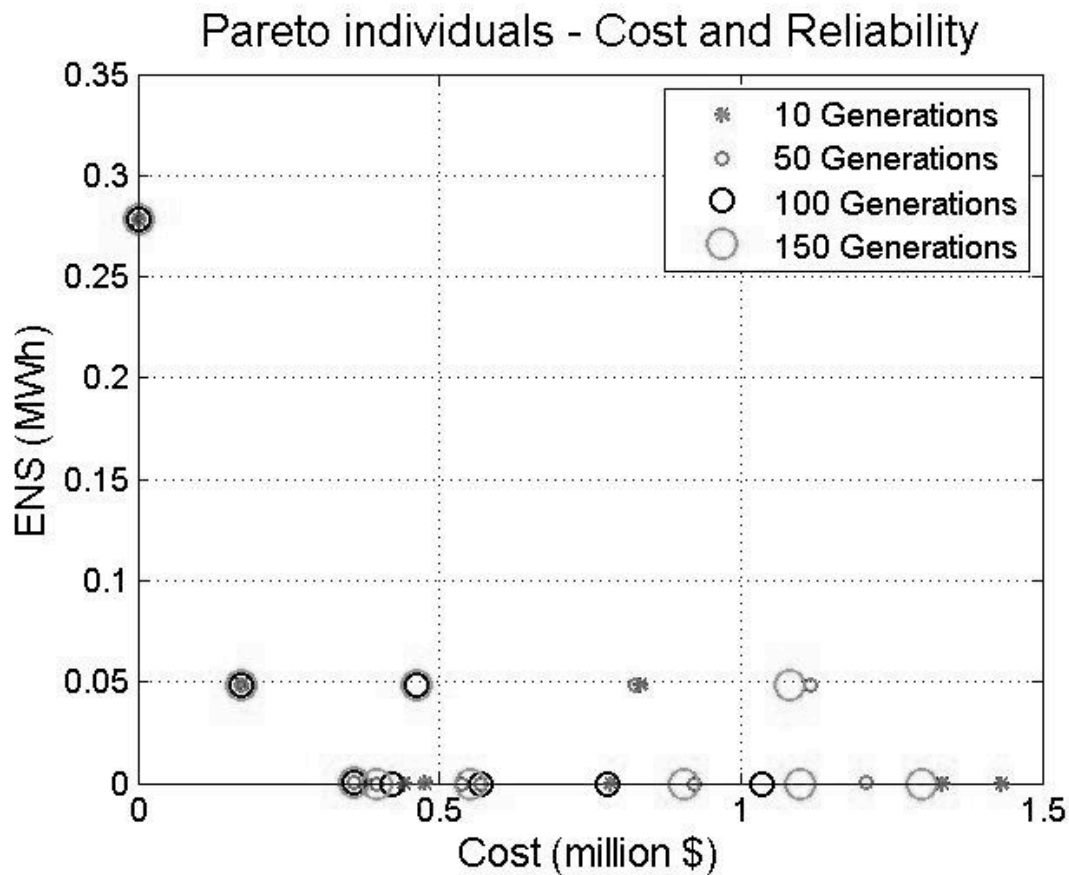
Figure 4.9. Cost and ENS fitness values for the Pareto individuals found using a triple-objective GA. The cost is given in 'per unit', divided by 10^6.
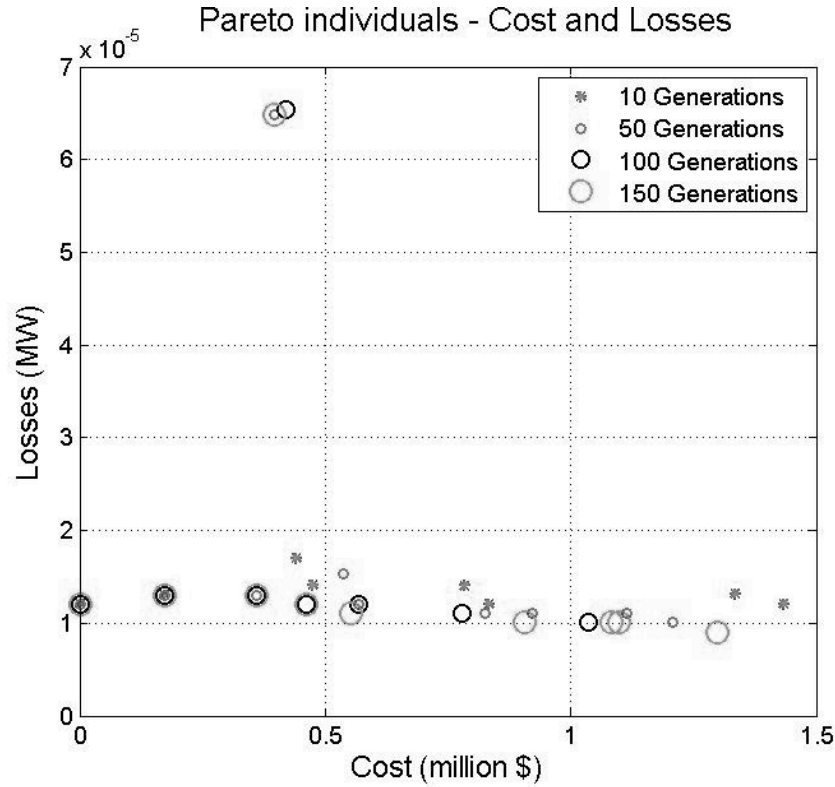
Figure 4.10. Cost and loss objectives for the Pareto individuals found using a triple-objective GA. The cost is given in 'per unit', divided by 10^6.

4.2.5 *Discussion of the 3FDR test system*

Although the outputs of the sequential feeder method and the multi-objective GA agreed for the 3FDR test system, it is not expected that this will happen for a more complex system. The added complexity limits the ability of the sequential feeder approach to find optimality in a heuristic way. The stochastic search of the GA is less likely to get "caught" in local minima. This effect will be shown for a more complex system in Section 4.3. The GA for the 3FDR test system appeared to converge in 10 generations for two objectives. In other words, the same Pareto front was achieved for increasing numbers of generations, due to the sparse nature of the individuals and the population size.

The case studies exploring the minimization of three objectives, cost, reliability, and losses, showed that those three objectives are not easily optimized when one of the objectives is not easily affected by another. In other words, because the system losses on the 3FDR were low to begin with, it is difficult to find an optimal solution for further reducing the losses at the expense of reliability or cost of addition.
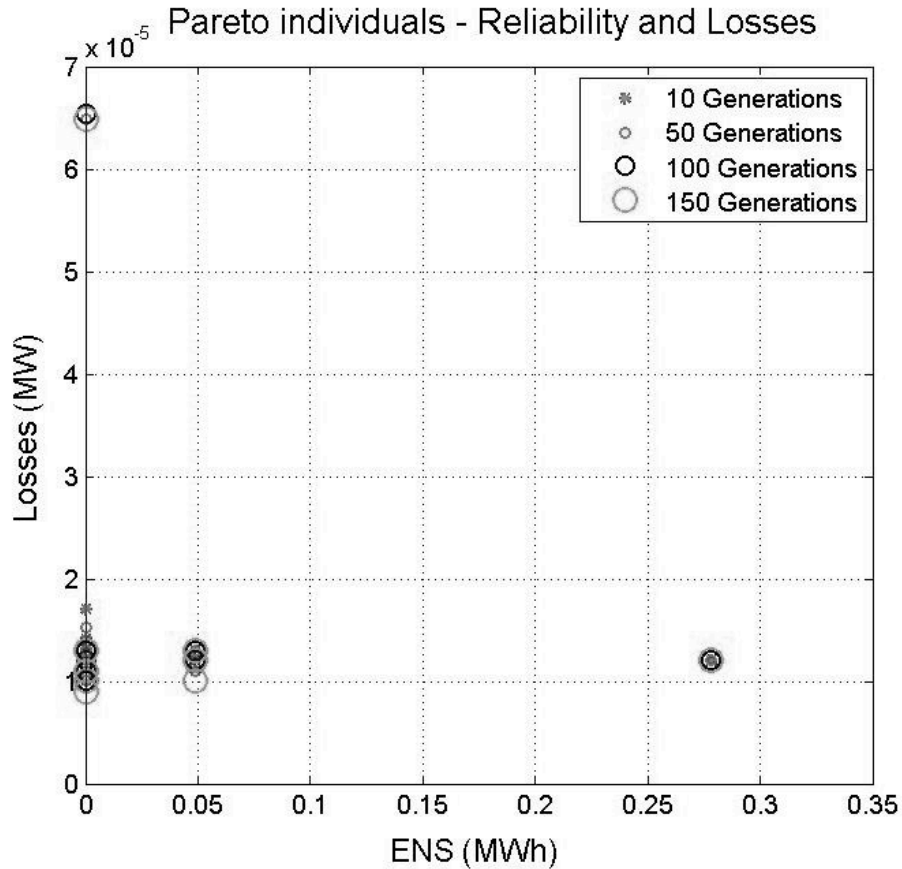
Figure 4.11. ENS and loss objectives for the Pareto individuals found using a triple-objective GA.
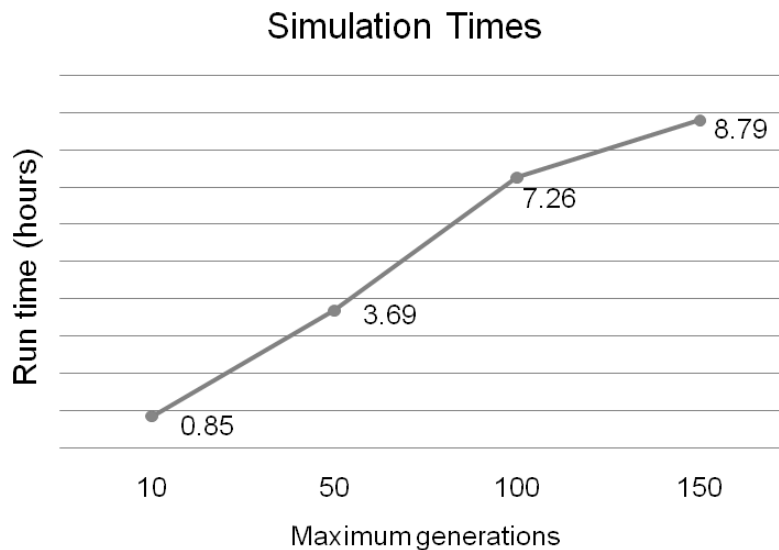
Figure 4.12. Run times for the triple-objective GA using the generation number as the stop criterion. The 150 generation run stopped because the average change in the spread of Pareto solutions was less than the tolerance of 1×10^{-4}, which overrode the maximum number of generations. The processor was a non-devoted Intel® Core[TM] 2 Duo CPU at 2.80 GHz.

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4.3 Roy Billinton Test System

The Roy Billinton Test System (RBTS) was developed by the Power Systems Research Group at the University of Saskatchewan as a tool for reliability education [135]. The test data for the transmission system is given in [135], and is extended to the distribution-level in [136]. In this report, four test cases with differing arrangements of DGs in the RBTS are explored. The feeder addition problem is solved for the first three test cases using the sequential feeder method and the multi-objective GA and the results are given. The fourth test case offers a perspective into the applicability of the optimization. A comparison of the sequential feeder method and the GA is included in Section 4.3.4.

4.3.1 *RBTS data*

The general RBTS transmission system, shown in Fig. 4.13, is reproduced from [135]. The 11 kV distribution circuits off of Bus 3 were chosen as the candidate system. The 11 kV distribution circuits comprise a part of the 85 MW peak load of Bus 3 because two 138 kV feeders were neglected. The Bus 3 distribution circuit, shown in Fig. 4.14, has six feeders and 26 buses, excluding six slack buses used for modeling; the system was reproduced from [136]. The different DG locations at buses *23*, *8*, *2*, and *14* are denoted by generators A-D. The DG locations were selected randomly. Table 4.5 gives the load point details, as originally provided by [136]. Under emergency conditions, 20% of the total load of the Bus 3 distribution system is curtailable [135]. However, since it is unclear which specific buses in the distribution system would be able to cut their load, the 20% decrease is taken into account when the ENS is calculated, instead of in the system model. In the ENS calculation, the slack bus output is multiplied by 0.80 to correspond to the fact that only 80% of the unsupplied load must be supplied. The line data from [136] are given in Table 4.6, in addition to the transformers that were chosen for system modeling. The transformers were assumed to be 11 kV/480 V, with a per unit impedance of *j0.06* on a base of 1 MW. To evaluate the effectiveness of the optimization methods for different arrangements of DGs, the DG positions shown in Fig. 4.14 were chosen randomly. Then, four case studies were developed with differing outputs for each DG. The DG outputs for each case study are shown in Table 4.7, based on the DG output equation (3.6) given in Chapter 3. The capacity factor of solar resources was assumed to be 0.30 and the capacity factor of wind resources was assumed to be 0.25. It is assumed that the wind resources comprise 40% of the RE resources and that the solar resources comprise 60% of the RE resources. The small difference in the total outputs of the DG for each case study is due to the different load points associated with the DGs' location. Cases I-IV offer increasing 'distribution' of the DGs, so that the outcomes of the optimization methods may be compared for different DG location characteristics.
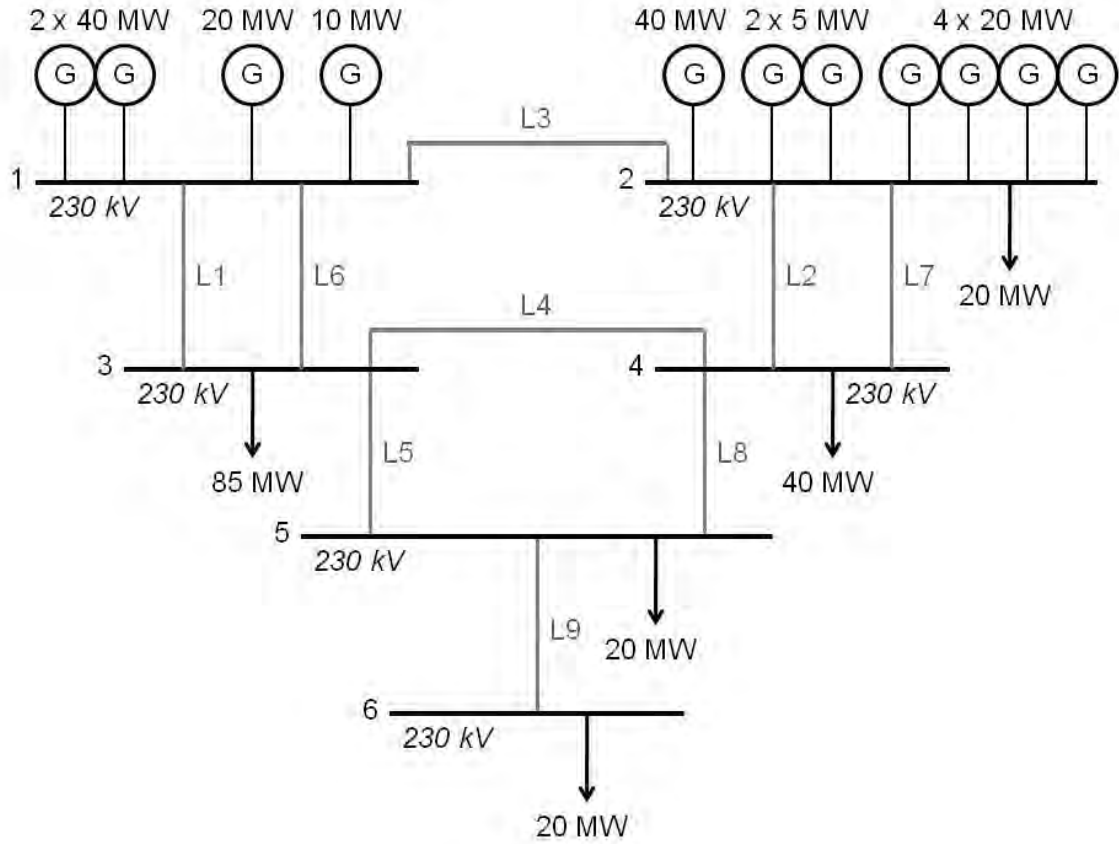
Figure 4.13. The RBTS transmission system, reproduced using [135]. The RBTS 11 kV distribution system used in this report is part of the load at Bus 3. The 85 MW load includes some 138 kV feeders and is the peak load.

The RBTS Bus 3 distribution system has 302 possible connections on just the main feeder buses (numbered buses *1-33* in Fig. 4.14). Since there was no topographical information available, a fixed distance between feeders was assumed. The distance assumption was necessary to calculate the length of the possible connections. The geometry of the calculation is shown in Fig. 4.15 for feeders 1 and 2. There are three main measurements used to determine the distance of a possible connection between feeders, ε :

- d, the distance between feeders
- ξ, the distance of the 'to' bus to the slack bus on the 'to' feeder, and
- λ, the distance of the 'from' bus to the slack bus on the 'from' feeder.

The slack buses are defined as shown in Fig. 4.14 and are specified as the low voltage side of transformers located in a switchyard. The three topographical measurements are used to calculate the lengths of the possible connections according to the following

$$\varepsilon = \begin{cases} \sqrt{d^2 + (\xi - \lambda)^2}, & \xi \neq \lambda \\ d, & \xi = \lambda \end{cases} \tag{4.2}$$

The above calculation may be required in the absence of topographical information of a test system in order to estimate the distance between buses for the possible connections. For the procedure to be applied on an actual distribution system, it is assumed that the lengths of the right-of-ways would be available to the planning engineers.
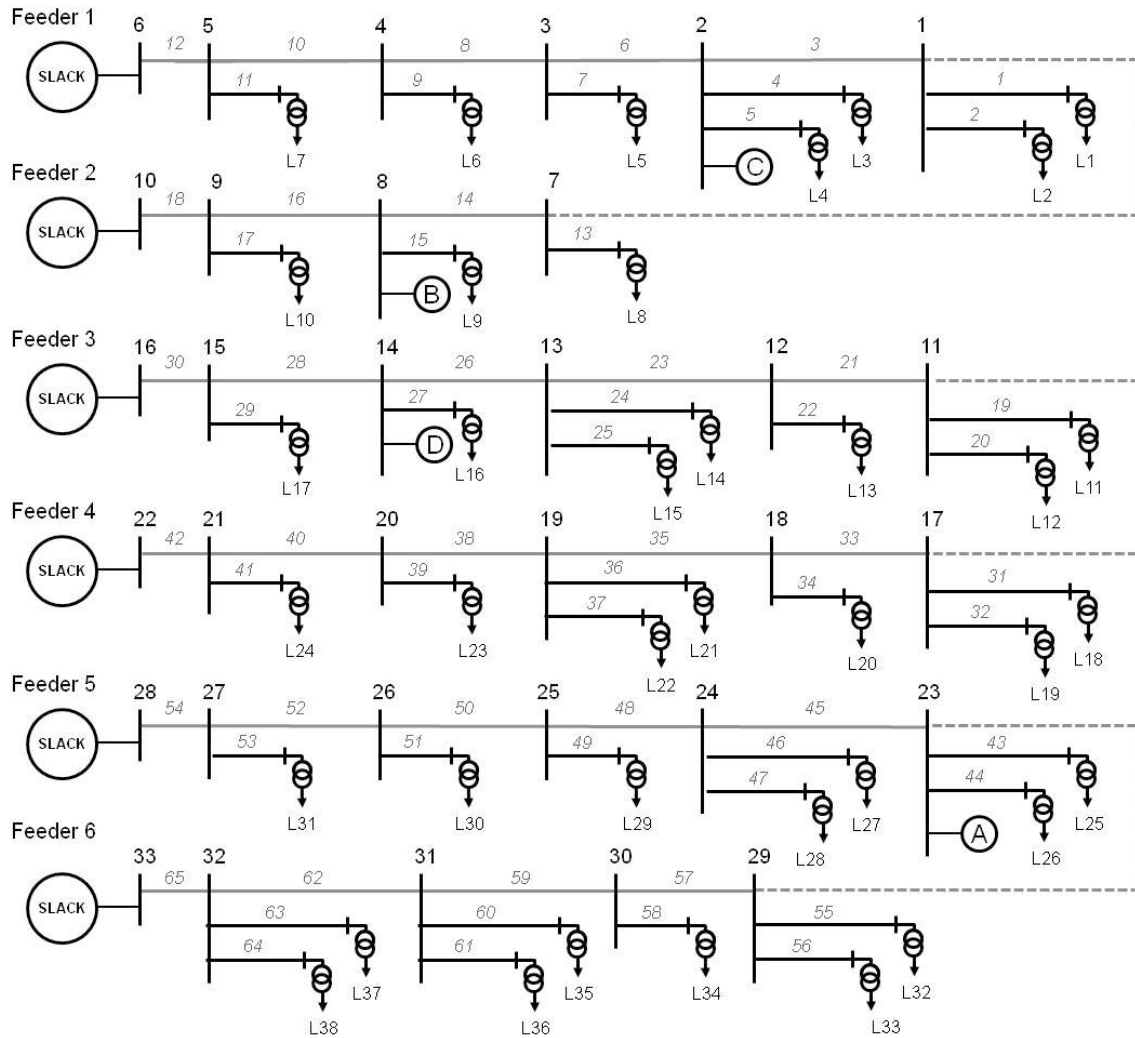
Figure 4.14. The RBTS Bus 3 distribution system, reproduced using [136]. The 138 kV feeders attached to Bus 3 are neglected as part of this application. The DGs for the case studies are located at positions A-D.

