Electricity and Conflict: An Evaluation of Distributed Co-Generation as an Economic and Reliable Solution

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Abstract:

The record of the conflicts in Bosnia-Herzegovina and Lebanon indicates the need to consider deliberate attacks when planning electric power systems in areas with the potential for conflict. It is hypothesized that a distributed system based primarily upon natural gas cogeneration facilities will be more economical and robust. A previously developed green-field system optimization model found that distributed cogeneration using internal combustion natural gas fired engines was the lowest cost option to supply both electricity and heat, resulting in substantial savings. This analysis will be augmented with a robustness engineering analysis. To determine the reliability advantages of distributed generation, a Monte Carlo simulation was developed to conduct generating capacity adequacy assessments. The model was used to determine the Loss of Load Expectation (hr/yr.) and Loss of Energy Expectation (MWh/yr.) for both a standard test system (consisting of 32 generating units) and for a system consisting of 284 identical 12 MW units. In order to simulate the effects of conflict on the system, the mean time to repair for each unit was increased and the reliability indices re-calculated. The results show that the system consisting of a large number of smaller units is up to 5 times less sensitive to changes in the MTTR.

Keywords: electric power, distributed cogeneration, survivability, conflict

1. Introduction

Electric power systems must sometimes be developed and maintained under adverse conditions. In this research, we examine the difficulties faced in electric power systems development in areas of political instability. The task of the electricity planner in such cases is complicated by the fact that electric power systems are obvious targets when violent conflict occurs. If improvement of energy services is to play a role in economic development in such areas, then it is necessary to plan ahead to mitigate against potential damage to the electric power sector should violent conflict erupt. The purpose of this research is to determine whether electric power systems that include significant distributed generation are more robust under adverse conditions and how the relative economics of centralized versus distributed generation change when the survivability of the system is introduced as an important attribute of the system. It is hoped, however, that the methodologies developed in analyzing this problem will be more generally applicable, in particular to other situations in which adverse conditions, whether physical or economic, result in constrained electricity capacity.

The methodology will consist of an engineering analysis of the robustness of various electric power system delivery configurations under different stresses to the system. This engineering analysis will be coupled with an economic analysis that will include robustness of the system as a parameter and compare the economics of different types of systems depending upon the need for robustness. It is hypothesized that a distributed system based primarily upon natural gas cogeneration facilities will be more robust under these adverse conditions. Distributed generation, by placing a much larger number of generators close to the demand load, would mitigate against two problems with centralized electricity generation.[1] First, there would be less reliance on a small number of large generators so that when a generator is damaged, a much smaller proportion of the generating capacity is unavailable. Second, even if large generators can be defended, the transmission and distribution system largely cannot, and therefore, by reducing reliance on the T&D portion of the electric grid, distributed generation would result in a continuation of some electricity service.

If the distributed generation is based upon natural gas fired generators, there will continue to be a delivery network upon which the electricity system is based, and that delivery system could be potentially vulnerable. However, natural gas transmission and distribution systems are generally underground and therefore better protected electrical transmission and distribution lines and also do not have the real-time operational problems that electric power grids do when there is a disturbance to the system. The overall robustness of the system may be further enhanced through the use of flexible fueling of the distributed generation system and/or local fuel storage in order to mitigate against fuel pipeline attacks.

The idea of using distributed generation to overcome the vulnerabilities of centralized generation has been put forth in the past. However, as far as we have been able to determine, a rigorous quantitative analysis has not been conducted to determine the exact impacts of distributed generation on reliability in times of conflict. The available literature has focused primarily upon the United States and upon either acts of sabotage or a major conflict with the Soviet Union (at the time of the writing, which was in the eighties). (OTA 1990, Clark and Page 1981) Furthermore, the economies of scale of centralized generation, the use of coal as the dominant fuel for electricity generation and issues related to the convenience to the

[1] There is no general agreed upon definition of “distributed generation.” Willis and Scott consider units ranging from 10 to 10,000 kW to be distributed (Willis and Scott 2000, p.1). In our study of natural gas fired distributed generation we have considered 1,000 kW (1 MW) to be the upper limit on what is considered “distributed generation” and generation between 1 and 50 MW to be intermediate between distributed and centralized.

consumer of having their own generating unit would seem to have precluded the implementation of this solution in the past. Changes in the relative economics of centralized versus distributed generation, the increasing use of natural gas as a fuel which is much more convenient for the user, and improved control technologies, result in the possibility of now reconsidering the use of distributed generation for this purpose.

Careful consideration will have to be made as the research progresses between cases where pre-existing infrastructure is limited and those cases where a change to distributed generation involves a major transition of the electricity system. These two situations will have different technical and economic characteristics that could affect the results of the economic analysis. In general, retrofitting can be expensive and the issue of sunk capital could become important. However, in many cases this may not be an issue. Of the 27 major armed conflicts in 1999, eleven occurred in Africa and nine occurred in Asia (SIPRI 2000). In the case of Asia, the non-industrialized Asian countries are expected to greatly increase their use of natural gas over the next two decades. The Energy Information Administration projects average increases of approximately five percent per year for the developing regions of Asia (not including China, India, and South Korea, which are projected to have increases of 6.8 to 11.2 percent per year). Such large increases will have to be accompanied by development of infrastructure for natural gas delivery. Increases in electricity consumption in the developing economies of Asia is also expected to be high, increasing by an average of five percent per year.