Table 4.5
Load data for the RBTS Bus 3 11 kV distribution system. Load numbers are shown in Fig 4.14. Data originally supplied in [136].

Customer type	Peak load (MW)	Average load (MW)	Number of customers	Load points
Residential	0.8367	0.4684	250	1, 4-7, 20-24, 32-36
Residential	0.8500	0.4758	230	11, 12, 13, 18, 25
Residential	0.7750	0.4339	190	2, 15, 26, 30
Small industrial	1.0167	0.8472	1	8, 9, 10
Commercial	0.5222	0.2886	15	3, 16, 17, 19, 28, 29, 31, 37, 38
Office buildings	0.9250	0.5680	1	14, 27

Table 4.6
Branch data for the RBTS Bus 3 11 kV distribution system. Line section numbers are shown in Fig 4.14. Transformers are given by the load point that is served. Line data originally supplied in [136]; transformer data assumed by the author.

Line type	Length (km)	Line section numbers
1	0.6	1, 2, 3, 7, 11, 12, 15, 21, 22, 29, 30, 31, 36, 40, 42, 43, 48, 49, 50, 56, 58, 31, 34, 67, 70, 71, 76
2	0.8	4, 8, 9, 13, 16, 19, 20, 25, 26, 32, 35, 37, 41, 46, 47, 51, 53, 57, 60, 62, 65
3	0.9	5, 6, 10, 14, 17, 18, 23, 24, 27, 28, 33, 34, 38, 39, 44, 45, 52, 54, 55, 59, 63
Transformer type	Rating (MW)	Load points served
1	0.6	3, 16, 17, 28, 29, 31 ,37, 38
2	1.0	1, 2, 4-7, 11-13, 15, 18, 20-26, 30, 32-36
3	1.2	8-10, 14, 27

Table 4.7
Case study information. DG locations were chosen randomly. Power output is given in MW and is not the rating of the DG.

DG	Case I	Case II	Case III	Case IV
A	9.5236	4.8109	3.2400	2.4546
B	0	4.8042	3.2333	2.4478
C	0	0	3.2235	2.4381
D	0	0	0	2.3875
Total	9.5236	9.6151	9.6968	9.7280
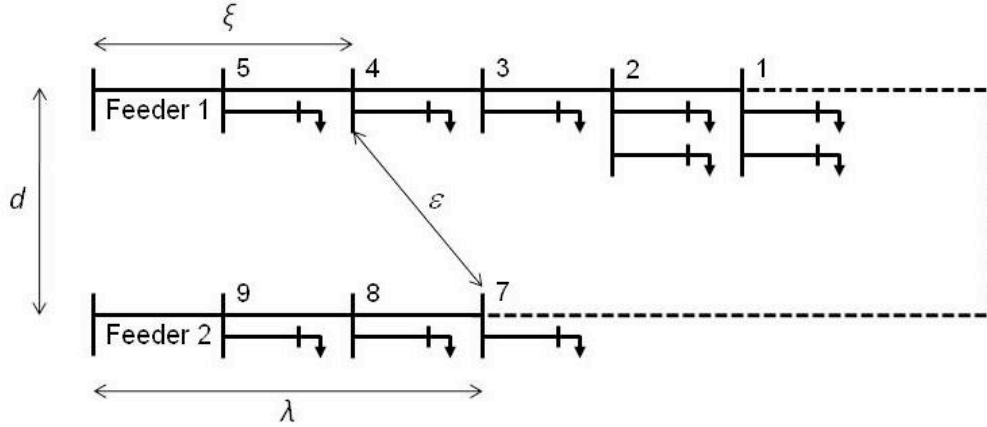
Figure 4.15. Geometric measurements of feeders. The quantities d, ξ, and λ are used to calculate the distance of a possible connection, ε.

For all connections, the ACSR Flamingo conductor was chosen. The data for this conductor is shown in Table 4.8, adapted from [133]. The assumed cost was $\$0.2\times10^6$ per km on a synthetic cost base for the possible connections. The *.aux* file containing the details of the possible connections was built using an automated custom Matlab function, called *CreateAux()*. This function, along with the modeling files and additional code is included in the electronic appendix for Volume IA (see Appendix II). SimAuto was able to load the possible connections into the system shown in Fig. 4.14 and the status of the line was switched from 'Open' to 'Closed' during the optimization. Next, the results of the sequential feeder method and the multi-objective GA applied to the RBTS will be discussed for the four case studies.

Table 4.8
ACSR Flamingo data. All data reproduced from [133].

Diameter	666600 cmils
Current rating	800 A
Resistance	0.141 Ω/mi
Impedance	0.412 Ω/mi
Assumed cost	$\$0.2\times10^6$

4.3.2   *Results of the sequential feeder method for the RBTS*

The sequential feeder method was applied in two different ways to each case of the RBTS Bus 3 distribution system. The first application is no different than that described for the 3FDR test system. The second application begins by closing all normally open switches before running the algorithm. This assumption attempts to more closely approximate how an actual utility would proceed – using existing connections to their maximum benefit before constructing new connections between feeders. The second

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application of the sequential feeder method as described shall be known as the "modified sequential feeder method." All base case ENS calculations assumed a system ASAI of 0.999375 [78], corresponding to a yearly outage time of 5.475 hours.

Case I. The base ENS of this case was 64.41 MWh. The first application of the sequential feeder method resulted in two possible connections for the first connection to be made: buses *17* to *23* and buses *18* to *24*. Both had the same cost of $0.2010×10^6$ and reduced the ENS to 50.75 MWh. The connection between buses *17* and *23* was made permanent. The second proposed connections were from buses *1* to *23* and buses *3* to *25*, lowering the ENS to 37.04 MWh. The connection between buses *1* and *23* was selected for the topology modifications. The total cost of the proposed connection was $1.0012×10^6$. The solution space is shown in Fig. 4.16, and the chosen connections based on those proposed from the sequential feeder method are shown as part of the topology in Fig. 4.17. When the normally open lines are closed, the solution space appears as shown in Fig. 4.18. Before, the solution space was spread into three clusters with ENS values around 65 MWh, 52 MWh, and 37 MWh. When the normally open lines are closed before the sequential feeder method is applied, the solution space is reduced to two clusters: those of 52 MWh and 37 MWh. In this case, the least optimal cluster was eliminated by first closing the normally open lines. The base ENS of the modified sequential feeder method was 51.33 MWh. The proposed connections were the same for the first connection, and again the connection between buses *17* and *23* was made permanent. However, in this case the first connection lowered the ENS to 34.575 MWh. The second proposed connection was between buses *5* and *9*, but barely reduced the ENS to 34.565 MWh at a total cost of $0.4098×10^6$. It is decided by the decision maker that the second connection will not be made and the new topology is shown in Fig. 4.19. The small difference in the ENS between the first and second additions is due to lower losses associated with the second connection.

Case II. The base ENS of the second case, with two DGs, located on bus *23* on feeder 5 and bus *8* on feeder 2, is 52.94 MWh. The solution space after the application of the sequential feeder method is shown in Fig. 4.20; the candidate solutions are clustered in five distinct regions. The first proposed connection is between buses *1* and *7* and corresponds to closing the normally open line at no cost to reduce the ENS to 43.04 MWh. The second proposed connection is between *15* and *25* and reduces the ENS to 34.14 MWh at a cost of $0.5381×10^6$. It is determined that both proposed connections will be made and the proposed topology is shown on the RBTS Bus 3 topology in Fig. 4.21. Closing all the normally open lines as part of the modified sequential feeder method decreased the base ENS to 34.17 MWh. The modified method proposed a connection between buses *15* and *19* to decrease the ENS to 34.16 MWh. Clearly, as shown in the solution space of Fig. 4.22, the ENS cannot be much improved beyond the base case. The proposed connection is shown in Fig. 4.23 and it is seen that it connects two

feeders already tied by a normally open switch. The reason the ENS is slightly lower for this case is that the additional connection makes a small decrease in the amount of system losses.
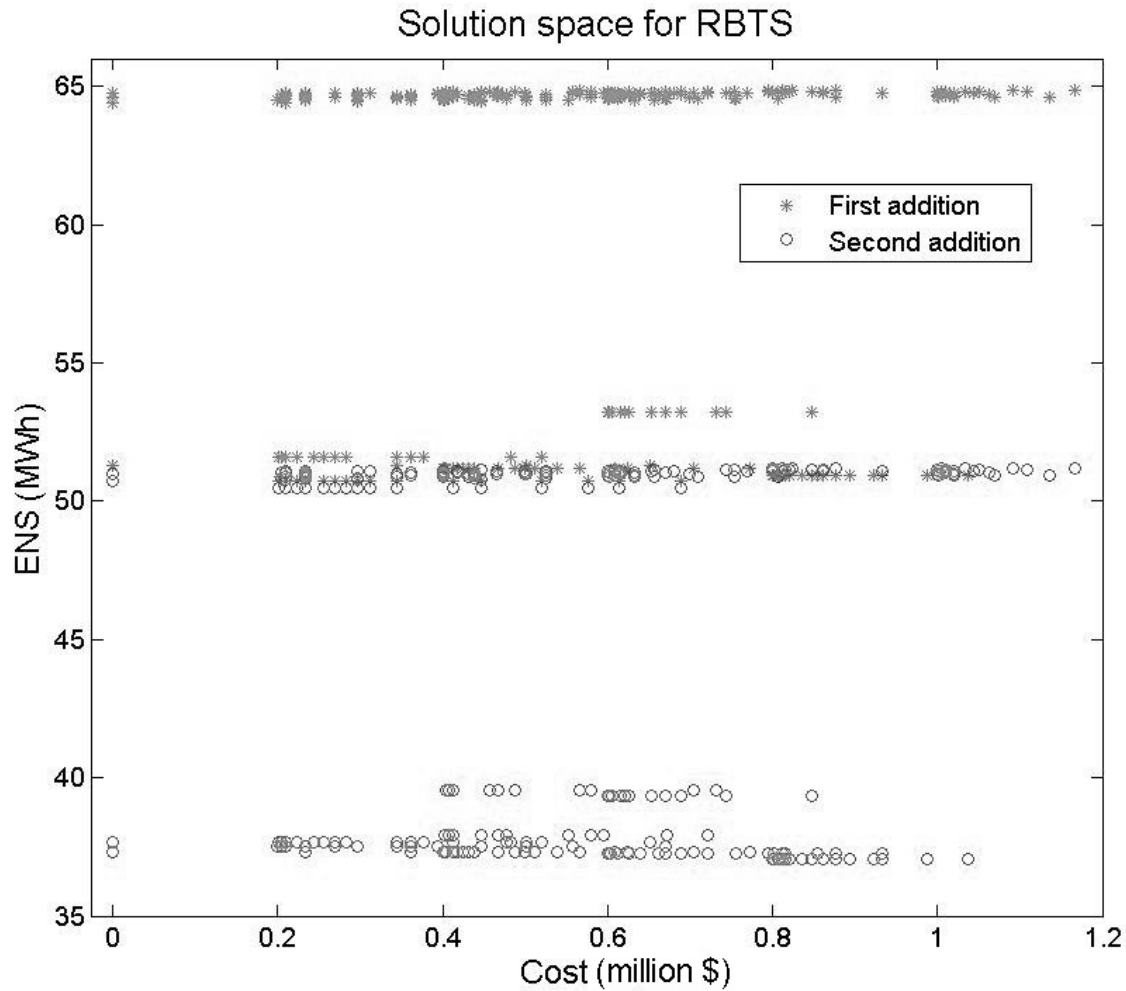
Figure 4.16. The solution space of the sequential feeder method applied to RBTS Case I. The connections that were chosen between for the first connection are shown as '*'s and the choices for the second connection are shown as 'o's.
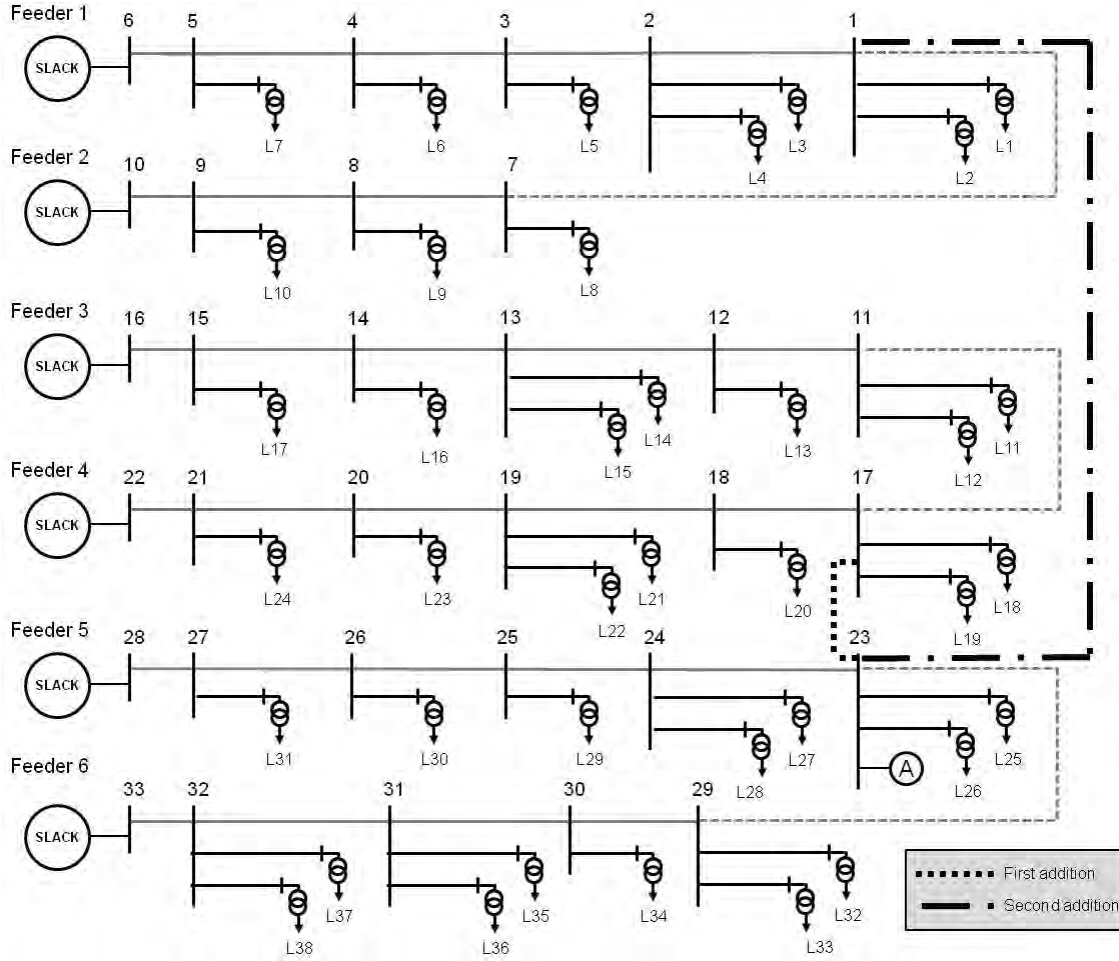
Figure 4.17. Proposed connections from the sequential feeder method applied to RBTS Case I. The normally open lines are open and shown by dashed grey lines.

Case III. The base ENS of this case is 39.55 MWh, and generators are integrated into the system at points A, B, and C. The output of the sequential feeder method proposes the connection between buses *8* and *14* at a cost of 0.2040 p.u. to reduce the ENS to 36.53 MWh. The next proposed connection is between buses *9* and *25* to reduce the ENS to 34.50 MWh, at a total project cost of 0.8748×10^6. The solution space for the first and second connections is shown in Fig. 4.24. The solutions are arranged in bands of ENS values. It is likely that the utility would consider the second addition to not be worth the cost. The proposed topology of the first connection from the sequential feeder method is shown in Fig. 4.25. When the modified sequential feeder approach is applied to Case III, the base ENS decreases to 37.54 MWh. The solution space is shown in Fig. 4.26, and it is seen that the solution space of the modified method again eliminates the least optimal stripes from the original solution space. By closing all the normally open lines, the solution space is more spread than striped. The first proposed connection is between buses *9* and *27* at a cost of 0.6000×10^6 and reduces the ENS to 33.81 MWh. After the first connection is made permanent, the second proposed connection is between buses *15* and *19* at a cost of