As for Africa, increases in natural gas consumption are expected to be modest. However, it should be noted that this is due to economic development problems, in part linked to political instabilities. As it stands, power generation is the largest component of natural gas usage in Africa, accounting for approximately 40% of demand. In terms of the electricity sector, Africa lags behind the rest of the world in terms of access to electricity. In the next two decades, electricity consumption in Africa is expected to grow at 3.7% per year. This increase in consumption will in part be due to increasing access to the electricity grid. (EIA 2000)

This paper will provide a brief background on the issue of targeting of electric power systems in war, the engineering and economic analysis proposed to address this issue, and some of the preliminary results of that analysis.

2. Historical Cases

A recent example of the deliberate targeting of electric power infrastructure of a combatant can be found in the NATO bombing of Yugoslavia in 1999. During the bombing campaign electric power transformers were destroyed and metal shavings were used to short-circuit the transmission grid.[2] However, the targeting of electric power systems during conflict is not a new phenomenon. For example, German electric power plants were targeted late during World War II in an apparently successful effort to hamper war production efforts (Clark and Page 1981, pp. 49-54).

An overview of two recent cases provides a perspective on the nature of the problem and impacts of destruction of electric power systems. The wars in both Bosnia-Herzegovina and Lebanon had significant impacts on the operation of their respective electric power systems. Information on conflicts in these countries clearly indicates that a relatively small amount of damage can result in severe and long-lasting disruptions to the system.

[2] See for example, Gordon 1999.

2.1. Bosnia[3]

Prior to the war in Bosnia-Herzegovina in the early nineties, electricity consumption in Bosnia was approximately 12,000 GWh (1990). Demand was met through domestic power plants, mainly a combination of hydropower and thermal plants. Thirteen hydropower plants were in operation with an approximate capacity of 2,000 MW. The thermal plants were fueled with domestically mined brown coal and lignite and had a capacity of approximately 2,000 MW as well. Total electricity production in 1990 amounted to nearly 13,000 GWh with the hydropower plants supplying a little less than 7,000 GWh and the thermal plants a little more than 9,000 GWh.

By 1996 the electricity production situation in Bosnia had dramatically changed. Over 56% of the total generating capacity in the Bosnian Federation was unavailable due to direct damage.[4] Of the remaining capacity, a portion was also unavailable due to either a lack of fuel (the mining sector in Bosnia-Herzegovina was also impacted by the war) or lack of adequate transmission capabilities due to damaged transmission lines. In fact, the transmission and distribution system were also heavily impacted by the conflict with over fifty percent of each unavailable either due to direct damage or to lack of maintenance during the conflict.

An examination of the post-conflict reconstruction efforts in Bosnia-Herzegovina (BiH) indicates that while the total amount of reconstruction funds required was quite substantial, the amount spent to rehabilitate individual generating units was relatively modest. The first reconstruction project spent approximately $50/kW to restore and rehabilitate plants with a total capacity of 960 MW, significantly less than what it would cost to build new plants.[5] Thus, a small amount of damage to a centralized power generating facility is sufficient to render it inactive. As noted above, the transmission and distribution systems were also heavily damaged and account for a significant portion of the reconstruction efforts. Of the $170 million cost of the second rehabilitation project, approximately equal amounts were allocated to generation ($46.01 million), transmission ($44.3 million), and distribution ($47.02 million) with the rest for coal mine rehabilitation and other technical assistance.

The electricity and mining sectors were not the only energy infrastructures to be impacted by the war. As some decentralized electricity options would rely on natural gas, it is instructive to review the impacts of the Bosnian conflict on the natural gas pipeline system. While there was some damage to the transmission and distribution network for natural gas, a number of the post-war problems were due not to direct damage but lack of maintenance during the conflict and a sharp increase of illegal and makeshift connections to the network during the war. Prior to the war, the natural gas system served primarily a few industrial customers and the city of Sarajevo. During the conflict, natural gas, which was imported from Russia, was shut off to all parts of the network except Sarajevo. Within Sarajevo the

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[3] Unless otherwise noted, information for this section is from World Bank 1996 and World Bank 1998. Note: The World Bank, in addition to providing some loans and credits, coordinates the international efforts in this area. Thus, World Bank documents on this topic include information on the entire reconstruction effort, not just the Bank's contribution.

[4] Bosnia-Herzegovina is one state consisting of two entities, the Bosnian Federation and the Republika Srpska. The Bosnian Federation is that portion of Bosnia-Herzegovina that is jointly controlled by the Bosnians and the Croats. A second entity, the Republika Srpska is Serbian. Comparable information could not be found for the Republika Srpska. The one pre-war state monopoly electric company was divided into three companies, one for the Serbian republic, one for the Croat portion of the Bosnian Federation, and one for the Bosniac portion of the Bosnian Federation. Part of the post-war efforts have been to improve coordination among the three entities.

[5] Items requiring repair ranged from generator units to control systems to cooling towers. While critical to the operation of the plant, they are only a fraction of the cost of a new plant, which would include a number of cost items of no risk to attack (e.g. purchase of the land, site surveys). In addition, despite sustaining some physical damage, these plants do appear to have much of their overall structure intact.

flow was reduced and only residential customers and small commercial consumers continued to receive gas. As a result, gas consumption dropped from the pre-war level of 610 million cubic meters (for all customers in Bosnia-Herzegovina) in 1990 to 125 MCM by 1992. As Sarajevo's access to other forms of energy decreased during the conflict, including their access to electricity, residents apparently increasingly turned to the natural gas system to provide energy. By the end of the war, natural gas supplied 70% of the energy use in Sarajevo, mainly for cooking and heating (World Bank 1997, pp. 4-9). Thus a major focus of the post-war efforts (which amounted to $43.5 million) was to regularize the connections, establish metering and billing for new connections and rehabilitation of the transmission and distribution pipelines. (World Bank 1997, World Bank 1999a Annex 6, World Bank 1999b p. 28) While a thorough analysis remains to be completed on the robustness of the natural gas system under conflict conditions, the experience in Bosnia-Herzegovina would indicate that as long as supply can be assured, natural gas can continue to be provided in a way that electricity cannot.

One other problem with the functioning of the electric grid in Bosnia-Herzegovina which continued after the end of the conflict, has to do with the collection of revenue by the three electric power companies. During the war, revenue shortages were severe, with collection dropping to as low as 25% of the amounts invoiced. Since the end of the war, revenue collection has improved greatly, but as of 1998, the Bosnian and Serbian electric companies were only recovering 90% and 80% of their invoiced amounts respectively (World Bank 1998, p. 4). Improving cost recovery (including through a new tariff structure that reflects costs), expanding metering of electricity connections, and restructuring of the electricity sector have been part of the post-war effort.

2.2. Lebanon[6]

The electric power sector of Lebanon was also impacted heavily by the fighting in that country with significant portions of the generation, transmission, and distribution systems damaged. For example, in 1993 less than half of the 1350 MW of generating capacity was available (CDR 1996). Electricity was severely rationed such that customers had access to electricity for only six hours out of every day.[7]

The cost of rehabilitation of the electric power grid, while significant, is on the same order as in Bosnia. The generation reconstruction project, costing a total of $106 million (1996), resulted in the rehabilitation of 1049 MW of capacity (about 80% thermal and 20% hydro). Rehabilitation of the transmission and distribution system cost $85 million and $112 million respectively with another $35 million being spent on complementary activities (e.g. coordination and supervision) (CDR 1999). However, as part of the redevelopment effort the electricity grid is being expanded and upgraded to meet demand. In total, approximately $1.4 billion is being spent to rehabilitate existing generation, transmission, and distribution infrastructure as well as to expand the infrastructure to meet increased demand. Of this amount, the majority is being spent on construction of new generating plants (~$575 million) and extension of the power transmission network ($359 million). In particular, two new combined cycle power plants are being built. Each plant will have a capacity of 435 MW (at a cost of approximately $260-$275 million each or around $600/kW) (CDR 1998 and CDR 1999).[8] To place the amount being spent on electric power rehabilitation and expansion in

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[6] Unless otherwise noted, information in this section is from the annual reports of the Council for Development and Reconstruction (CDR), which can be found on the web at http://www.cdr.gov.lb.

[7] It is not specified in the CDR report whether electricity rationing to six hours per day was for the entire country or just for Beirut or other large urban centers. There were presumably large differences in electricity supply to rural versus urban customers prior to and during the war.

[8] The currency year is unfortunately not specified.

perspective, the total value of contracts awarded between 1992 and the end of 1998 for the electricity sector is $1.338 billion out of a total $5.39 billion. It has the largest share of all of the sectors (telecommunications and posts coming in second at $798 million).

It should be noted that while the Lebanese civil war is over, the Lebanese electric power grid continues to be a potential target of attack. As recently as May of 2000, the Israeli air force attacked strategic power generation stations and transmission substations, knocking power out as far north as Beirut.[9] Thus, the vulnerability of the electric power grid continues to be of issue in Lebanon.

2.3. The Unique Nature of the Problem

The examples provided by these historical cases point to the need to treat electricity planning under these circumstances differently than one might if deliberate destruction of electric power infrastructure were not an issue. While planning for such eventualities may be similar to planning in areas where extreme weather events are recurrent (a common requirement in electric power planning is to plan for extreme weather), there are some significant differences.

1) Persistence of Adverse Conditions: Unlike an ice storm or hurricane, the adverse conditions we are considering are not short-term random events. They can re-occur (e.g. a facility can be attacked more than once) and depend on intervention to remove the condition (i.e. a concerted effort by those involved to solve the military situation instead of just waiting out the storm and picking up the pieces). This also impacts the ability to conduct routine maintenance, to obtain replacement parts in order to undertake repairs, and to ensure the safety of personnel.
2) Length of Outage: Obviously this is related to the above item, but it is important to note that under the adverse conditions we are considering outages that can persist for much longer than days or months due to lack of funds, inability to undertake repairs under the adverse conditions, repeat damage, etc. That regular outages of this length are not normally considered by electricity planners is evidenced by the fact that a "Sustained Interruption" is generally classified as one that lasts more than one hour and that there is no classification level for longer durations.
3) Scope of Damage: Under normal operating conditions, the vast majority of outages and customer interruptions are due to problems with the distribution system (and to an even lesser degree, the transmission system).[10] Hurricanes and other extreme events (such as the Quebec and Northeast ice storm) affect mostly these portions of the grid. In 1993, for example, weather was responsible for almost half of the disturbances and unusual occurrences in the U.S. electric grid (see Figure 1). However, in conflict situations it is not only the transmission and distribution system that is at risk. Generating stations and transformer sub-stations can also be affected by conflict or other adverse conditions. Of course, reliability assessments already account for the possibility of failure of a generating unit or a sub-station transformer, but it is not clear that the level of damage contemplated here has been part of the calculations before. For example, the assumption of having a back-up transformer to take over in case of a failure may not be relevant if the substation is bombed. Or, using some reserve capacity temporarily to cover the failure of a component at the hydro generating site is different than having the generating site permanently knocked off