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$\$0.3606\times10^6$, reducing the ENS to 33.80 MWh. Again, the second connection proposed by the modified sequential feeder method does not appear as though it would be chosen by the utility because of the high cost and small improvement in reliability. The proposed topology with only the first connection is shown in Fig. 4.27.
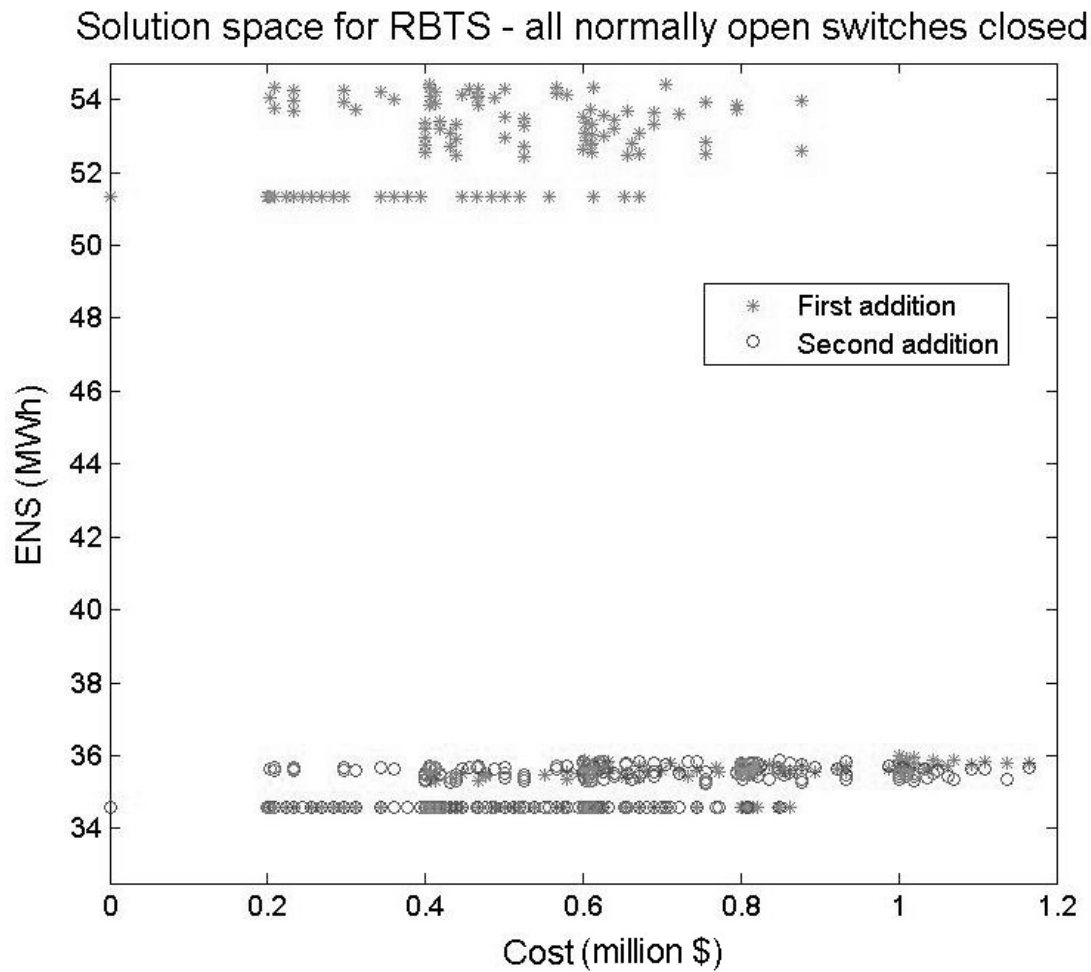
Figure 4.18. The alternate solution space for the sequential feeder method applied to the RBTS Case I. Notice the difference in the cluster pattern of the possible connections.
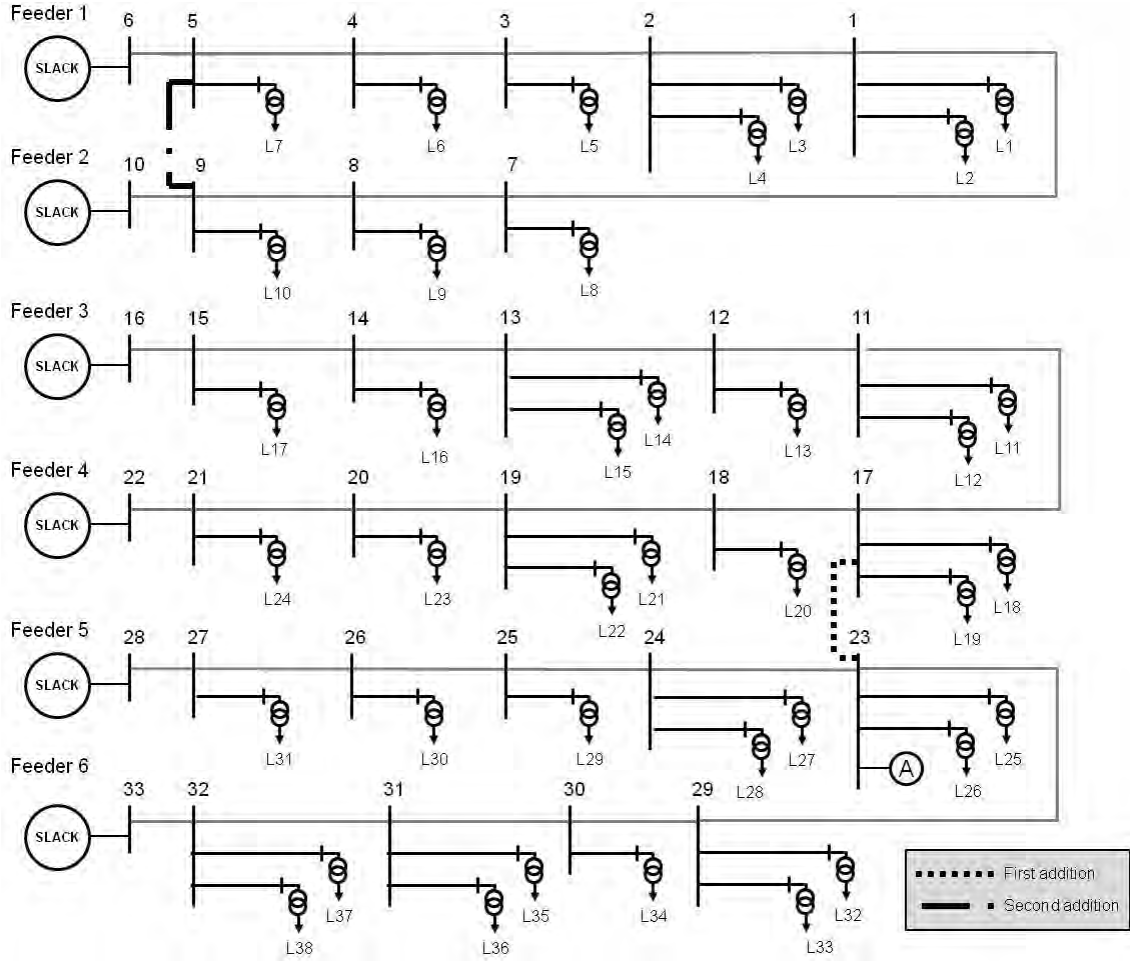
Figure 4.19. Proposed topology from the modified sequential feeder method applied to RBTS Case I. The normally open switches are closed.

Case IV. Splitting the DG sources between positions A, B, C, and D results in an arrangement characterized by feeder loads that exceed the output of the DG. In other words, the DGs' outputs are smaller than the loads on the feeders where they are located. When this happens, the sequential feeder method is unable to increase the reliability by more than a small amount, which is related to losses. The sequential feeder method would be unable to decrease the ENS because the ENS is calculated based on the slack bus output of feeders with unmet demand.

4.3.3 *Results of the multi-objective GA for the RBTS*

Based on a subjective understanding derived from trial simulations, it was found that the Pareto front approximated by the GA was repeatable after 15 generations. Thus, 15 generations was considered as the stopping criterion for the simulations. Each case was simulated three times for redundancy, and each

simulation yielded the same Pareto front. The run times for the simulations presented in the following results are shown in Fig. 4.28 for a non-devoted Intel® Core™ 2 Duo CPU at 2.80 GHz. To remind the reader, the long run time is primarily a result of having to reset the server to SimAuto each time the fitness function is evaluated.
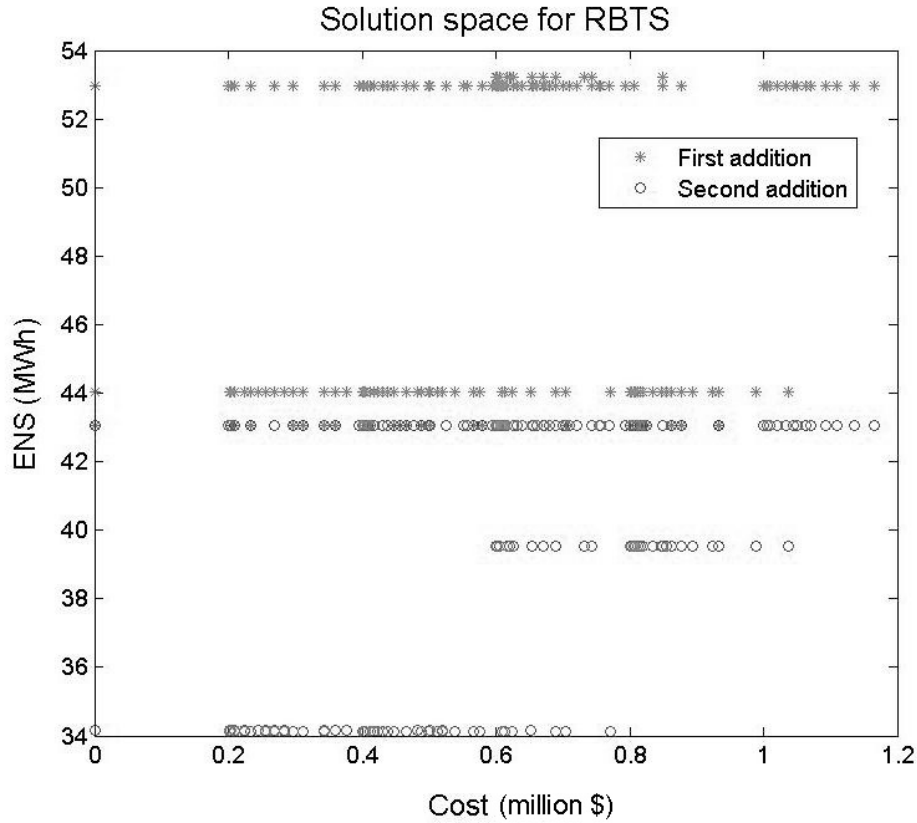
Figure 4.20. The solution space of the sequential feeder method applied to RBTS Case II. The connections that were chosen between for the first connection are shown as '*'s and the choices for the second connection are shown as 'o's.

Case I. The Pareto front approximated by the multi-objective GA applied to Case I on the RBTS is shown in Fig. 4.29 and the solutions are detailed in Table 4.9; the same front was achieved with all simulations. The base case ENS of Case I is 64.41 MWh. The lowest cost topology (solution point 1 in Table 4.9) was to close the normally open line between buses *23* and *29* at no cost to reduce the ENS to 51.28 MWh. The remaining five solution points on the front differ by 7.2×10^{-3} MWh around an ENS of 34.54 MWh. It is likely, then, that the second solution point with a cost of $\$0.2010\times10^{6}$ and an ENS of 34.54 MWh would be chosen. This corresponds to closing the normally open lines between buses *11* and

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17 and between buses *23* and *29*, and constructing a line between buses *17* and *23*. This chosen topology is shown in Fig. 4.30.
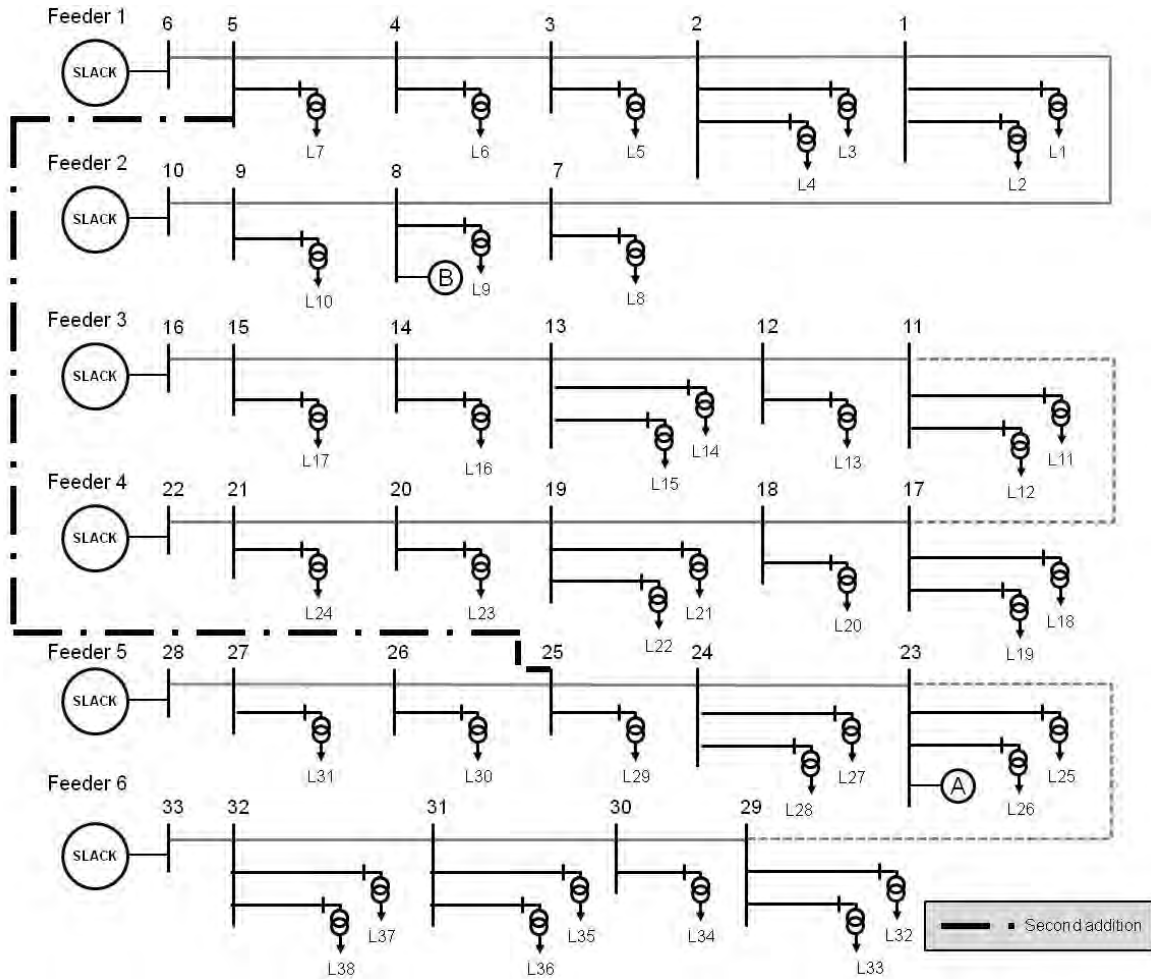
Figure 4.21. Topology of solution offered by the sequential feeder method for the RBTS Case II. Two of the normally open switches are open and shown by grey dashed lines. The first addition was the closing of the normally open line between *1* and *7*.

Case II. The application of the multi-objective GA to Case II of the RBTS resulted in the Pareto front shown in Fig. 4.31. The solution details are given for each point in Table 4.10. The points differ by 5.2×10^{-3} MWh around an ENS of 34.14 MWh. The base ENS of Case II is 52.97 MWh, so all of the solution points on the Pareto front represent topologies with approximately the same improvement in reliability. As a result, the cheapest solution – point 1 – will be chosen. The chosen topology is shown in Fig. 4.32 and corresponds to closing the normally open lines between buses *1* and *7* and between buses *23* and *29*. The ENS is reduced to 34.15 MWh at zero cost.

Case III. The base ENS of the case with three DGs spread throughout the RBTS Bus 2 distribution system is 39.55 MWh. The approximated Pareto front is shown in Fig. 4.33 and the details of all the solution points are given in Table 4.11. The first two solution points reduce the ENS to 37.5 MWh and the rest of the solutions differ by 16.18×10^{-3} MWh around an ENS of 33.79 MWh. The difference in cost between solution points 2 and 3 is only 0.003 p.u., while solution point 3 has an ENS that is 3.71 MWh lower. Thus, the solution that would be chosen is solution point 3, which lowers the ENS to 33.80 MWh at a cost of 0.2040 p.u. Solution point 3 corresponds to closing the normally open lines between buses *1* and *7* and between buses *23* and *29*, and adding a connection between buses *8* and *14*. The topology is shown in Fig. 4.34.
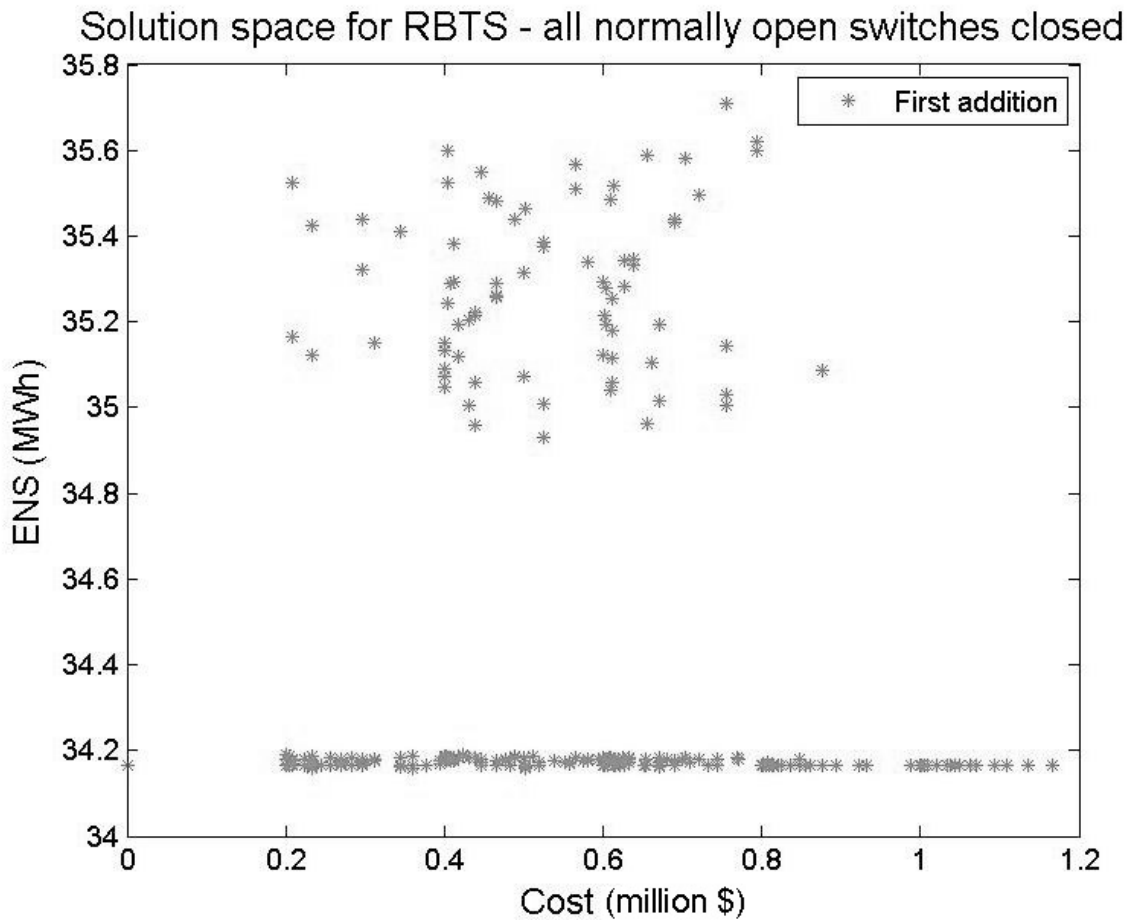
Figure 4.22. The solution space of the modified sequential feeder method applied to RBTS Case II. The connections that were chosen between for the first connection are shown as '*'s and the choices for the second connection are shown as 'o's
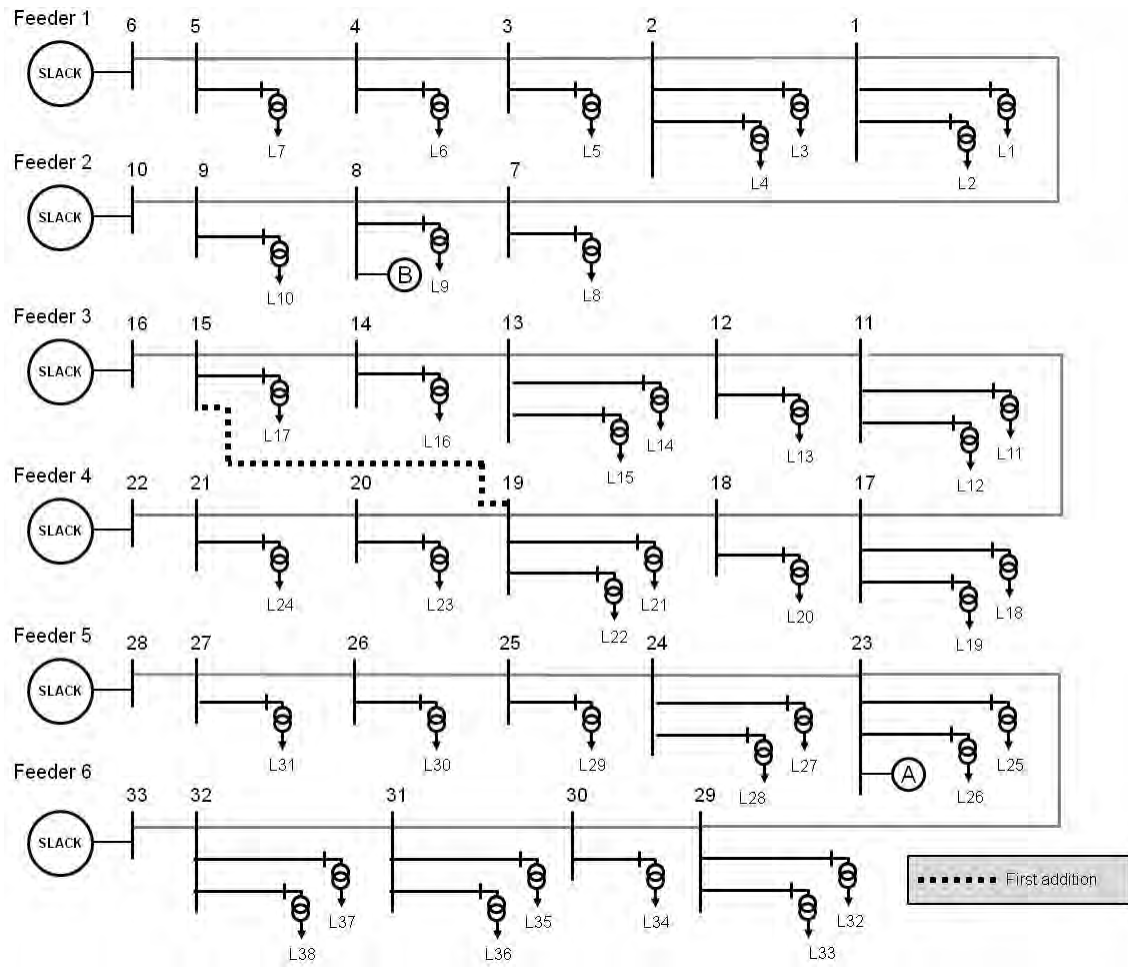
Figure 4.23. Topology of solution selected from the modified sequential feeder method applied to Case II of the RBTS. The normally open switches are closed.