[9] See for example, BBC 2000.

[10] The failure of distribution equipment within 1/2 mile of the user is the cause of 60% of interruptions to the customer (Willis and Scott 2000, p. 15). While it is not specified, this is presumably an average for the U.S. electricity system.

the system because the turbine room is flooded due to a bomb breaching the building structure.

4) Coordination of Attack: It is possible that multiple facilities are attacked in a coordinated fashion in order to maximize damage to the system. This may have been done at least once in El Salvador. As a result of sabotage campaigns, the FMLN were able to interrupt service to up to 90% of El Salvador at times and even produced manuals on disrupting electricity systems (OTA 1990, pp. 15-16).

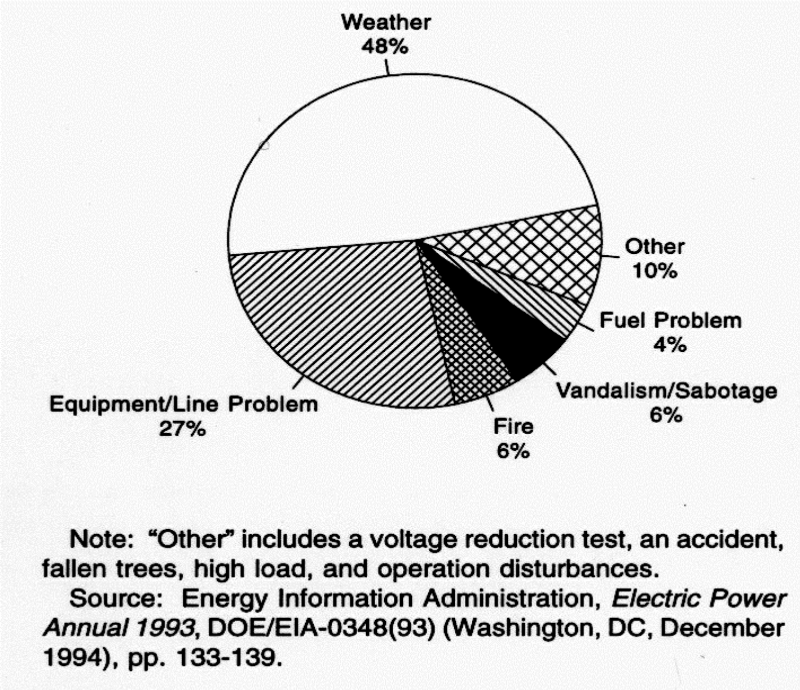

Figure 1: Percent of Major U.S. Electric System Disturbances and Unusual Occurrences by Cause of Outage, 1993

Thus, the historical pattern of electricity infrastructure being attacked during conflict and the differences between these types of contingencies and the ones usually dealt with in electric power planning point to the need for an analysis of the problem and potential solutions.

3. Economics of Centralized versus Distributed Generation Using Cogeneration

One potential solution to the problem of targeting of the electric power infrastructure would be to change the physical characteristics of the electric power grid. As discussed above, an increasingly decentralized grid would be more robust under attack by reducing reliance on a small number of large power plants and by placing generation closer to the points of demand and thus reducing reliance on transmission and distribution. However, the economic implications of such a solution are important.

In general, the costs of distributed generation do not compare favorably with central electricity generation for the same level of service when considering the production of electricity alone. For electricity only distributed generation, it's advantage is that it can be either more reliable (at a higher cost) or less expensive (at a lower level of reliability). (Willis and Scott 2000, p. 9) However, if the cogeneration of heat is included the economics of distributed generation can compare favorably to centralized generation. (Strachan 2000).

A static optimization model was developed by Strachan to minimize total costs for meeting both the energy and heat requirements of two U.S. states (New York and Florida). Consideration of these states allow differing heat to power ratios (HPR) to be compared as the states have different compositions of demand and seasonality characteristics. These differences span a wide range of heat-to-power ratios (critical in the economics of cogeneration) and load factors. The study only focused on natural-gas fired technologies in order to focus on synergies between the networks for provision of electricity and heat. Natural gas-fired distributed generation is highly energy efficient due to its cogeneration of electricity and heat and its avoidance of electricity transmission losses. The study was a "green-field" study in that it did not consider pre-existing infrastructure but rather minimized costs for a new infrastructure. Table 1 summarizes the costs of our various technologies in per kW and per kWhr terms, to enable comparison between technologies of such variety of sizes.

Table 1: Optimization model sample parameters

Technology	Units	Steam turbine	CCGT (elec)	Gas turbine	GT (elec)	Engine	Micro-engine	Large boiler	Small boiler
Capital cost	$/kWe	600	550	500	400	700	1000	200	300
O&M cost	¢/kWh	0.7	0.85	0.85	0.7	1	1.5	0.4	0.5
Gas price[11]	¢/kWh	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Lifetime	Years	30	30	20	20	15	15	20	15
Capital cost Recover in 15 yrs	$/kWe	497	456	459	367	700	1,000	184	300
Electricity transmission cost	¢/kWh	1.88	1.88	0.77	0.77	0.24	0	-	-
Gas trans. cost	¢/kWh	0.04	0.04	0.13	0.13	0.44	0.66	0.44	0.66
Heat trans. cost	¢/kWh	1.32	-	0.88	-	0.26	0	0.26	0
Elec. network efficiency	%	91.7%	91.7%	95.8%	95.8%	100%	100%	-	-
Gas network efficiency	%	99.3%	99.3%	99.0%	99.0%	98.7%	98.7%	98.7%	98.7%
Heat network efficiency	%	80.8%	-	94.3%	-	98.1%	100%	98.1%	100%
Plant efficiency	%	36%	55%	34%	34%	29%	26%	92%	90%
Maximum HPR	#	1.5	-	1.65	-	2.1	2.5	-	-
Electrical Size	KWe	500,000	100,000	10,000	10,000	500	10	-	-
Heat Size	KWth	750,000	-	16,470	-	1,050	25	500	25

Strachan's study finds that energy losses in transmission and delivery of electricity far outstrip those for delivery of natural gas to the end user. It also finds that when cogeneration units can use the co-products of heat and power effectively, they are far more efficient than central power generation and local boilers. His study finds that even natural gas fueled internal combustion engines have lower costs than the current centralized approach to power generation. Other technologies such as micro-turbines promise even greater reliability and economic advantage. The costs of using conventional electricity-only and heat-only generation were 36% higher than distributed generation using internal combustion engines in the case of New York. For Florida, conventional generation is 27% more expensive (the savings are less due to its lower heat demand). The savings realized by IC engine distributed generation apply to the entire energy system and require consistent energy loads, preferably matching the HPR characteristics of the distributed generation plant. These consistent loads can be achieved by aggregating sectoral loads in order to reduce variation in demand and

[11] To convert from ¢/kWh (of input fuel energy, as conversion efficiencies are factored in later in the model) to $/m cu.ft. for gas, use 1kWh=3.6MJ, natural gas has 39.1MJ/m^3, and 1m^3 = 35.3cu.ft. Thus 1 ¢/kWh = 3.08 $/m cu.ft. of gas. Thus for our model values: 0.89 ¢/kWh for natural gas = 2.74 $/m cu.ft.

points to the need to stimulate joint energy supply ventures between different customer classes.

Factors such as natural gas usage and the social costs from production of pollutants were also modeled. Savings due to cogeneration are substantial compared to conventional energy supply for both private investors and for the network of which the system may be a part. This finding leads to the counter-intuitive conclusion that centralized power systems should facilitate expansion of distributed cogeneration within their territories up to calculable upper bounds dictated by their electricity and heat demand characteristics.

This engineering-economic analysis will be augmented with a robustness engineering analysis. If distributed generation proves to have more robust characteristics than centralized generation, there may be additional economic costs to maintaining centralized generation that have hitherto been ignored. These economic costs will depend upon the probability and level of disruption to the system. The value of the robustness can be calculated and used in comparing the economics of different systems. This will also aid in putting a cost estimate on any institutional biases towards large centralized systems within international aid organizations and electric power planning bodies.

4. Reliability Assessment

A number of methodologies exist in order to assess the reliability of electric power systems. Generally, the literature reduces the electric power grid to three hierarchical levels. The first looks only at the generating system in order to determine whether generating capacity is sufficient to meet demand. The transmission and the distribution systems are assumed to work perfectly in such analyses. Composite system or hierarchical level II analyses include both generating capacity and the transmission system, but distribution is not considered. Finally, hierarchical level III analyses consider only the distribution system and assume fully functioning generating and transmission systems. Depending on the level of the analysis, different reliability indices can be calculated in order to determine the reliability of a given system. A description of the different reliability assessment methodologies and the various standard reliability indices can be found in any standard textbook on electric power reliability.

4.1. Potential Reliability Impacts of Distributed Generation

Distributed generation has the potential to improve reliability of electricity service because, as noted above, it places the generation source closer to the demand centers. The combination of having many units in operation, thus reducing reliance on a small number of large generators, and the reduction in transmission and distribution, provides certain advantages over centralized generation.

In a stand-alone system, without grid support, the availability of having two plants instead of one is different and the resulting reliability characteristics will be more or less favorable depending upon the needs of the customer. With one unit, the probability of having no power is larger. With two units, the probability of half the capacity being unavailable is larger (since half the capacity will be lost if either unit is unavailable). (Willis and Scott 2000, p. 345) However, in general, the resulting reliability is less than with the electricity grid because the unavailability of individual units is higher than the grid system as a whole. With distributed generation that is grid-connected, those concerns are lessened because the customer can rely on grid power when their individual unit is unavailable (Willis and Scott 2000, p. 371). As noted above, the costs of using DG for electricity only tend to be higher than with conventional electricity generation, unless cogeneration is used.