Case IV. The distribution of the generators in this case is such that the feeder loads where the DGs are located is greater than the DG output. Thus, the ENS cannot be improved beyond a small amount, which is related to losses. The GA is not applicable for the feeder addition problem when the DG output is less than the feeder loads where the DGs are located.
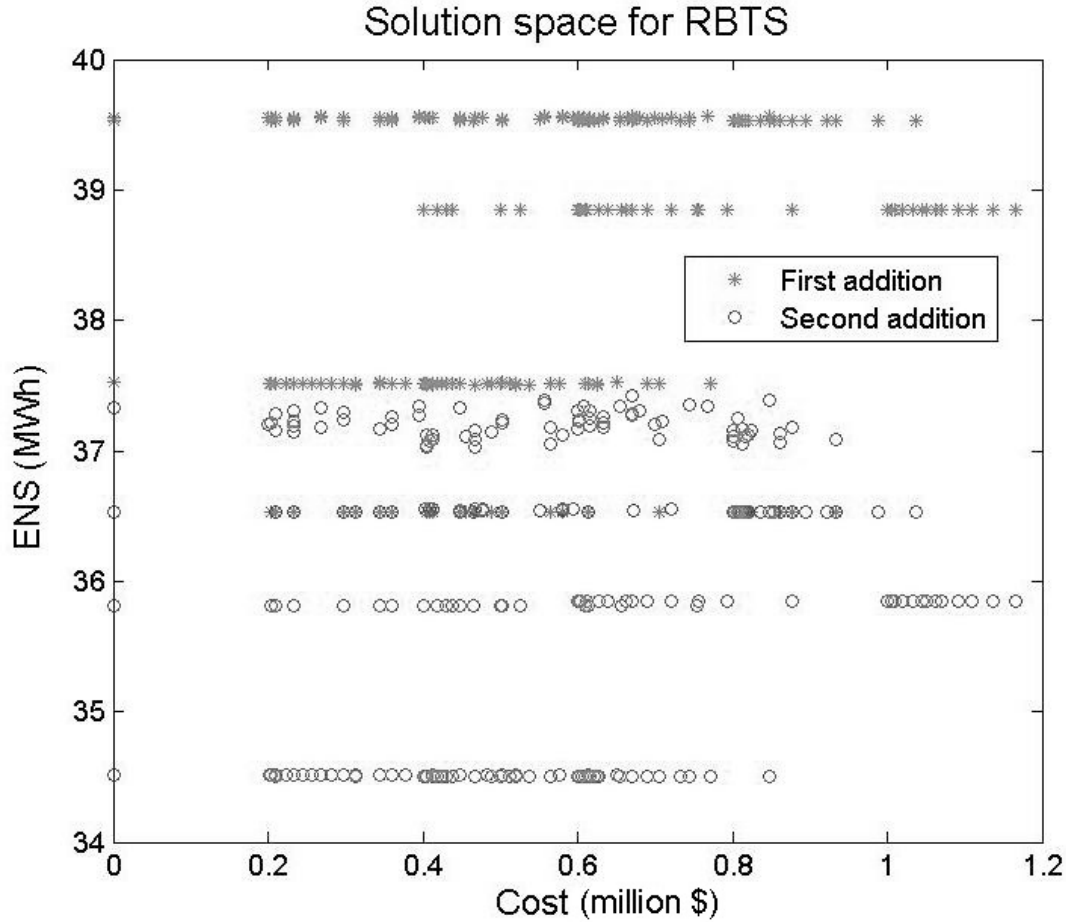
Figure 4.24. Solution space of the sequential feeder method applied to Case III of the RBTS.

4.3.4 *Discussion of the RBTS simulations*

On the more complex system of the RBTS, it is seen that the results of the sequential feeder method and the GA do not agree. The normally open lines on the RBTS added an opportunity to modify the sequential feeder method by first closing all normally open lines, and then looking for possible connections. The modified sequential feeder method was able to approximate the reliability of the chosen solution from the GA. A comparison of the final solutions chosen from each method is given in Table 4.12. Graphs comparing the objectives found for each case using the different methods are shown in Fig. 4.35 (cost) and Fig. 4.36 (reliability). For a system with normally open tie switches, the sequential feeder method *must* be modified as discussed – otherwise, the solutions offered are sub-optimal.

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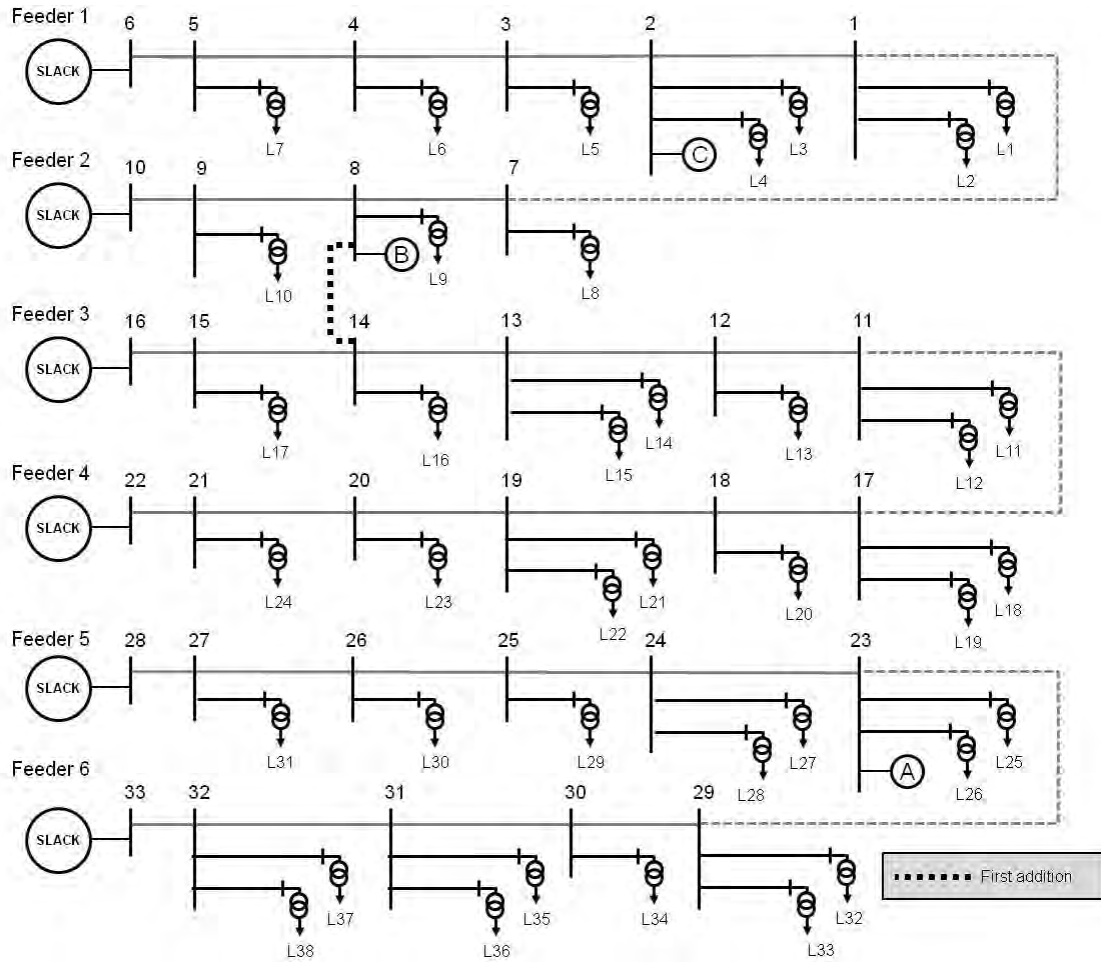
Figure 4.25. Topology of solution offered by the sequential feeder method applied to Case III of the RBTS. The normally open switches are open and shown by grey dashed lines.

4.4 Summary of simulations

The sequential feeder method and multi-objective GA were applied to a simplified test system – the 3FDR, and a more complex system – the Bus 3 distribution system of the RBTS. It was found that the solution offered by the sequential feeder method agreed with that of the multi-objective GA for the 3FDR. On the more complex system, it was found that the sequential feeder method had to be modified by closing all normally open lines in the system, before entering the optimization. The un-modified sequential feeder method results in sub-optimal solutions; the modified method agreed better with the chosen solution of the multi-objective GA. For cases I-III, it was possible to increase the reliability measure of ENS by using the optimization methods to choose connections between feeders. For Case IV, it was found that no connections would improve the reliability because the output of each DG was less than the load of the feeder on which it was located.

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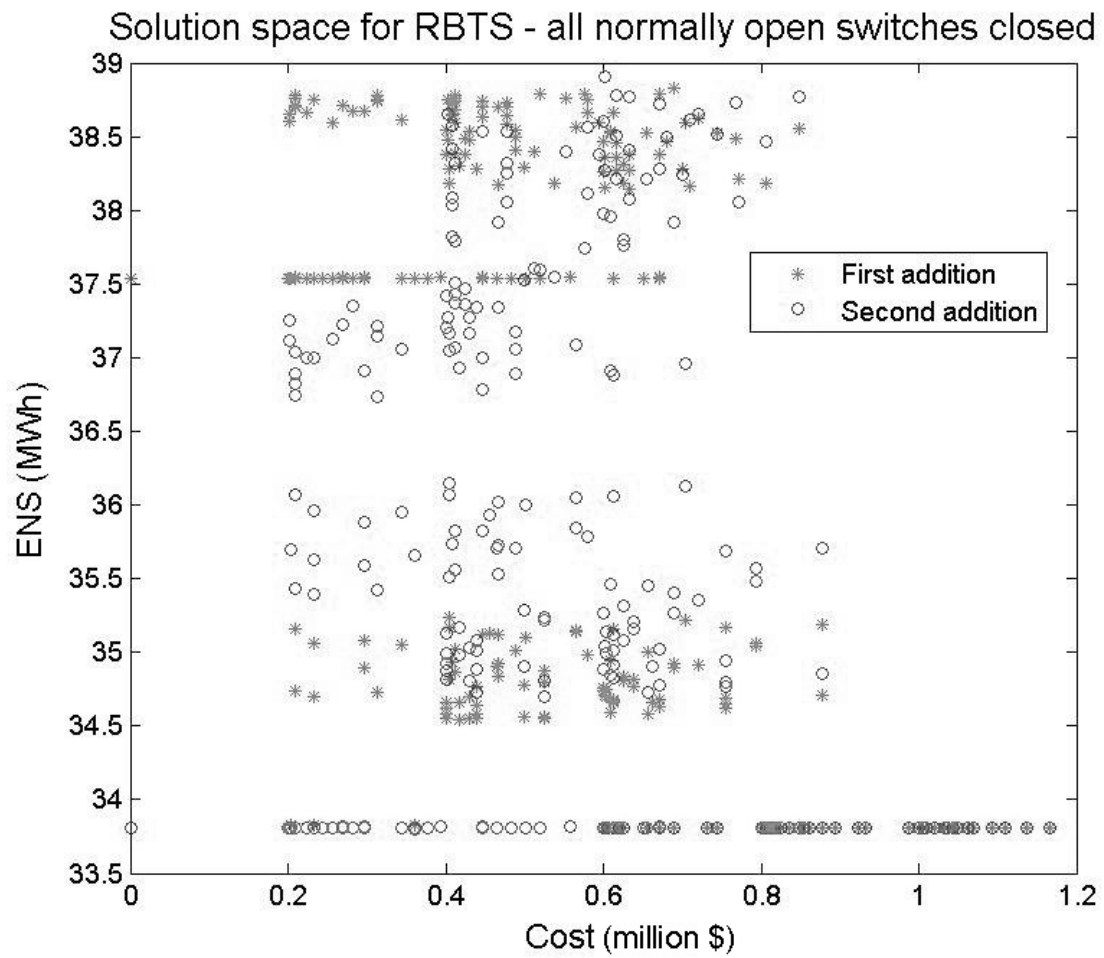
Figure 4.26. Solution space of the modified sequential feeder method applied to Case III of the RBTS. The normally open switches are open and shown by grey dashed lines.
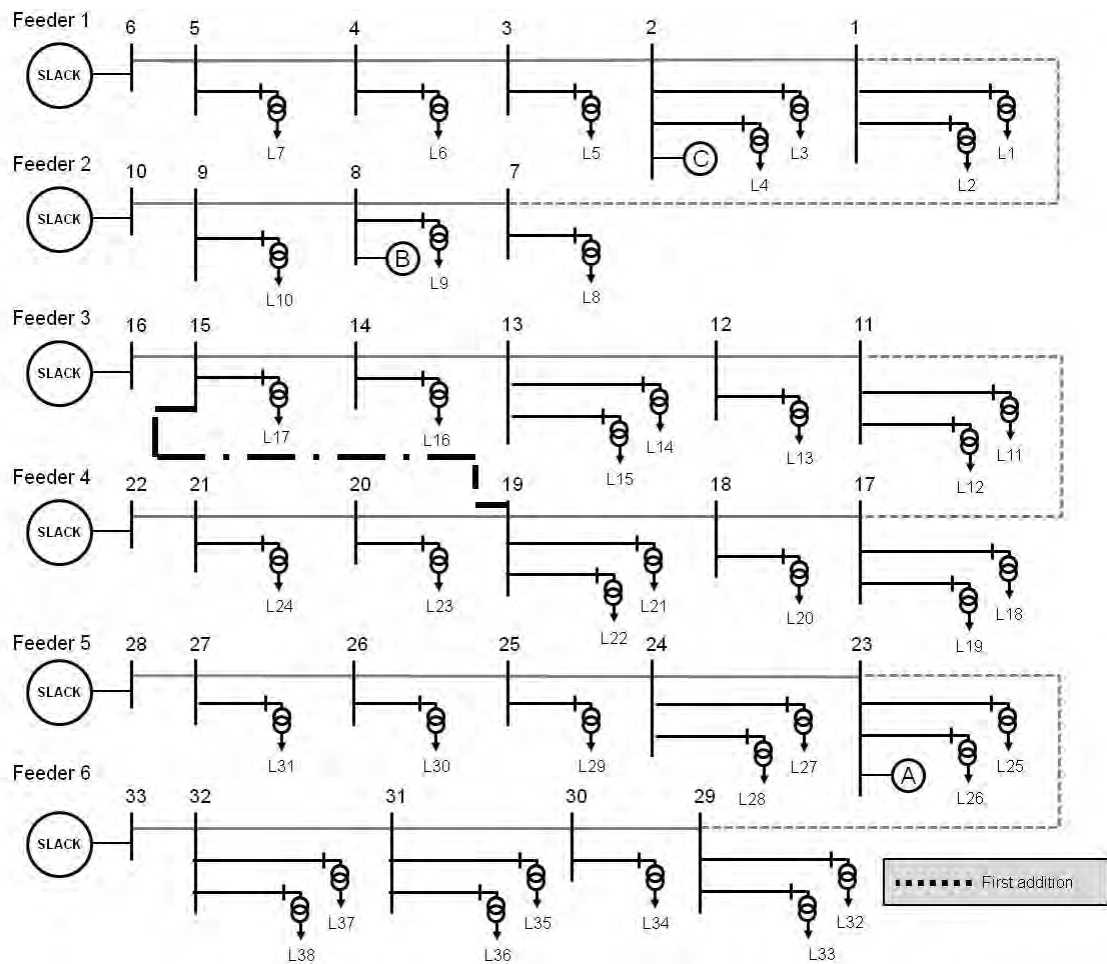
Figure 4.27. Topology of solution offered by the modified sequential feeder method applied to Case III of the RBTS. The normally open switches are closed.
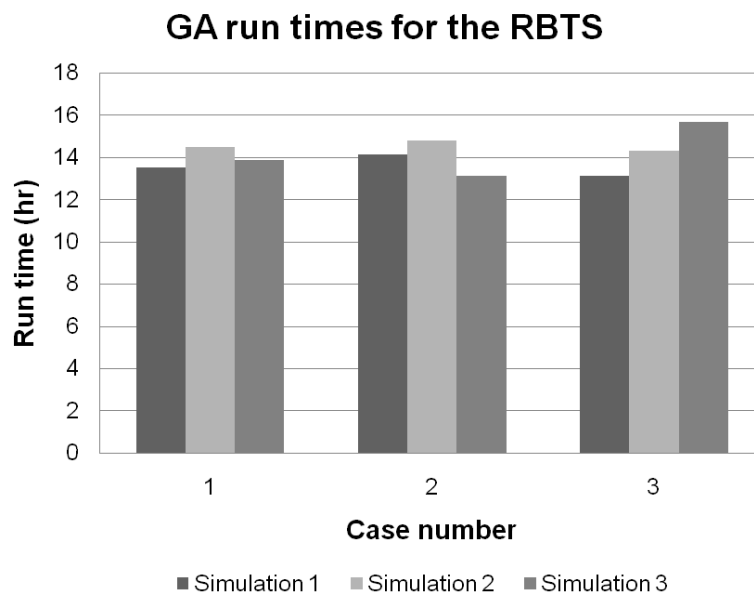
Figure 4.28. Simulation times of the GA applied to the RBTS, with a 15 generation stop criterion.
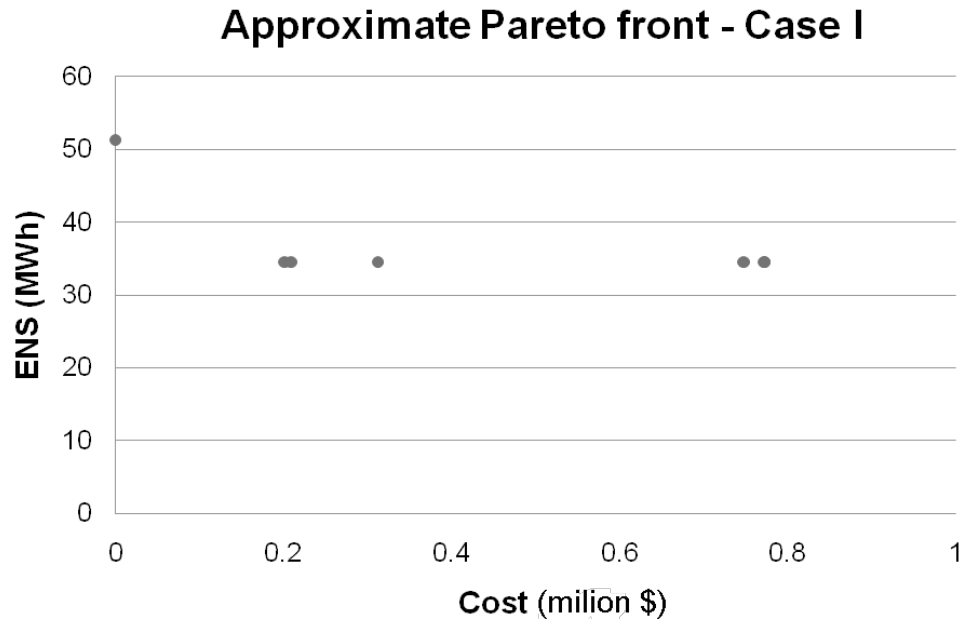
Figure 4.29. Pareto front for Case I of the RBTS.