Grid interconnection is also an issue that must be considered when examining electricity systems with a high level of distributed generation. Traditionally, electricity grids were run in one direction, with electricity flowing from generators, through the grid, to consumers. Distributed generation places generators within the grid and requires the DG units and the grid to be run in parallel and coordinated. While this poses some problems for control of the grid, these problems can be addressed through digital control equipment (Willis and Scott 2000, pp. 372-373). The issue of how to interconnect and control DG units in a grid is an active area of research and should not be an issue of concern for the problem at hand.

4.2. Generating Capacity Assessment

In order to assess the relative robustness of centralized and distributed electric power systems, an engineering analysis is being conducted that will model their survivability under adverse conditions, in particular, deliberate attacks upon the system. Each will have characteristic failure modes and probabilities, including possible dependencies on major supporting infrastructure networks (such as natural gas delivery for distributed cogeneration) that will provide differing responses to adverse conditions.[12] A set of metrics will be determined by which the performance of different systems under adverse conditions can be judged.

A generating capacity adequacy assessment is the first portion of the engineering analysis to be developed. A Monte Carlo simulation was developed in Visual Basic that compares hourly demand to hourly capacity levels to determine if demand has been met. The model uses a System State Duration Sampling method that compares available capacity to demand on an hour-by-hour basis over a number of simulated years and follows the standard framework established in reliability texts (in this case we have used Billinton and Li 1994, pp. 76-79). The state of each generator is tracked and new failure and repair times for a generating unit are calculated when a transition occurs. Times to failure and times to repair are based upon a known failure rate (λ) and a known repair rate (μ). The time to the next failure or repair can be calculated by assuming exponential distributions for failure and repairs and using the inverse of the cumulative distribution function of the exponential:

$$\text{Time to Failure (TTF)} = \text{MTTF} * \ln(U)$$
$$\text{Time to Repair (TTR)} = \text{MTTR} * \ln(U')$$

where:
U and U' = a random number from 0 to 1 drawn from a uniform distribution
MTTF = Mean Time to Failure ($1/\lambda$)
MTTR = Mean Time to Repair ($1/\mu$)

As noted above, the model compares capacity and demand in every hour. For a given model run (which corresponds to one year) the number of hours in which capacity did not meet demand (Loss of Load Duration – LLD) and the energy shortfall in those hours (Energy Not Supplied – ENS) are recorded. If N years are simulated then the reliability indices (and their variances) can be calculated (readers are referred to Billinton and Li 1994, pp. 77-78, for more information).

The Reliability Test System (RTS) of the IEEE was used in order to validate the model (the IEEE RTS is described in Billinton and Li 1994, Appendix A). The IEEE RTS has 32 generators, ranging in capacity from 12 MW to 400 MW, and provides mean times to failure and repair. Simulating this system allows a comparison to previous Monte Carlo

[12] Other possible infrastructures which could have interdependencies with the electric power system include telecommunications (e.g. the use of telecommunications equipment for coordination and control in electric power networks and the need for electric power to run telecommunications equipment) and the railroad (e.g. for transporting coal).

simulation efforts using the same technique and provides a baseline against which to compare more distributed systems. The Loss of Load Expectation (LOLE, hours per year) and the Loss of Energy Expectation (LOEE, MWh per year) were calculated in Billinton and Li using 2500 simulated years. In order to reduce computational effort, 2500 simulated years were not used for the actual model runs described below. Instead, a stopping rule based upon a minimum number of runs and a maximum coefficient of variation was used.

Table 2 compares the result of our model with that of Billinton and Li (Billinton and Li 1994, p. 86) for the base case in the IEEE RTS of meeting 2850 MW of peak demand. There is about a two percent difference between the results reported by Billinton and Li and the results of our model. A peak demand of 3050 MW was also simulated and the results again matched Billinton and Li.

Table 2: Comparison to Billinton and Li Model

Index	Billinton and Li	Our Model
LOLE (hr/yr.)	9.4	9.57
LOEE (MWh/yr.)	1200	1180

In order to determine the impacts of violent conflict on generating capacity adequacy, the failure and repair rates for the generators will be treated as parameters and varied. We have begun by maintaining the same time to failure parameter, but have varied the mean time to repair. The model was run and each time the MTTR for each unit was multiplied by a constant (from 1 to 5). It should be noted that, even at five times the original MTTR, the mean repair times still range from 100 to 750 hours (or 4.2 days to one month) and thus do not seem unreasonable as possible repair times during conflict. Figure 2 shows the results of changing the Mean Time to Repair of each generating unit in the IEEE RTS. Thus, MTTR/MTTRbase of 2 indicates a doubling of all of the MTTR from the original values. The resultant reliability indices for that run are then divided by the index when all MTTR values are at their base value. As can be seen, both the loss of load expectation (LOLE) and the loss of energy expectation (LOEE) increase greatly as the time it takes to repair the units increases. Doubling the MTTR results in the LOLE increasing by a factor of six and the LOEE increasing by a factor of eight. As the MTTR is increased further, the impacts become even more severe.

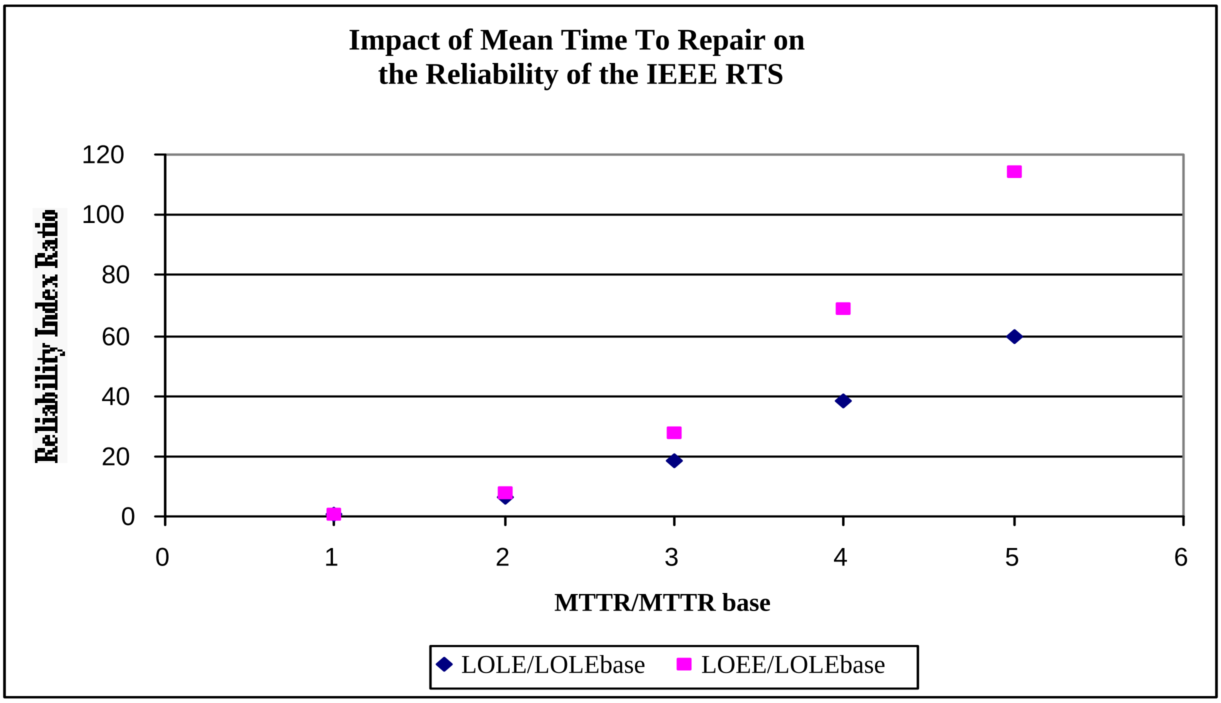

Figure 2

However, it is necessary to compare these results to the behavior of a more distributed system under these same circumstances. The generating system in the IEEE RTS was replaced with 284 generating units, each with a capacity of 12 MW. This provides approximately the same total generating capacity as in the RTS. The 12 MW units were chosen because they are the smallest units in the RTS and are close to the upper range generally considered for distributed generation. However, replacing a given generating capacity with a large number of smaller units always results in much lower figures for the reliability indices (i.e. higher reliability). In order to make a proper comparison, therefore, the demand that the 284-unit system was required to meet was increased until the resulting reliability index for LOEE roughly matched that under the base IEEE RTS case (the LOEE was used because it was more sensitive to changes in MTTR). As a result, this system meets a peak demand of 3505 MW with a base LOEE (i.e. with the mean time to repair set at its nominal value) of approximately 1080 MWh/yr.

The mean time to repair of the 12 MW generating units in the 284-unit system was then varied in the same manner as for the IEEE RTS system. The results are shown in Figure 3. Again, the LOEE is more sensitive than the LOLE to changes in the mean time to repair.