Table 4.9
Solution details of the Pareto front for Case I of the RBTS. The chosen solution is shown in bold.

Solution point	ENS (MWh)	Cost (million $)	Connection (to, from)		Cost (million $)
1	51.28	0.0000	23	29	0.0000
2	**34.54**	**0.2010**	**11**	**17**	**0.0000**
			17	**23**	**0.2010**
			23	**29**	**0.0000**
3	34.54	0.2088	11	17	0.0000
			20	27	0.2088
			23	29	0.0000
4	34.54	0.3124	11	17	0.0000
			21	26	0.3124
			23	29	0.0000
5	34.54	0.7469	15	26	0.5381
			21	27	0.2088
			23	29	0.0000
6	34.54	0.7713	11	17	0.0000
			14	19	0.2332
			15	25	0.5381
			23	29	0.0000
7	34.54	0.7724	15	19	0.3606
			21	25	0.4118
			23	29	0.0000

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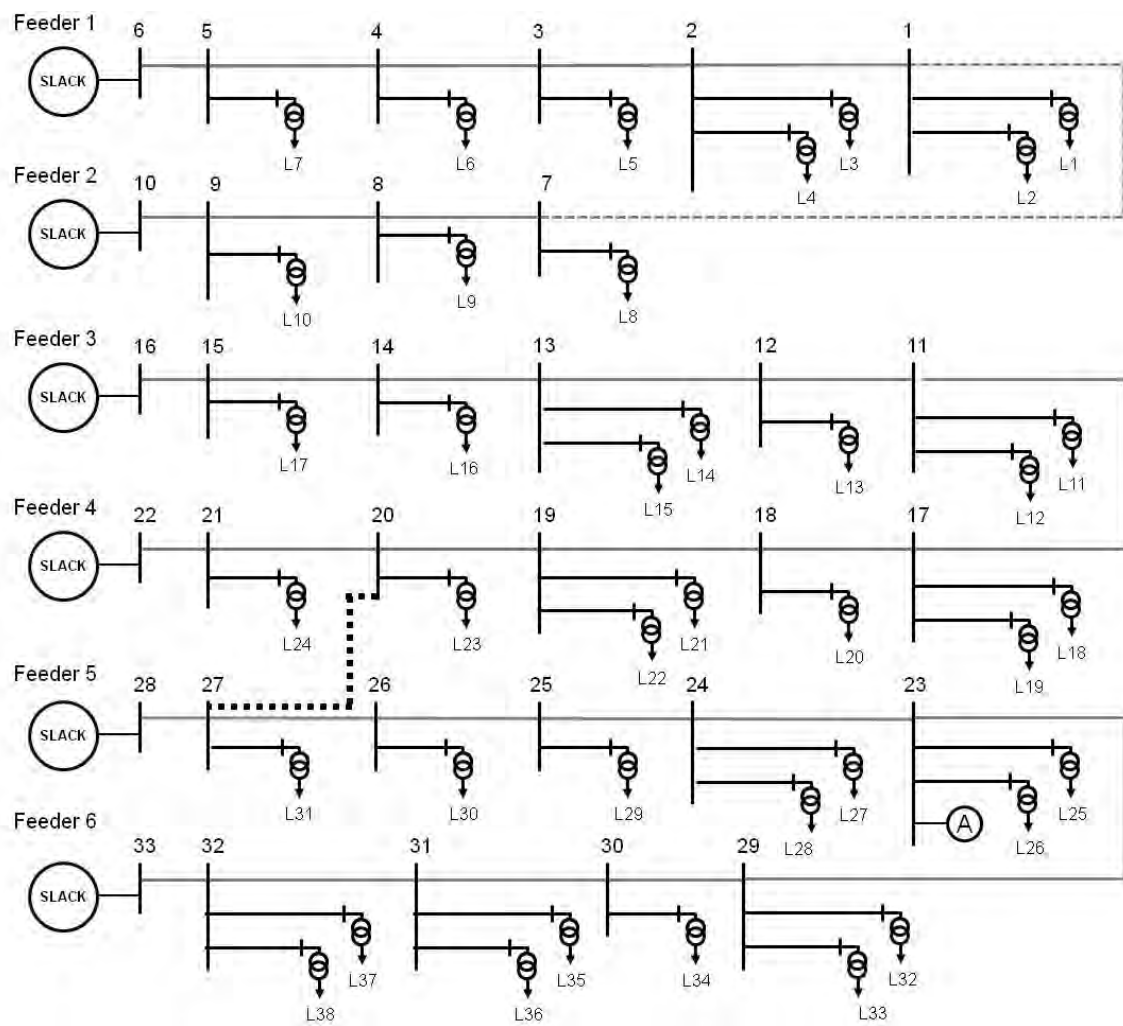
Figure 4.30. Chosen solution topology from the GA applied to Case I. The normally open lines between buses *11* and *17* and between buses *23* and *29* are closed (solid grey), and the proposed additional connection is shown as a black dotted line.
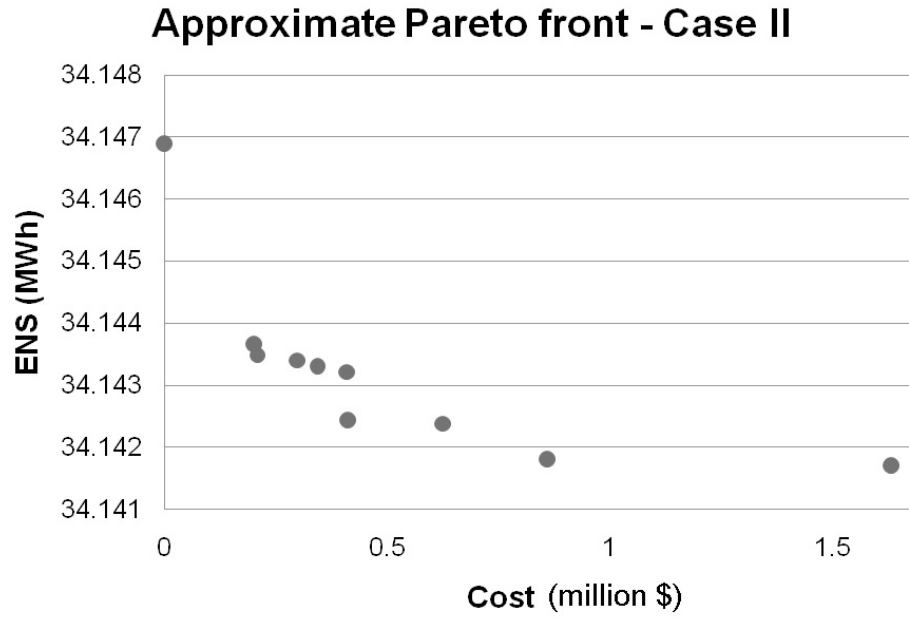
Figure 4.31. Pareto front for Case II of the RBTS.

Table 4.10
Solution details of the Pareto front for Case II of the RBTS. The chosen solution is shown in bold.

Solution point	ENS (MWh)	Cost (million $)	Connection (to, from)		Cost (million $)
1	**34.15**	**0.0000**	**1**	**7**	**0.0000**
			23	**29**	**0.0000**
2	34.14	0.2010	1	7	0.0000
			18	24	0.2010
3	34.14	0.2088	1	7	0.0000
			19	25	0.2088
4	34.14	0.2973	1	7	0.0000
			18	26	0.2973
5	34.14	0.3441	1	7	0.0000
			17	25	0.3441
6	34.14	0.4098	5	9	0.2088
			18	24	0.2010
7	34.14	0.4118	1	7	0.0000
			21	25	0.4118
8	34.14	0.6248	1	7	0.0000
			15	24	0.6248
9	34.14	0.8590	5	7	0.4472
			21	25	0.4118
10	34.14	1.6309	2	18	0.6030
			8	25	0.6161
			21	25	0.4118

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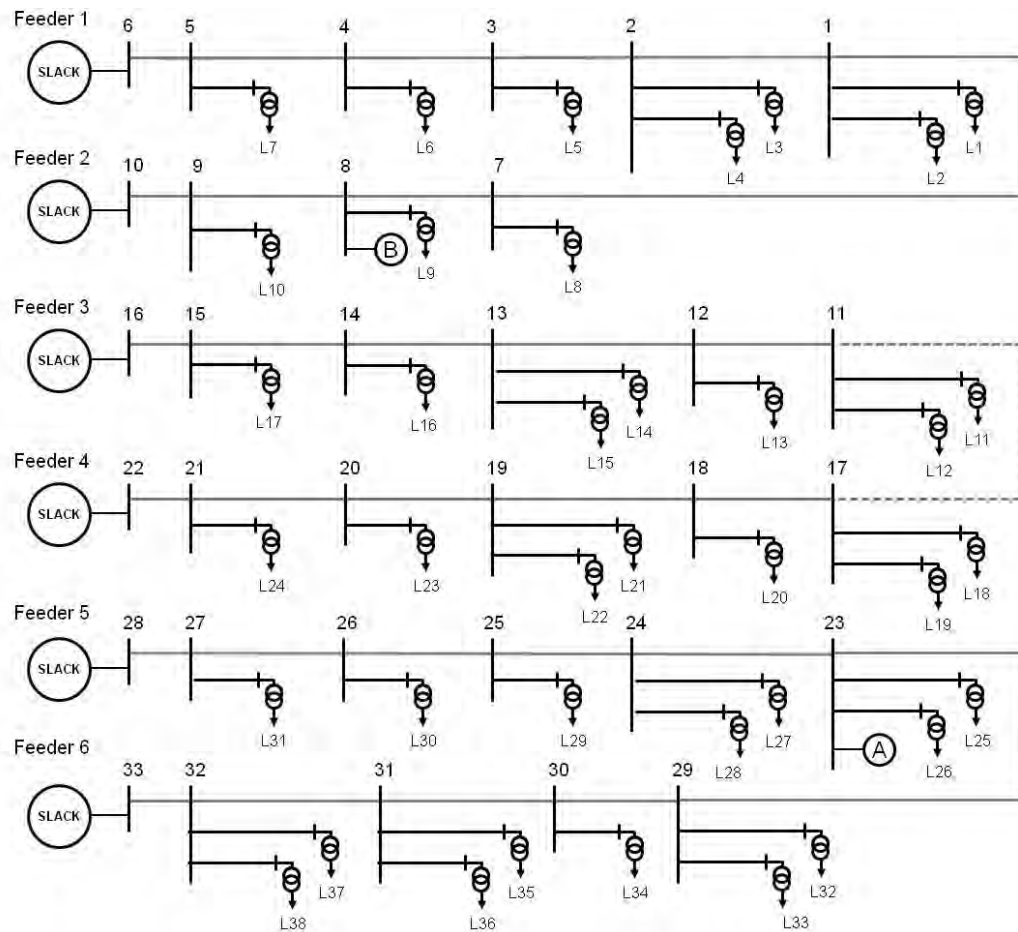
Figure 4.32. Chosen solution topology from the GA applied to Case II. The normally open lines between buses *1* and *7* and between buses *23* and *29* are closed (solid grey).
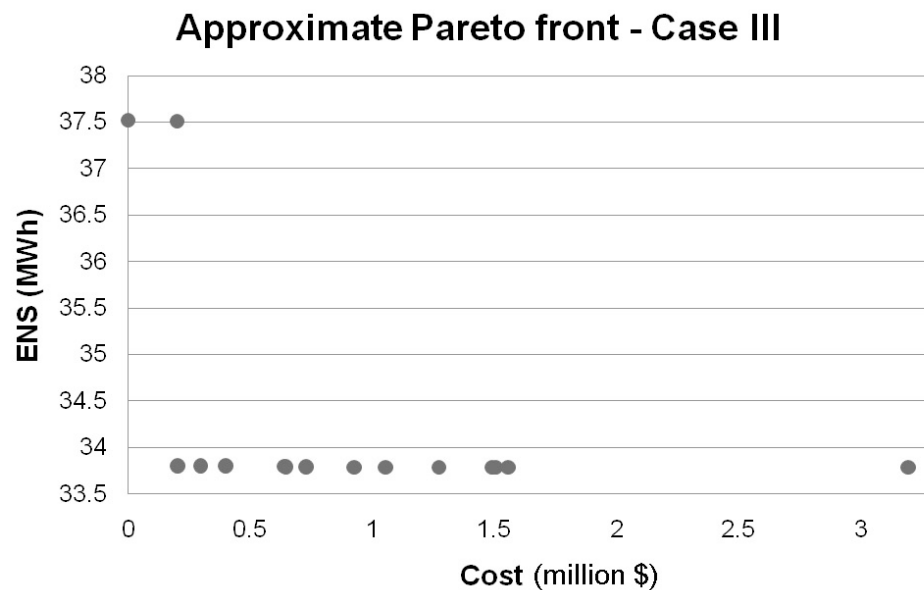
Figure 4.33. Pareto front for Case III of the RBTS.

Table 4.11

Solution details of the Pareto front for Case III of the RBTS. The chosen solution is shown in bold.

Solution point	ENS (MWh)	Cost (million $)	Connection (to, from)		Cost (million $)
1	37.52	0.0000	23	29	0.0000
2	37.51	0.2010	18	24	0.2010
3	**33.80**	**0.2040**	**1**	**7**	**0.0000**
			8	**14**	**0.2040**
			23	**29**	**0.0000**
4	33.80	0.2973	1	7	0.0000
			8	15	0.2973
			23	29	0.0000
5	33.80	0.4000	1	7	0.0000
			4	14	0.4000
			23	29	0.0000
6	33.80	0.6396	1	7	0.0000
			3	12	0.4386
			27	32	0.2010
7	33.79	0.6474	1	7	0.0000
			3	12	0.4386
			21	27	0.2088
8	33.79	0.7281	1	7	0.0000
			8	15	0.2973
			11	24	0.4308
9	33.79	0.9269	1	7	0.0000
			3	12	0.4386
			13	27	0.4883
10	33.79	1.0539	1	7	0.0000
			3	13	0.4000
			8	24	0.6439
11	33.79	1.2736	4	12	0.5250
			9	13	0.3441
			14	26	0.4045
12	33.79	1.4901	4	12	0.5250
			7	26	0.6210
			9	13	0.3441
13	33.79	1.5060	5	9	0.2088
			5	19	0.6708
			9	26	0.6264
14	33.79	1.5559	4	12	0.5250
			9	26	0.6264
			14	26	0.4045

Continued next page

Solution point	ENS (MWh)	Cost (million $)	Connection (to, from)		Cost (million $)
15	33.79	3.1955	2	23	0.8122
			5	19	0.6708
			5	25	0.8773
			9	26	0.6264
			32	38	0.2088
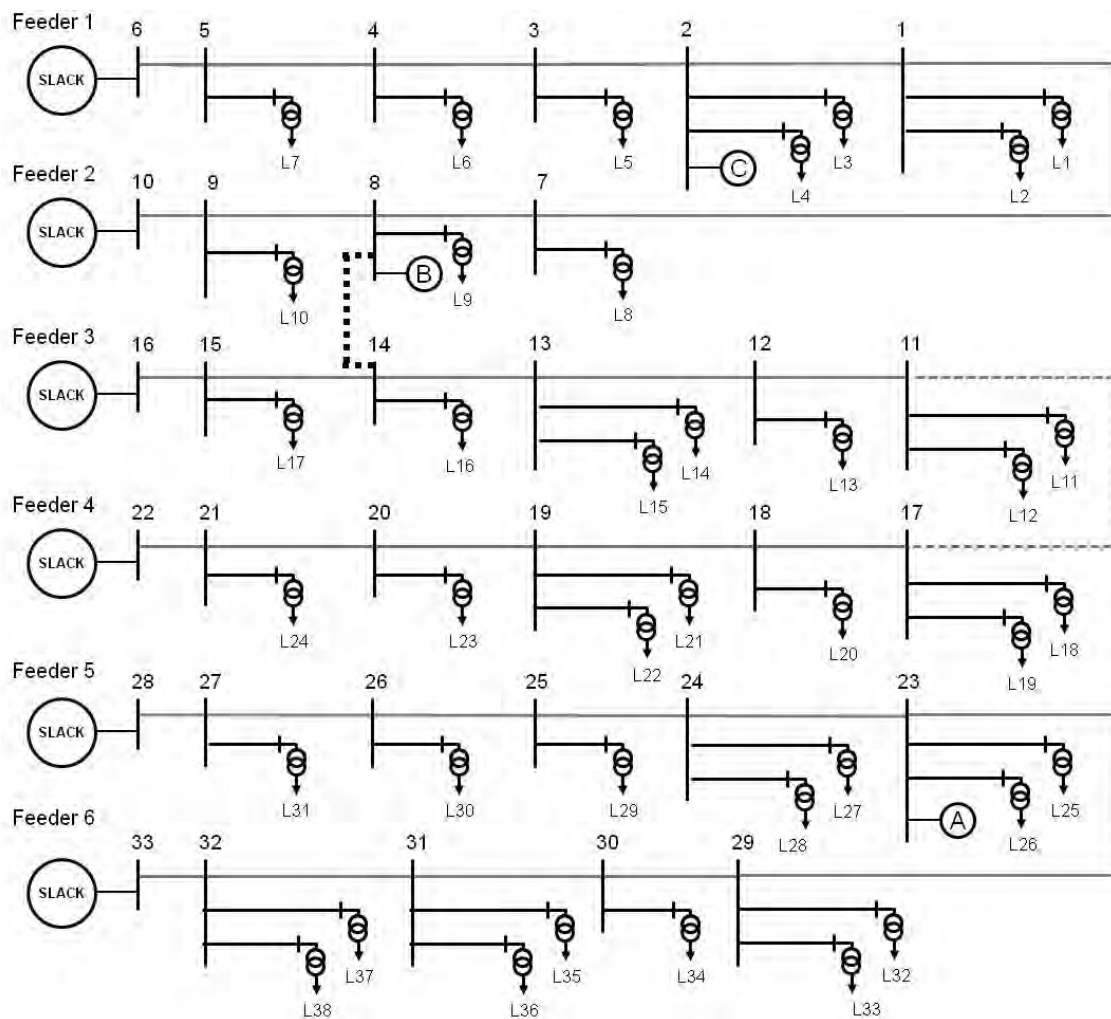
Figure 4.34. Chosen solution topology from the GA applied to Case III. The normally open lines between buses *1* and *7* and between buses *23* and *29* are closed (solid grey). The proposed new connection is shown as a black dotted line.

Table 4.12
Solution details of the RBTS.

Case	Solution method	ENS (MWh)	Total cost (million $)	Connection (to, from)		Cost (million $)
I	Sequential feeder	37.04	1.0012	1	23	0. 8002
				17	23	0.2010
	Modified sequential feeder	34.58	0.2010	1	7	0.0000
				11	17	0.0000
				17	23	0.2010
				23	29	0.0000
	GA	34.54	0.2010	11	17	0.0000
				17	23	0.2010
				23	29	0.0000
II	Sequential feeder	34.14	0.5381	1	7	0.0000
				15	25	0.5381
	Modified sequential feeder	34.17	0.0000	1	7	0.0000
				11	17	0.0000
				23	29	0.0000
	GA	34.15	0.0000	1	7	0.0000
				23	29	0.0000
III	Sequential feeder	34.50	0.8748	8	14	0.2040
				9	25	0.6708
	Modified sequential feeder	33.81	0.6000	1	7	0.0000
				9	27	0.6000
				11	17	0.0000
				23	29	0.0000
	GA	33.80	0.2040	1	7	0.0000
				8	14	0.2040
				23	29	0.0000

Cost of final solutions

■ Seqeuntial feeder method   ■ Modified sequential feeder method   ■ GA
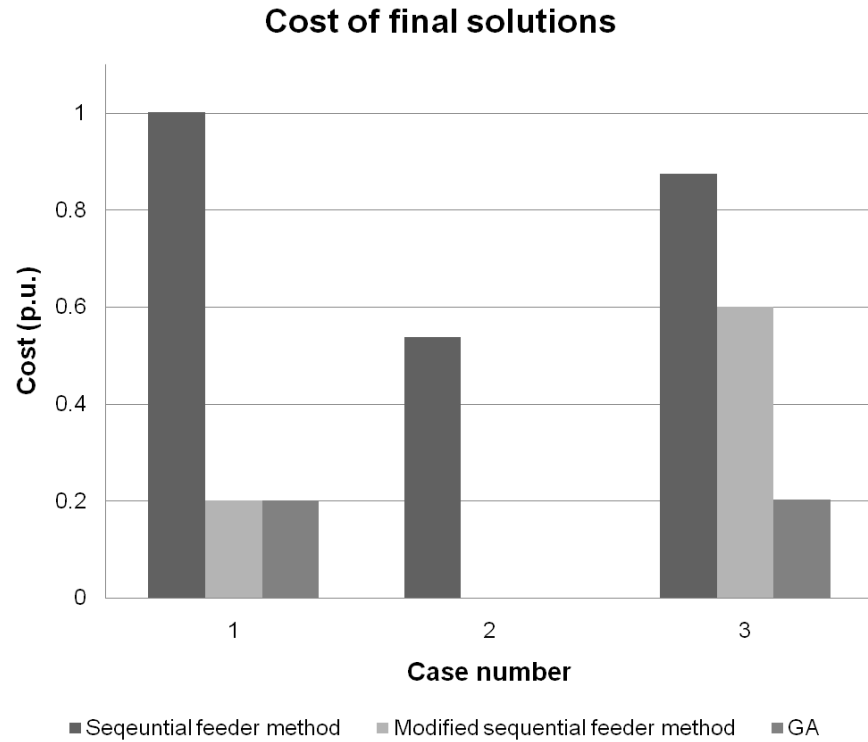
Figure 4.35. Comparison of cost objective of cost for the chosen solutions. The costs of the solutions for Case II were zero for both the modified sequential feeder method and GA.

Reliability of final solutions

■ Base topology   ■ Sequential feeder method   ■ Modified sequential feeder method   ■ GA
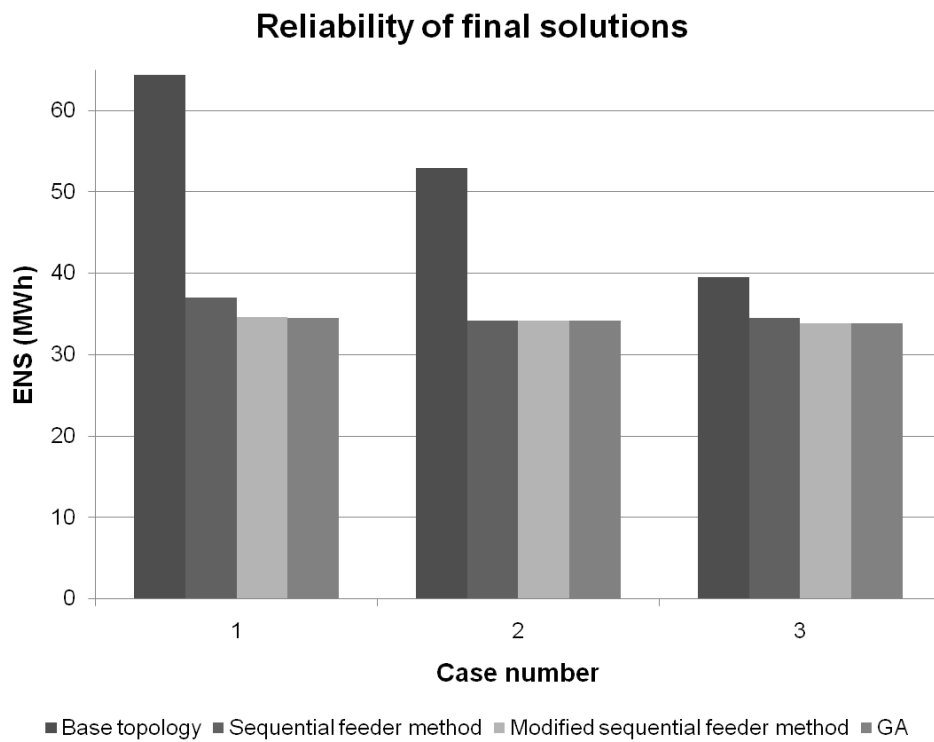
Figure 4.36. Comparison of the reliability objective for the chosen solutions.

CHAPTER 5

CONCLUSIONS AND FUTURE WORK

The work presented in this report was split into two parts: a definition of a smart distribution system based on industry input to a survey and an optimization of connections between existing feeders in the presence of DG sources. The survey requesting industry input on the definition of the smart distribution system was open for several months and the responses were described in detail in Chapter 2, the text of the survey is available in Appendix I. The mathematical formulation of the feeder addition problem and solution techniques was described in Chapter 3. Chapter 4 included the results of the optimization for two test systems. This chapter will reiterate the conclusions developed through the work described in previous chapters. Then, areas of future work will be discussed.

5.1 Conclusions

Based on the results presented in the previous chapters, several conclusions about a smart distribution system and optimization of distribution system in the presence of DGs can be made. First, the conclusions of the smart distribution survey will be presented. Then, conclusions will be drawn about the optimization procedures and test systems.

5.1.1 *A definition of a smart distribution system*

To determine a definition of a smart distribution system, a survey of industry members and academe was completed. Although some responses were divided, a basic *proposal* for the specific characteristics of a smart distribution system can be made. The following points are presented in decreasing order of importance and are reproduced for the reader's benefit from Chapter 2. A **smart distribution system**:

i. **Optimizes distributed assets** through the use of real-time pricing, AMI, two-way communicating devices, and networked connections between feeders. New market and product opportunities are enabled by plug-and-play methodologies, expected supply of ancillary services, and smart-grid tailored devices.

ii. **Incorporates DER** at all distribution voltage levels enabled with two-way communications. DER usage will be scheduled in advance and in real-time by the utility. Local management of DER will incorporate the LEMS at a minimum, but may also incorporate both the LEMS and the CDMS. DER will communicate with the smart meter, LEMS, and one another at least once per

minute. Approximately 10-19% of total generation will be met via RE resources, such as photovoltaic, biogas/biomass, CHP, and wind. Less than 50% of new DER are expected to comprise RE resources, which will be supported by battery storage and fast-starting dispatchable generation sources. DS (primarily batteries) will comprise less than 50% of rated load for up to four hours, and are expected to support up to 50% of non-dispatchable DER. Peak-shaving techniques employed primarily in the 120 V class, such as residential load control, will engage within approximately fifteen minutes.

iii. **Integrates massively deployed sensors and smart meters**. Digital sensors with incorporated intelligence are used to monitor the directions and amounts of power flow and the locations and usage patterns of DER. The sensors are expected to be located at the 15 kV class and will communicate updates at least once per minute. The sensors will be able to engage in two-way meshed communications and be enabled with control algorithms to automatically react to measurements. The smart meter acts as a communications link and a local control system and its functionality includes 1) two-way communications with the utility, as well as other devices, such as DER or CDMS or LEMS, 2) real-time reads, 3) automatic time synchronization, 4) tamper detection alarms, 5) current and voltage profiling, and 6) the capability to download and store time-of-use schedules.

iv. **Enables consumer participation in demand response** through the widespread use of dynamic pricing, with real-time signals. The utility gives the consumer limited and total control of load and generation. Demand response will engage within minutes.

v. **Uses adaptive and self-healing technologies** primarily integrated at the 15 kV class. The technologies should be able to engage in all four types of self-healing: restorative, emergency, corrective, and preventative. Self-healing will be achieved through a combination of automatic restoration and utility-supervised actions. Distribution-level self-healing actions should enable the system reliability to reach between 0.9999 (4 nines) and 0.99999 (5 nines). Technologies will activate within several cycles and will restore the system within minutes, once activated. Smart feeders will carry the responsibility for self-healing actions and will be enabled by microprocessor-based feeder automation with communications capability.

vi. **Makes use of advanced tools** (including visualization, analysis, and simulation) to streamline routine operations. A "smart" DMS will be customer-driven with the ability to 1) automatically report time-stamped smart meter measurements to the utility and use the data to plan and/or predict future usage, 2) use energy price predictions to plan future usage, 3) optimize DER and load portfolios, and 4) create back-up arrangements as contingency plans for the failure of specific components. A utility-driven DMS would store "critical" and "useful" data, with data

storage locations distributed throughout substations and/or centralized at the utility center of operations.

vii. **Integrates smart appliances and consumer devices**. Smart appliances will be smart-circuit devices and programmable devices. These devices will be two-way communication enabled and will possess control algorithms.

viii. **Possesses the ability to operate in either islanded or grid-connected mode**. A system with islanding potential should have control systems for local regulation of voltage, real power balance and reactive power balance. The utility should be able to identify islands. The ability to island would be facilitated by the implementation of controls for grid-like behavior (i.e. measuring frequency and voltage droop to control real and reactive power outputs).

The proposed definition of a smart distribution system offers only one of the many possible perspectives on the distribution-level functionality of a smart grid. At the time of writing this report, the final embodiment of the smart grid is still very much under development and debate.

5.1.2 *Optimization of feeder additions in the distribution system*

The feeder addition problem was to economically add connections between feeders in a distribution system with DG sources in order to reap maximum benefits in the system reliability during islanded operation. A heuristic technique, called the sequential feeder method, and a multi-objective GA were used to solve the optimization for two test systems. The two objectives considered were cost and reliability, measured using a slack bus-based definition of ENS. For the small test system, a third objective of loss was examined and it was determined that adding losses to the optimization was not very applicable for the feeder addition problem at this time. The third objective added to the simulation times of the GA because more generations are necessary to consistently approximate the Pareto front.

For a small test system (3FDR), the outputs of the sequential feeder method and the GA agreed. However, on the complex test system (RBTS), it was found that the results chosen from the Pareto front of the GA performed as well or better than those found using the sequential feeder method for both the cost and reliability objectives. The RBTS results were found for three of four case studies; all the case studies dealt with different arrangements of DG sources, where the total output of all DG sources was similar. To approximate the power output the DG sources, an equation developed using results from the smart distribution survey and incorporating the capacity factor of RE-based DG sources was proposed. Both of the optimization methods were able to improve the system reliability for the first three case studies. The fourth case study presented the case where the DG sources are spread throughout the system and the power output of each was less than the load on the feeders where they were located. In a system

where the DGs are not aggregated to points with higher power outputs, the addition of connections between feeders cannot improve the reliability of the system as a whole.

5.2 Future work

The area of smart grid research has been evolving at a rapid rate since this work was undertaken. Areas of future research within smart distribution systems, as identified by the completed industry survey, are in the broad areas of control, communications, self-healing functions, and the role of DER. Specifically, more research is needed into the control of smart appliances, peak-shaving devices, and islanded systems. Furthermore, the ideal amount of consumer control over devices needs to be determined. Communications systems for the DER infrastructure need further development. Communications protocols for the distribution system should be developed, as well as the data storage systems. Future work in the area of self-healing falls into the philosophy of self-healing and sensor applications. As for the role of DER, several different areas were identified as areas of future work, including LEMS operating functionality, DS and enabling technologies, scheduling techniques, and general technology developments.

The optimization techniques described in this report offer areas for further progress. With respect to the sequential feeder method, it is possible to imagine a sequential DG method. The proposed sequential DG method would identify the feeder on which a DG had the possibility of excess output, then look for the cheapest connections to nearby feeders without DGs. The development of the sequential DG method would be an area of future work. With respect to the GA, a custom algorithm may reduce the simulation times and make the search as efficient as possible. Considerations that were excluded from this initial investigation could be included into the algorithms in the future, such as protection, the stochastic nature of loads, and the stochastic nature of RE inputs for the DGs. Furthermore, the control of DG that would participate in such as system and the communications system that would allow it do so could be investigated. Another area of further investigation is the reliability measure used – how do the results change based on the reliability measure? Finally, such a system must be tested in the real world to ensure that protection systems are adequate and system stability can be maintained. Finally, techniques for re-synchronization with the grid must be developed if distribution systems incorporate DGs during outages to improve reliability.

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APPENDIX I

A SURVEY ON SMART DISTRIBUTION SYSTEMS

I. Introduction

Achieving a Smart Grid demands incorporation of intelligence at all levels of the electric grid. The American Recovery and Reinvestment Act (ARRA) of 2009, passed by 111th U.S. Congress, calls for approximately $4.5 billion for smart-grid related activities and possibly another $30 billion for projects that support smart upgrades to the electric grid. The purpose of this survey is to seek a definition of the "smart distribution system" and to identify tools and techniques from electric transmission engineering that may be used in the evolution of the "smart distribution system". The results of this survey will be shared with the community via several avenues and will be used to focus research into "the implications of the Smart Grid initiative on distribution engineering."

To complete this survey:
- Response to any question marked with an asterisk (*) is required.
- Some questions will request that you only select one option, while others will allow you to select more than one answer. If you wish to answer more than one on a single selection choice, select "other" and write in your additional response.
- For questions that require ranking, please do not rank any options equally – for example, on a question with four options, your rankings should be 1, 2, 3, 4 not 1, 1, 2, 3. Please rank all options.
- If you select "other" for any response, please provide your response in the adjacent textbox.

This survey was created by Hilary E. Brown and Dr. S. Suryanarayanan at the Colorado School of Mines under the aegis of PSERC (www.pserc.org). Thanks to Dr. G. Heydt of Arizona State University and Dr. A. Dominguez-Garcia of the University of Illinois for their assistance.

1. What is your affiliation? *Please select one option.**

       ( ) Industry
       ( ) Academia
       ( ) National Lab
       ( ) Other _____

2. What is your position?   _____

3. For the following question, please rank the properties of a smart distribution system in order of importance (*1 = most important*).**

_____ Incorporating distributed energy resources (DER), which include renewable energy sources (RES) and distributed storage (DS), while enabling the integration of peak-shaving technologies

_____ Adaptive and self-healing technologies for a reliable distribution system

_____ Integration of massively deployed sensors and smart meters to monitor distribution system in real-time

_____ Integration of "smart" appliances and consumer devices

_____ Active participation by consumers in demand response

_____ The ability to operate in grid-connected or islanded mode

_____ Advanced tools (including visualization, analysis, and simulation) to streamline "smart" routine operations

_____ Optimizing distributed assets to reduce losses and increase efficiency at the distribution level, while enabling new products, markets, and services for the consumer and utility/industry

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II. Incorporating Distributed Energy Resources (DER)

4. At what voltage level should DER be incorporated into the distribution system? *Please select one option.*

( ) 120 V
( ) 480 V
( ) 5 kV class
( ) 15 kV class
( ) 35 kV class
( ) Other _____

5. What "smart" qualities are desired in DER? *Please check all that apply.*

[ ] Two-way communication capabilities enabled
[ ] Decision-making capabilities
[ ] Automated adaptation based on system conditions
[ ] Digital control and measurement
[ ] Other _____

Throughout the rest of the survey, two terms will be used to describe the configuration of the local DER management system: commercially-operated distribution management system (CDMS) and local energy management system (LEMS). The **CDMS** corresponds to feeder-level management software and is operated by a commercial entity. The **LEMS** corresponds to load-level management software and is operated by the consumer.

6. How should DER be managed locally? (See Figure A.1) *Please select one option.*

( ) A: No local management
( ) B: Using a commercially-operated DMS (CDMS) integrated with utility EMS

( ) C: Using a local EMS (LEMS) integrated with utility EMS
( ) D: Using a LEMS integrated with CDMS
( ) Other _____

7. Based on the system specified in (6), how should the DER communicate? (See Figure A.2) *Please select one option.*

    ( ) A: Two-way communication with utility EMS program
    ( ) B: Two-way communication with utility EMS program and with one another
    ( ) C: Two-way communication with LEMS
    ( ) D: Two-way communication with LEMS, and with one another
    ( ) Other _____
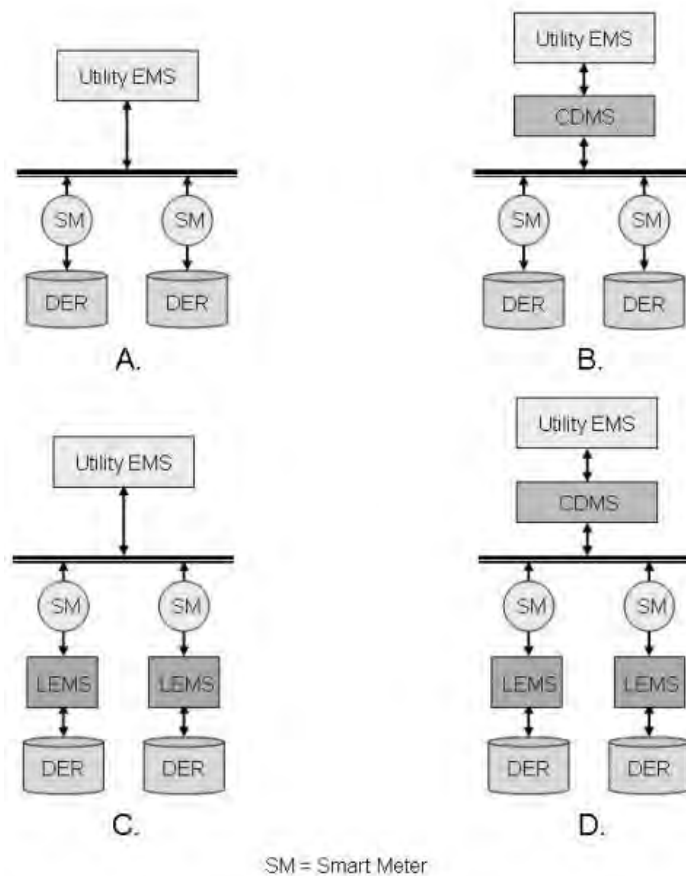
Figure A.1. Visualization of options for Question 6. Reprinted in [82] © 2009 IEEE.
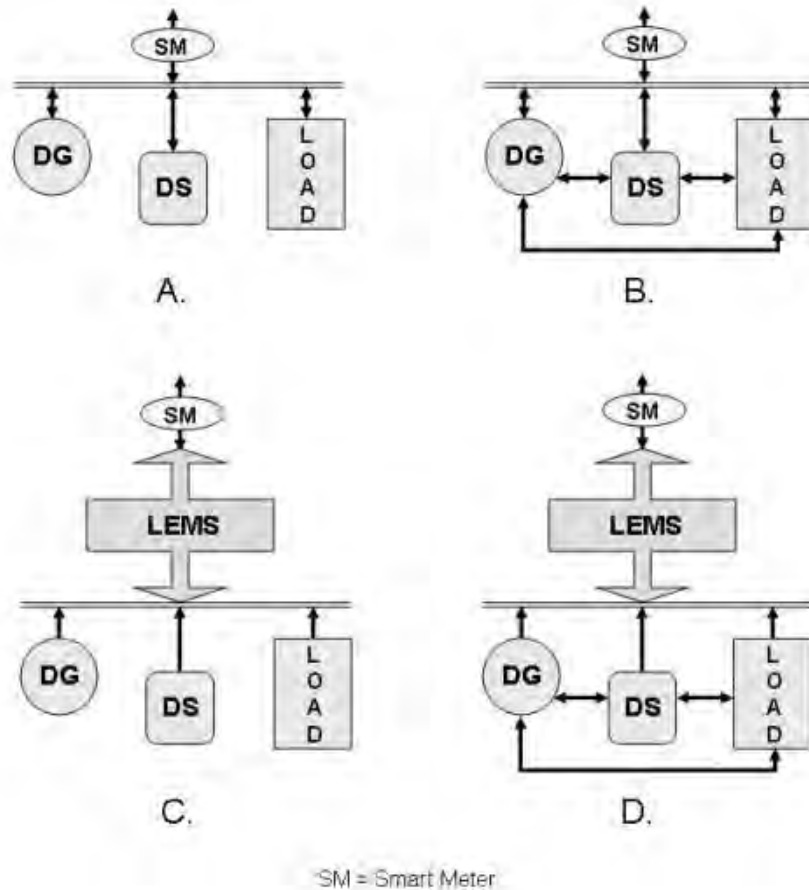
Figure A.2. Visualization for Question 7 answers. Reprinted in [82] © 2009 IEEE.

8. What percentage of the total generation should be met via RES within the next 10 years? (Most state Renewable Portfolio Standards range from 15-20% by 2030, and all include hydroelectric generation.) *Please select one option.*

    ( ) 10-19% from dispatchable sources, like geothermal and fuel cells
    ( ) 10-19% from combination of non-dispatchable and dispatchable sources
    ( ) 20-30% from dispatchable sources, like geothermal and fuel cells
    ( ) 20-30% from combination of non-dispatchable and dispatchable sources
    ( ) Other _____

9. What percentage of new DER is expected to be comprised of RES? *Please select one option.*

    ( ) Less than 25%
    ( ) 25-50%
    ( ) 50-75%
    ( ) More than 75%
    ( ) Other _____

10. What would be a desirable way of dealing with the non-dispatchability of some RES? *Please rank in order of preference, with 1 = favored method.*

    _____ Incorporate different types of distributed storage (DS)
    _____ Incorporate different types of bulk storage at the transmission level
    _____ Incorporate non-dispatchable renewables with a combination of fast-starting dispatchable
         generation sources, e.g. wind farms with natural gas-fired power plants
    _____ Monitor and predict conditions which cause intermittency to efficiently plan the system usage
    _____ Other _____

11. What renewable generation technologies could be easily incorporated into the voltage level chosen in (4)? *Please rank in order of preference, with 1 = favored method.*

    _____ Biofuels and biomass
    _____ CHP/Waste Heat
    _____ Fuel Cells
    _____ Geothermal
    _____ Landfill Gas
    _____ Municipal Waste
    _____ Photovoltaics
    _____ Solar Thermal Electric
    _____ Waste Tire
    _____ Wind
    _____ Other _____

12. Please prioritize the following "smart" functionalities that would enable the desired level of RES penetration. (*1 = highest priority*)

    _____ Predictive planning using meteorological data
    _____ Ability to store non-dispatchable energy for later use
    _____ Combination systems, where a dispatchable form is paired with a non-dispatchable form to
         maintain constant power output
    _____ Communication with EMS to know what types of renewables are generating and what levels
         they are generating at
    _____ Dynamic pricing and control options for the customer
    _____ Other _____

13. Where should DS be located? *Please select one option.*

    ( ) On the customer-side of meter
    ( ) On the utility-side of meter
    ( ) Other _____

14. How much DS would be useful (relative to the location specified in (13), in percentage of the rated load at the voltage level specified in (4) for at least 4 hours)? *Please select one option.*

( ) 1-10%
( ) 11-25%
( ) 26-50%
( ) 51-75%
( ) Above 75%
( ) Other _____

15. What percentage of non-dispatchable DER are expected to be supported by DS? *Please select one option.*

( ) Less than 25%
( ) 25-50%
( ) 50-75%
( ) More than 75%
( ) Other _____

16. What types of DS would be applicable at the voltage level specified in (4)? *Please rank in order of preference, with 1 = favored method.*

_____ Battery storage
_____ Flow batteries
_____ Flywheels
_____ UPS
_____ Super-capacitors/ Ultra-capacitors
_____ Plug-in hybrid vehicles
_____ Compressed air energy storage (CAES)
_____ Other _____

17. What "smart" functionality would enable the penetration of DS? *Please check all that apply.*

[ ] Sensors to monitor the state-of-charge in each storage unit
[ ] Automatic charge and discharge using frequency sensors – i.e. storage units absorb excess generation and then release energy when system is over-loaded
[ ] Remote control of connection/disconnection of storage units via utility EMS
[ ] Other _____

18. What is the most important benefit of DS? *(1 = most important).*

_____ Constant power output from distributed generation
_____ Ride-through capability during faults and outages
_____ Damping price spikes in market caused by unmet electricity demand
_____ Countering momentary power disturbances
_____ Energy reserves
_____ Other _____

19. Based on your answer to the previous question, what "smart" technologies best enable the perceived benefits of DS? *Please check all that apply.*

[ ] Feeder-level management of DS (via CDMS)
[ ] Load-level management of DS (via LEMS)
[ ] Disconnect switches enabled with digital control and two-way communications at DER
[ ] Storage units enabled with digital control and two-way communications
[ ] Real-time price information brought to end-user through smart metering
[ ] Other _____

20. What Smart Grid technologies enable DER usage? *Please check all that apply.*

[ ] Real-time pricing
[ ] Feeder-level management (via CDMS)
[ ] Load-level management (via LEMS)
[ ] Home area network
[ ] Utility-initiated demand response or load management program
[ ] Interconnection protocols for DER
[ ] Feeder and distribution automation
[ ] Other _____

21. Assuming "feeder and distribution automation" is a "smart" technology, what specific aspects are the most important to the integration of DER? (*1 = most important*)

_____ Microprocessor-based feeder automation with communication capability
_____ Feeder condition monitoring to improve reliability
_____ Automated adaptive relaying
_____ Feeder load transfer switch for demand response (load management)
_____ Automated feeder reconfiguration for loss reduction or overload relief
_____ Feeder fault detection and diagnostics
_____ Feeder equipment failure detection
_____ Voltage regulator with communication capability
_____ Other _____

22. How should DER usage be allowed? *Please select one option.*

( ) DER usage should be scheduled at least one day in advance
( ) DER usage may be scheduled in real-time, in addition to being scheduled in advance
( ) DER usage may occur whenever customers want to use it, in addition to being scheduled in advance
( ) DER usage may occur whenever utilities want to use it, in addition to being scheduled in advance
( ) Other _____

23. Assume DER is scheduled in advance and in real-time. Who should schedule the DER output? *Please select one option.*

( ) Utility

( ) CDMS
( ) LEMS
( ) CDMS, with approval of utility
( ) LEMS, with approval of utility
( ) Other _____

24. How should DER scheduling be limited? *Please select one option.*

( ) Contractually, e.g. there will be penalties levied against the controlling entity if the schedule is
     not maintained
( ) Unrestricted, DER may be used as desired
( ) Conditionally, utilities may approve/deny short-term DER scheduling changes
( ) Other _____

25. How often should the DER be communicating with the utility EMS (either directly or indirectly via
the CDMS or LEMS)? *Please select one option.*

( ) At least once per second
( ) At least once per minute
( ) At least once per hour
( ) At least once per day
( ) Other _____

26. How should communication take place within a "smart" distribution system? *Please check all that
apply.*

[ ] Cellular protocols
[ ] WiFi
[ ] Wireless mesh networks
[ ] Zigbee
[ ] Internet
[ ] Broadband over power lines (BPL)
[ ] Fiber-optic
[ ] Other _____

27. At what voltage level would peak-shaving technologies be incorporated into the distribution system? *Please select one option.*

      ( ) 120 V
      ( ) 480 V
      ( ) 5 kV class
      ( ) 15 kV class
      ( ) 35 kV class
      ( ) Other _____

28. When should peak-shaving occur? *Please select one option.*

      ( ) Based on dynamic pricing
      ( ) Based on time-of-use
      ( ) Other _____

29. What types of peak-shaving (in addition to DER) are the most important in a "smart" distribution system? (*1 = most important*)

      _____ Widespread use of "smart" appliances
      _____ Automatically deployed distributed assets
      _____ Residential load control, i.e. utility controls when large residential loads are run (for example, air-conditioning units or furnaces)
      _____ Commercial load control, i.e. utility controls when certain commercial loads are run
      _____ Utility-forced islanding of specific, pre-defined load areas
      _____ Other _____

30. How quickly should peak-shaving technologies engage? *Please select one option.*

      ( ) Within 10 cycles
      ( ) Within 1 minute
      ( ) Within 5 minutes
      ( ) Within 1 hour
      ( ) Peak-shaving should be scheduled before the peak times
      ( ) Other _____

III. Adaptive and Self-Healing Technologies

31. At what voltage level would adaptive and self-healing technologies be incorporated into the distribution system? *Please select one option.*

     ( ) 120 V
     ( ) 480 V
     ( ) 5 kV class
     ( ) 15 kV class
     ( ) 35 kV class
     ( ) Other _____

32. What should the philosophy of "self-healing" be? *Please rank in order of preference, with 1 = favored method.*

     _____ Preventative
     _____ Corrective
     _____ Emergency
     _____ Restorative
     _____ Other _____

33. How should the system "heal" itself? *Please select one option.*

     ( ) Automatic restoration, like the transmission system
     ( ) Actions initiated manually and supervised by the utility
     ( ) A combination of automatic restoration and utility-supervised actions
     ( ) Other _____

34. How effective should distribution-level self-healing be, with respect to ASAI? (0.999375 is the overall system average identified by reference [13]). *Please select one option.*

     ( ) 0.9999
     ( ) 0.99999
     ( ) 0.999999
     ( ) Other _____

35. What is the activation timeframe from the end of the system event for self-healing at the distribution level? *Please select one option.*

     ( ) Subcycle range
     ( ) 1 cycle range
     ( ) Several cycles range
     ( ) Other _____

36. What is the restoration timeframe for self-healing at the distribution level? *Please select one option.*

      ( ) Within subcycles, once activated
      ( ) Within 1 cycle, once activated
      ( ) Within several cycles, once activated
      ( ) Within minutes, once activated
      ( ) Other _____

37. What part of a "smart" distribution system should carry the responsibility for self-healing functions? *Please rank in order of responsibility, with 1 = most responsible.*

      _____ Operation centers
      _____ Substation automation (e.g. "smart" substations)
      _____ Feeder and distribution automation (e.g. "smart" feeders)
      _____ Other _____

38. Which of the following would add "smarts" to the "operations centers" specified in (37)? *Please rate in order of importance, with 1 = most important.*

      _____ Optimized Volt/VAR management system
      _____ Integrated outage management system and advanced metering infrastructure
      _____ Integrated outage management system and work management system
      _____ Outage damage assessment for restoration
      _____ Distribution state estimator
      _____ Fault location and analysis
      _____ Broad-area distribution monitoring system
      _____ Load management
      _____ Dynamic system topology models (software)
      _____ Other _____

39. Which of the following would add "smarts" to the "feeder and distribution automation" specified in (37)?
Please rank in order of preference, with 1 = favored method.

      _____ Smart feeder automation (microprocessor based with communication capability)
      _____ Feeder condition monitoring to improve reliability
      _____ Automated adaptive relaying
      _____ Feeder load transfer (switching for demand response / load management)
      _____ Automated feeder reconfiguration (via "smart" switching) for loss reduction or overload relief
      _____ Feeder fault detection and diagnostics
      _____ Feeder equipment failure detection (i.e. distribution-level reclosers)
      _____ Voltage regulator with communication capability
      _____ Other _____

IV. Integration of Massively Deployed Sensors and Smart Meters

40. At what voltage level would massively deployed sensors (excluding smart meters) be incorporated into the distribution system? *Please select one option.*

       ( ) 120 V
       ( ) 480 V
       ( ) 5 kV class
       ( ) 15 kV class
       ( ) 35 kV class
       ( ) Other _____

41. What types of information would the utility desire for use in a smart distribution system? *Please check all that apply.*

       [ ] Monitor direction and amounts of power flow
       [ ] Monitor locations and usage patterns of DER
       [ ] Notification of when and how much DER are energizing the system
       [ ] Monitor system impedance to ensure accurate protection settings
       [ ] Other _____

42. What is your definition of "real-time" with respect to massively deployed sensors and smart metering? *Please select one option.*

       ( ) Updates at least once per day
       ( ) Updates at least once per hour
       ( ) Updates at least once per minute
       ( ) Updates at least once per second
       ( ) Updates at least once per 1/60 of a second
       ( ) Other _____

43. What types of sensors should have an increased presence in distribution level monitoring? *Please rank in order of preference, with 1 = favored technology.*

_____ Giant magnetoresistance (GMR)
_____ Optical (e.g. Faraday effect)
_____ Hall effect
_____ Satellite
_____ Mechanical
_____ Chemical
_____ Video
_____ Phasor measurement units (PMU)
_____ Digital sensors with incorporated intelligence
_____ Thermal
_____ Shock
_____ Photo
_____ Other _____

44. Which Smart Grid applications do you see from increased incorporation of massively deployed sensors? *Please rank in order of preference, with 1 = favored application.*

_____ Alarm-processing algorithms, triggered based on system data gleaned from massively deployed sensors, to take action in non-critical situations
_____ Apply ideas from wide-area measurement systems (WAMS) and wide-area control systems (WACS) to create a broad-area distribution control system, which could control distribution system components to optimize certain values, such as reactive power
_____ Home automation network interfaced with utility Smart Grid system
_____ Applying intelligent network feedbacks to create a new market system
_____ Upgrade and replace existing electro-mechanical control system with microprocessor-based control system, enabling communication
_____ Dynamic line rating to improve system reliability
_____ Flexible power flow control
_____ Substation automation
_____ Feeder and distribution automation
_____ Automated distribution system restoration
_____ Other _____

45. What "smart" functionality should the massively deployed sensors possess? *Please check all that apply.*

[ ] One-way communications
[ ] Two-way meshed communications
[ ] Control algorithms, such that the sensor has an actuator component and can react to system measurements without manager input (e.g. sensor/actuator combination)
[ ] Other _____

46. How should the smart meter act? *Please select one option.*

       ( ) As a communication link
       ( ) As a communication link and as a local control system
       ( ) Other _____

47. What functionality should an ideal smart meter possess? *Please check all that apply.*

       [ ] Ability to measure bi-directional power flow
       [ ] Two-way communication with utility
       [ ] Two-way communication with other devices, such as DER or CDMS/LEMS
       [ ] Control of DER
       [ ] Interpret system economic information, such as the real-time price
       [ ] Schedule and bid for system activity – use of distributed energy resources, ancillary services
       [ ] On-demand reads
       [ ] Scheduled reads
       [ ] Real-time reads
       [ ] Current and voltage profiling
       [ ] Demand, load, and generation profiling
       [ ] Tamper detection
       [ ] Power quality monitoring and alarms
       [ ] Outage and restoration alarms
       [ ] Event logging
       [ ] Store and download time-of-use schedules
       [ ] Time synchronization
       [ ] Automatic registration
       [ ] Other _____

V. Integration of "Smart" Appliances and Consumer Devices

48. What types of "smart" appliances are the most useful to you? *Please select one option.*

       ( ) Thermal devices, including dual-mode CHP (e.g. refrigerator)
       ( ) Programmable devices, i.e. the user programs the device schedule
       ( ) Smart-circuit devices, where the "smartness" is in the circuit with learning algorithms (e.g. a
          device that would be off until it was "pinged")
       ( ) Other _____

49. What "smart" functionality should "smart" appliances and consumer devices possess? *Please check all that apply.*

       [ ] Two-way communication
       [ ] Control algorithms, set using the smart meter
       [ ] Other _____

50. Where should the control system for smart appliances be located? *Please select one option.*

       ( ) Programmable controls on the device
       ( ) Local EMS (LEMS)
       ( ) Smart metering
       ( ) Demand response/ load management program
       ( ) Other _____

VI. Active Participation by Consumers in Demand Response

51. What "smart" functions help consumers actively participate in demand response? *Please rank in order of preference, with 1 = favored function.*

       _____ Dynamic pricing
       _____ Direct load control or load cycling by utilities
       _____ Contractual obligations to load curtailment and/or DER deployment
       _____ Price-responsive demand bidding
       _____ Other _____

52. Which type of dynamic pricing is preferred for your definition of a "smart" system? *Please select one option.*

       ( ) Real-time pricing
       ( ) Interval pricing
       ( ) Time-of-use pricing
       ( ) Critical peak pricing
       ( ) Other _____

53. How much control is the utility willing to give the consumer with respect to the point of common coupling (PCC)? *Please select one option.*

       ( ) a. **No control at the meter**, the customer controls small loads (< 3 kVA) and the utility controls everything else, including "smart" appliances.
       ( ) b. **Very limited control at the meter**, the customer controls loads, including smart appliances, and the utility controls DER.
       ( ) c. **Limited control at the meter**: the customer controls real power supplied by the DER, loads, energy demand, automated controls for smart appliances, DER, demand response, and market participation through supply of ancillary services.
       ( ) d. **Total control at the meter** of utility-approved installations, the customer controls the ability to island, and everything in (c).
       ( ) Other _____

54. With respect to the previous question, should the utility have override control? *Please select one option.*

      ( ) No
      ( ) Yes, for all cases
      ( ) Yes, but only for cases (c) and (d)
      ( ) Yes, but only for case (d)
      ( ) Other _____

55. What "smart" technologies would enable demand response? *Please check all that apply.*

      [ ] Advanced metering infrastructure
      [ ] Programmable, communicating consumer devices or "smart" appliances
      [ ] Local EMS (LEMS) software, to enable consumers to self-manage
      [ ] Building/facility energy management system interfaced with market pricing signals
      [ ] "Smart" appliances interfaced with utility management system
      [ ] Distribution state estimator
      [ ] Other _____

56. What is a useful time-frame for automated demand response? *Please select one option.*

      ( ) Within subcycles
      ( ) Within 1 cycle
      ( ) Within several cycles
      ( ) Within minutes
      ( ) Within 1 hour
      ( ) Other _____

VII. Ability to Operate in Grid-Connected or Islanded Mode

57. At what voltage level would the ability to operate as an island be incorporated into the distribution system? *Please select one option.*

      ( ) 120 V
      ( ) 480 V
      ( ) 5 kV class
      ( ) 15 kV class
      ( ) 35 kV class
      ( ) Other _____

58. What "smart" functionality should a system with islanding potential have? *Please check all that apply.*

       [ ] Control systems for local regulation of voltage, real power balance and reactive power balance
       [ ] Power flow monitoring within island
       [ ] Utility ability to identify islands, i.e. a communication link between the island and the utility
       [ ] Fault location and post-automated response
       [ ] Automatic switching between islanded and grid-connected modes
       [ ] Anti-islanding mechanisms under purview of utility
       [ ] Other _____

59. How should a system with islanding potential switch to an islanded system? *Please select one option.*

       ( ) Automatically by commercially-operated DMS (CDMS)
       ( ) Automatically by local EMS (LEMS)
       ( ) Automatically by CDMS, with utility override
       ( ) Automatically by LEMS, with utility override
       ( ) Automatically by utility
       ( ) Other _____

60. What "smart" technologies would allow the ability to switch between grid-connected or islanded mode? *Please check all that apply.*

       [ ] Smart interconnection switches with communications capability
       [ ] Smart reclosers with communications capability
       [ ] Implement controls for grid-like behavior (i.e. measuring frequency and voltage droop to control real and reactive power outputs)
       [ ] Governor with two-way communications
       [ ] CDMS/LEMS enabled to manage island system
       [ ] Other _____

VIII. Advanced Tools to Streamline "Smart" Routine Operations

61. What functionality might a "smart" distribution system management program have? *Please check all that apply.*

[ ] Automatic reporting to utility of smart meter measurements with time stamp, and using data to plan and/or predict future usage
[ ] Price predictions of energy to plan future usage
[ ] Optimize portfolio of loads, DG, and DS for use in load flow studies
[ ] Create back-up arrangements if specific components were to fail or be inactive (i.e. if solar panels unusable due to weather; if islanded from grid; if storage unit fails)
[ ] Customer-driven – i.e. customer "designs" personal system and receives utility approval for grid connection
[ ] Utility-driven – i.e. utility decides the amount and mix of DER that a customer is allowed
[ ] Other _____

62. What data storage amount would be desirable in a utility-driven distribution management program? *Please select one option.*

( ) All available data ("Critical", "Useful", and "Other")
( ) Critical" and "Useful" data
( ) Just "Critical" data
( ) No data storage
( ) Other _____

63. Where should the data storage server (with back-up) be located? *Please select one option.*

( ) At the location of collection, on the utility-side of the smart-meter
( ) At the location of collection, on the customer-side of the smart-meter
( ) At data-collection centers distributed throughout the system (i.e. a substation)
( ) At the utility center of operations
( ) Other _____

IX. Optimizing Distribution Assets, with New Products, Services, and Markets

64. What product philosophy will contribute to the adoption of the smart distribution system? *Please rank in order of preference, with 1 = favored philosophy.*

_____ Easy upgrades
_____ Plug-and-play methodology
_____ Standardized services
_____ Regulatory adjustment
_____ Government policies and subsidies
_____ Other _____

65. What new services would be opened up by the adoption of a "smart" distribution system? *Please check all that apply.*

       [ ] Small-scale energy management companies
       [ ] Planning services, for both system design and usage planning
       [ ] Power quality on demand
       [ ] Asset deployment and management
       [ ] Smart grid–tailored devices
       [ ] Software tools for commercially-operated DMS (CDMS)
       [ ] Software tools for local EMS (LEMS)
       [ ] Other _____

66. What new markets would be opened to utilities by the adoption of a "smart" distribution system? *Please check all that apply.*

       [ ] Managing energy for the consumer
       [ ] Planning services, for both system design and usage planning
       [ ] Power quality on demand
       [ ] Ancillary services
       [ ] Smart grid–tailored devices
       [ ] Other _____

67. What "smart" technologies are the most important for enabling new products, services, and markets? *Please rank in order of preference, with 1 = favored technology.*

       _____ Real-time or time-of-use pricing options design and research
       _____ Applying intelligent network feedbacks and consumer responses to make a new market system
       _____ Demand response/ load management program
       _____ Smart appliances that interface with utility Smart Grid system
       _____ Smart metering infrastructure
       _____ Other _____

68. What other distribution system changes would enable new products, services, and markets? *Please rank in order of preference, with 1 = favored changes.*

       _____ Meshed/networked distribution
       _____ Custom power devices
       _____ DER developments
       _____ Combined heat and power (CHP)
       _____ Other _____

69. What areas in the distribution system would need further optimization to ensure successful operation of a "smart" distribution system? *Please check all that apply.*

     [ ] Networked connections between feeders
     [ ] Networked connections among all assets at the distribution level
     [ ] Devices with 2-way communication for reporting and control, whether by the utility or the CDMS/LEMS
     [ ] Other _____

70. What "smart" technologies would help to optimize asset utilization and efficient operation? *Please check all that apply.*

     [ ] Condition-based monitoring and maintenance
     [ ] Computerized maintenance management
     [ ] Advanced asset management software
     [ ] Advanced outage avoidance and management
     [ ] Dynamic distribution line ratings
     [ ] Transformer load management
     [ ] Grid simulator and modeler, tailored to the distribution level
     [ ] Flexible power flow control at distribution level
     [ ] Other _____

X. Additional Comments

71. Please submit any final comments.

_____
_____
_____
_____
_____

XI. Thank You!

Thank you for taking our survey. Your response is very important to us.

XII. References

Note from the author: The references used in the preparation of this survey have been discussed in the Introduction, Section 1.4.1, "Compendium of smart grid and smart distribution system efforts", and have been omitted in the interest of space.

APPENDIX II

CONTENTS OF THE ELECTRONIC APPENDIX FOR PART 1

The DVD included with this report contains an electronic version of the survey text included in Appendix I, the data for the survey responses, and the Matlab code used to graph the responses. Additionally, the DVD includes the code for the custom Matlab functions created for the analysis of the test systems described in Chapter 4 and the PowerWorld files for the test system simulations. Required programs are Matlab R2008a (file types *.m* and *.fig*), PowerWorld Simulator 14 (file types *.pwb* and *.pwd*), and Adobe Acrobat Reader (file types *.pdf*). To run the code, Matlab is required, but to solely view the code contents of any *.m* file, a text editor will suffice. A text editor, such as Microsoft Notepad, is also required to view *.txt* files and *.aux* files. Additionally, there are some image files in the outputs provided and they are *.fig*, which must be opened with Matlab, and *.jpg*, which should be able to be opened in any common image editor, such as Adobe Photoshop or Microsoft Paint.

The contents are arranged into three file folders which contain code, simulation outputs, survey outputs, and other reference material considered to be of some interest to the reader. The three folders are 'SmartDistributionSurvey', '3FDR_Simulations', and 'RBTS_Simulations'. The contents of these folders will now be outlined. This information is contained electronically in the 'README' files for each folder, which are *.txt* files.

Contents of 'SmartDistributionSurvey'

Contents of this folder are in three types: *.m* (code), *.txt* (data), and *.pdf* (reference material). The folder contents are outline below by type.

% *Folder*

%   Outputs ... this folder contains the outputs of the survey in .txt format. Each question has

%   its own file of responses. The numbering begins with question 1 as the first question

%   in the section entitled 'Incorporating Distributed Energy Resources (DER)'. These are

%   the outputs from September.

% *Reference Material*

%   SurveyResults_Oct09 ... the survey results by question from October 2009, contains the

%   survey question, responses, and relevant information.

%   SurveyText ... a document containing the survey text for each question. As a warning, the

%   question numbering in this document does not match the question numbering for

%   the code and output files.

% Code

%   IntroQs ... contains the code to analyze the introductory questions

%   Section1 ... contains the code to analyze the questions from the section titled 'Incorporating

%   Distributed Energy Resources (DER)'

%   Section2 ... contains the code to analyze the questions from the section titled 'Adaptive and

%   Self-Healing Technologies'

%   Section3 ... contains the code to analyze the questions from the section titled 'Integration of

%   Massively Deployed Sensors and Smart Meters'

%   Section4 ... contains the code to analyze the questions from the section titled 'Integration of

%   "Smart" Appliances and Consumer Devices'

%   Section5 ... contains the code to analyze the questions from the section titled 'Active

%   Participation by Consumers in Demand Response'

%   Section6 ... contains the code to analyze the questions from the section titled 'Ability to

%   Operate in Grid-Connected or Islanded Mode'

%   Section7 ... contains the code to analyze the questions from the section titled 'Advanced

%   Tools to Streamline "Smart" Routine Operations'

%   Section8 ... contains the code to analyze the questions from the section titled 'Optimizing

%   Distribution Assets, with New Products, Services, and Markets'

% Explanation of code:

%   Each section of questions has its own section of code to read and "analyze" the responses

%   for each question. All code reads question information from a .txt file, stored in "/Outputs".

%   The naming scheme on the .txt files is "Qn.txt", where 'n' is the question number (should be

%   01, 02, etc for numbers less than 10). At the beginning of each section, all existing

%   variables and outputs are cleared. If you would like to have all that information available

%   while looking at another section, suppress the commands.

%   There are three types of questions in the code: multi-select, ranking, and multiple choice.

%   Each has a different arrangement, based on how the .txt file has the information stored.

%   Each percentage and average rank is calculated for the number of actual responses, this

%   ensures that the percentages add up to 100%, since not all of the survey questions are

%   required.

% List of naming conventions used in the code:

%   n ... Question number

%   Other_n ... set to T/F based on whether or not there are "other" answers

%   cellsn ... array of info cells related to the question, extracted from the text file, Q0n.txt

%   IDn ... the respondent IDs for the responses

%   answersn ... the relevant information to be extracted

%   An, Bn ... may either be a scalar or an array. If it is a scalar, then it reflects the number of

%   times that answer (A, B, etc) appeared; if it is a scalar, then it reflects a list of the

%   ranks that letter answer has been given.

%   an, bn ... average rank (sum(An)/(# of non-zero answers))

%   ranksn ... a vector of the average ranks for the answers

%   Non ... number of empty responses

%   Otn ... number of "Other" responses

%   othersn ... list of the "other" responses

%   numn ... number of non-empty responses

%   resultsn ... array of percentage results for the question

%   checkn ... dummy variable for multi-select questions

%   datan ... soley defined for ranking -type questions, stores the rankings in row 1 and

%   answersn in remaining rows. Normally only access row 1.

%   colsn ... a list of the non-zero ranks for statistical analysis

%   devn ... the standard deviations of the ranks

Contents of '3FDR_Simulations'

This folder is broken down into three subfolders including the simulations and codes for the sequential feeder method with two objectives and the feeder method with three objectives, as well as the multi-objective optimization method, which includes objective functions for both two and three objectives.

% HeuristicTechnique contents

%   10_bus_rep2.pwb(.pwd) ... PowerWorld file and display file for the 3FDR test system

% branch_EX() ... a function to extract the branch information
%   I: A, output_branch, branchflds
%   O: branch_imp, lines, xfrmrs, reqdinf
% bus_EX()   ... a function to extract the bus information
%   I: A, output_bus, busflds
%   O: businfo, reqdinf
% DeviceListDisp() ... a function to extract bus, branch, gen & load info
%   I: A, prnt (T/F value to print results)
%   O: basic bus, branch, gen & load info
% editmode() ... a function to enter SimAuto "Edit" mode
%   I: A
%   O: none
% eens()   ... a function to determine the energy not supplied using an estimated outage time
%   (found from the given ASAI)
%   I: A, T, genflds, output_gen, slack_buses
%   O: rel
% genEX()   ... a function to extract the system generator information
%   I: A, genflds, output_gen, slack_buses
%   O: slackgen, regen, reqdinf
% getinf()   ... a function to retrieve case information from SimAuto
%   I: A, prnt
%   O: slackinf
% resetslack()... a function to reset buses that are no longer slack to
%   zero output
%   I: A, reqd_gen, slack_buses, reqdGENfields
%   O: none
% runmode()   ... a function to enter SimAuto "Run" mode
%   I: A
%   O: none
% RunSFM   ... the purpose of this file is to use SimAuto to reproduce the results found in
%   PowerWorld and published in the T&D submission. The PowerWorld results were
%   found 'by hand' and these results should be heuristically 'automated'.
% SFM_Output.txt ... the output of the heuristic technique applied to the 3FDR test system
% violations()... a function to determine whether there are any loading or voltage violations

%   I: bus soln info, line loading percent

%   O: busV & branchV - T/F values whether violations present

% HeuristicTechnique_3O contents

% 10_bus_rep2.pwb(.pwd) ... PowerWorld file and display file for the 3FDR test system

% branch_EX() ... a function to extract the branch information

%   I: A, output_branch, branchflds

%   O: branch_imp, lines, xfrmrs, reqdinf

% bus_EX()   ... a function to extract the bus information

%   I: A, output_bus, busflds

%   O: businfo, reqdinf

% DeviceListDisp() ... a function to extract bus, branch, gen & load info

%   I: A, prnt (T/F value to print results)

%   O: basic bus, branch, gen & load info

% editmode() ... a function to enter SimAuto "Edit" mode

%   I: A

%   O: none

% eens()   ... a function to determine the energy not supplied using an estimated outage time

%   (found from the given ASAI)

%   I: A, T, genflds, output_gen, slack_buses

%   O: rel

% genEX()   ... a function to extract the system generator information

%   I: A, genflds, output_gen, slack_buses

%   O: slackgen, regen, reqdinf

% getinf()   ... a function to retrieve case information from SimAuto

%   I: A, prnt

%   O: slackinf

% Outputs   ... a folder containing the outputs of the three objective optimization using the

%   heuristic technique in .fig (a Matlab graph) form, as well as .jpg

% resetslack()... a function to reset buses that are no longer slack to zero output

%   I: A, reqd_gen, slack_buses, reqdGENfields

%   O: none

% runmode() ... a function to enter SimAuto "Run" mode

%   I: A

%   O: none
%   RunSFM_3O   ... the purpose of this file is to apply the heuristic technique to the 3FDR test
%   system considering the three objectives of cost, reliability, and losses
%   violations()... a function to determine whether there are any loading or voltage violations
%   I: bus soln info, line loading percent
%   O: busV & branchV - T/F values whether violations present

% MOGA contents
%   10_bus_rep2.pwb(.pwd) ... PowerWorld file and display file for the 3FDR test system
%
%   branchEXreduced() ... a function to extract the branch information
%   I: A, output_branch, reqdBRANCHfield
%   O: chng_branch
%   BranchFormat() ... a function to arrange the branch information in a form recognized by
%   SimAuto as branch data
%   I: chng_branch
%   O: valuelist, num_elems
%   busEXreduced() ... a function to extract the bus information
%   I: A, output_bus, busflds
%   O: reqd_bus
%   DevListDispReduced() ... a function to extract the branch and bus device information from
%   the open file
%   I: A, prnt
%   O: output_branch, output_gen
%   editmode()   ... a function to enter the edit mode in SimAuto
%   I: A
%   O: none
%   EENSreduced ... a function to calculate the reliability
%   I: A, T, output_gen, reqdGENfields, slack buses
%   O: rel
%   flatstart() ... a function to reset the system slack buses
%   I: A
%   O: none
%   genEXreduced() ... a function to extract the generation information

%   I: A, output_gen, reqdGENfields, slack_buses

%   O: slackgen, reqd_gen

%   getinf()   ... a function to print system information for the open case, as well as finding the

%   active slack buses

%   I: A, prnt

%   O: slackinf

%   losses()   ... a function to calculate the system losses

%   I: A, output_branch, LossBranchFld

%   O: losses

%   objeval   ... the function to evaluate the fitness function values for the multiobjective genetic

%   algorithm for two objectives, cost and reliability.

%   I: x

%   O: [cost; reliability]

%   objeval_3f   ... the function to evaluate the fitness function values for the multiobjective

%   genetic algorithm for three objectives: cost, reliability, and losses.

%   I: x

%   O: [cost; reliability; losses]

%   resetslack() ... a function to reset the slack buses to 1 pu at an angle of 0 deg.

%   I: A

%   O: none

%   runmode()   ... a function to enter the run mode

%   I: A

%   O: none

%   RunMOGA.m   ... the "run" file to evaluate the multi-objective optimization using the Matlab

%   function, gamultiobj(),for the 3FDR test system

%   TestOutputs   ... a folder containing the simulation outputs for both the two-objective

%   evaluation (contained in subfolder 'TwoObjectives') and the three-objective

%   evaluation (contained in subfolder 'ThreeObjectives')

Contents of 'RBTS_Simulations'

      This folder contains three codes for running optimizations on the RBTS Bus 3 distribution system. It contains all the subfunctions called by those codes, as well as selected output from trial runs. This folder also contains the PowerWorld files used in the simulations of the RBTS system. PowerWorld binary (PWB) files are used in Matlab by SimAuto. PowerWorld Display (PWD) files are used to display

the system in PowerWorld and there is not a display file for many of the PWBs because the simulations were completed solely in Matlab.

% Preparation file

%   PrepFile.m ... used for component sizing and creating the .aux file of possible connections

%   between buses for the feeder addition problem

% Optimization files

%   RunSFM.m ... used to run the "Sequential Feeder Method", a heuristic optimization

%   technique incorporating lexicographic ordering for the objectives of cost and

%   reliability. The output is printed to the command line.

%   RunSFM_alt.m ... used to run the "modified Sequential Feeder Method", a heuristic

%   optimization technique incorporating lexicographic ordering for the objectives of

%   cost and reliability. This method differs from the unmodified sequential feeder

%   method in that it begins by closing all normally open lines in the system. The output %

is printed to the command line.

%   RunMOGA.m ... used to specify the settings and the objective function for the multiobjective

%   optimization of cost and reliablity using a genetic algorithm function from Matlab,

%   gamultiobj(). Then, the output of the algorithm is printed to the command line.

% Subfunctions

%   ASU()   ... a function to extract information programmed at Arizona State University for

%   the RBTS Bus 3 Distribution System

%   I: prnt

%   O: L_line, LP, Peak_Avg, fdr_lens

%   branchEX() ... a function to extract the branch information

%   I: A, output_branch, branchflds

%   O: branch_imp, lines, xfrmrs, reqdinf

%   branchEXreduced() ... a function to extract the branch information

%   I: A, output_branch, branchflds

%   O: chng_branch

%   BranchFormat() ... a function to arrange the branch information into a

%   the format recognized by SimAuto

%   I: chng_branch

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%   O: valuelist, num_elems
%   busEX()   ... a function to extract the bus information
%   I: A, output_bus, busflds
%   O: businfo, reqdinf
%   busEXreduced() ... a function to extract the bus information
%   I: A, output_bus, busflds
%   O: reqdinf
%   CreateAux()... a function to create the .aux file of the possible connections between feeders in
%   the RBTS Bus 3 distribution system
%   I: writefile, feeders, fdr_lens, d, bus_names, lims,
%   r_per_km, x_per_km, cost_inc
%   O: cost, (writefile.aux in current directory)
%   DeviceListDisp() ... a function to extract bus, branch, gen & load info
%   I: A, prnt (T/F value to print results)
%   O: basic bus, branch, gen & load info
%   DevListDispReduced() ... a function to extract bus, branch, gen & load info
%   I: A, prnt
%   O: output_branch, output_gen, output_bus
%   editmode() ... a function to enter SimAuto "Edit" mode
%   I: A
%   O: none
%   eens()   ... a function to determine the energy not supplied using an estimated outage time
%   (found from the given ASAI)
%
%   I: A, T, genflds, output_gen, slack_buses
%   O: rel
%   EENSreduced()   ... a function to determine the energy not supplied using an estimated outage %
time (found from the given ASAI)
%   I: A, T, genflds, output_gen, slack_buses
%   O: rel
%   exfunc ... a function to switch data types before writing information to the .aux file
%   flatstart()   ... a function to reset the system generators to the
%   flat start condition of 1 pu at an angle of 0 deg.
%   I: A

```
%              O: none
%  genEX()     ... a function to get the slack bus generation, called within eens()
%              I: A, output_gen, genflds, slack_buses
%              O: slackgen, regen, reqdinf
%  genEXreduced() ... a function to extract the information about system generators and slack
%              buses
%              I: A, output_gen, reqdGENfields, array of slack buses
%              O: slackgen, reqd_gen
%  getinf()    ... a function to retrieve case information from SimAuto
%              I: A, prnt
%              O: slackinf
%  loading()   ... a function to extract the branch loading information
%              I: A, output_branch, branchflds
%              O: maxpercent
%  LP_line()   ... a function that links the load points to the line that serves them. Output in
%              format [load point; line serving]
%              I: none
%              O: L_line
%  penalty()   ... a function to create the penalty scaling variable for line and voltage constraint
%              violations
%              I: maxpercent, puvolt
%              O: p_scale
%  RBTS_lines() ... a function establishing the physical connection between buses in the system
%              I: N_B, N_LINES
%              O: LINE, y
%  RBTSobjeval() ... a function is to evaluate the cost and reliability for the multi-objective GA
%              process.
%              I: x (an individual from the GA)
%              O: f (the objective function values [cost; rel]
%  resetslack()... a function to reset buses that are no longer slack to zero output
%              I: A, reqd_gen, slack_buses, reqdGENfields
%              O: none
%  runmode()   ... a function to enter SimAuto "Run" mode
%              I: A
```

```
%          O: none
%  v_level()   ... a function to extract the bus voltage information
%          I: A, output_bus, busflds
%          O: puvolt
%  violations()... a function to determine whether there are any loading or voltage violations
%          I: bus soln info, line loading percent
%          O: busV & branchV - T/F values whether violations present


% PowerWorld files
%  RBTS_Bus3Dist.pwb (.pwd) - power world simulator file and display file of the base system.
%          This has one DG.
%  RBTS_Bus3DistFull.pwb    - power world simulator file of the base system, plus the possible
%          connection lines as open lines. This has one DG.
%  RBTS_Bus3Dist_2dg.pwb    - power world simulator file of the base system. This has two
%          DGs.
%  RBTS_Bus3DistFull_2dg.pwb- power world simulator file of the base system, plus the
%          possible connection lines as open lines. This has two DGs.
%   RBTS_Bus3Dist_3dg.pwb     - power world simulator file of the base system. This has three %
DGs.
%  RBTS_Bus3DistFull_3dg.pwb- power world simulator file of the base system, plus the
%          possible connection lines as open lines. This has three DGs.
%  RBTS_Bus3Dist_4dg.pwb    - power world simulator file of the base system. This has four
%          DGs.


% Folders
%  MOGA_output ... contains subfolders for case I, II, and III and each folder has the outputs for
%          each of the cases
%  SFM_output  ... contains subfolders for case I, II, and III and each folder has the outputs for
%          each of the cases for both the unmodified and modified sequential feeder approach
```