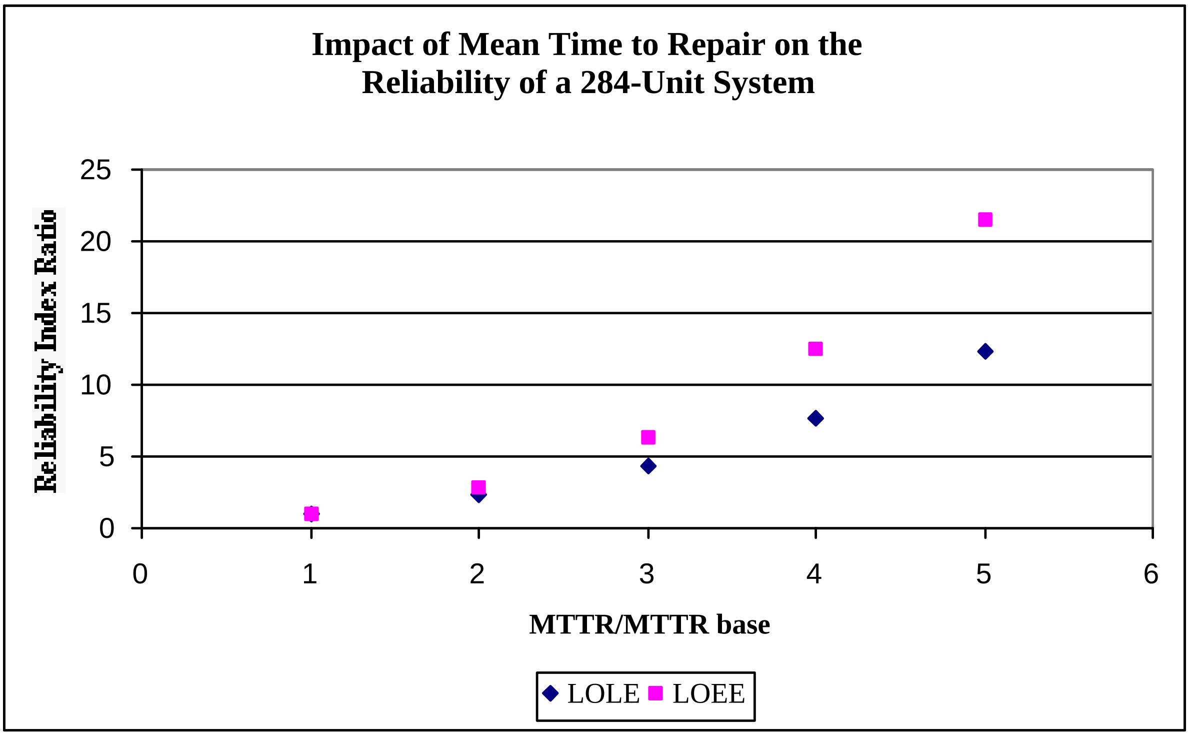

Figure 3

However, a comparison of the IEEE RTS and the 284-unit system indicates that the more distributed system clearly performs better when the mean time to repair is increased. Figure 4 compares the change in LOLE of the two systems and Figure 5 compares the LOEE of the two systems. A doubling of the MTTR results in an LOLE that is 2.3 times the original in the case of the 284 unit system. By contrast, doubling the MTTR in the IEEE RTS results in an LOLE six times larger. If the MTTR is multiplied by a factor of five, the LOLE changes by a factor of 12.3 in the 284 unit case, but it changes by a factor of 59 in the IEEE RTS case. Similar results hold for the LOEE. A factor of five change in MTTR results in a factor of 22 change in the 284-unit case and a factor of 114 change in the IEEE RTS case.

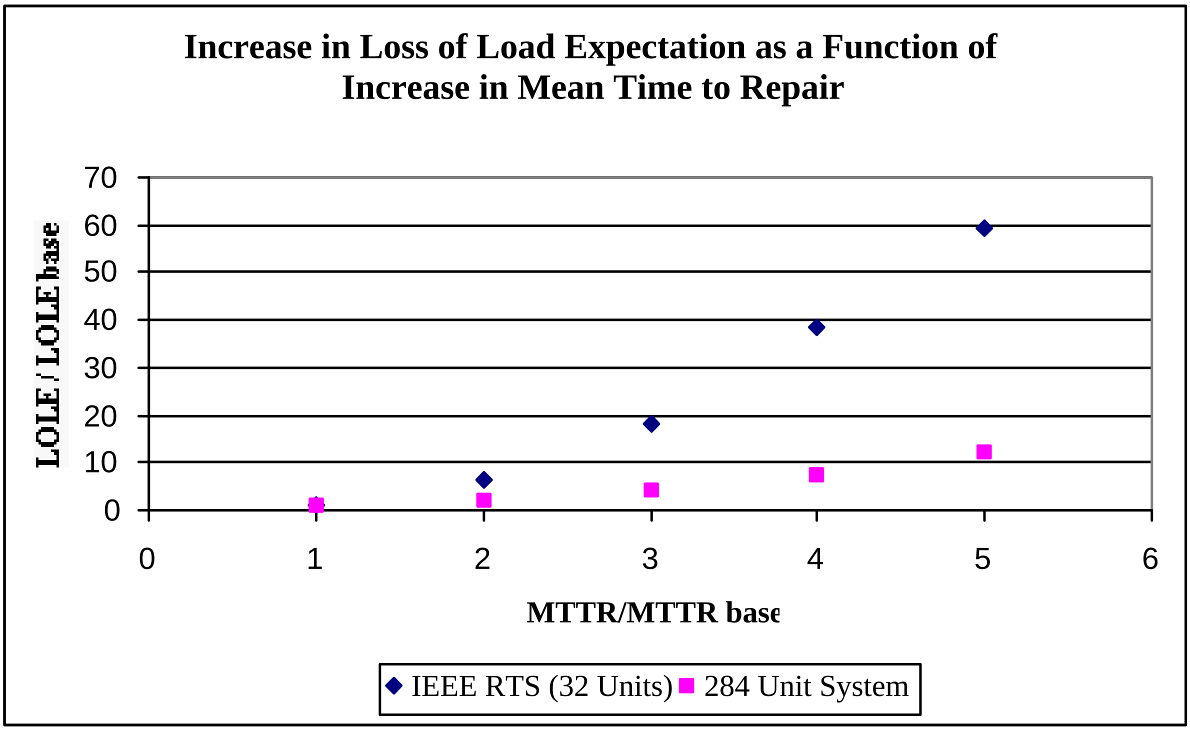

Figure 4

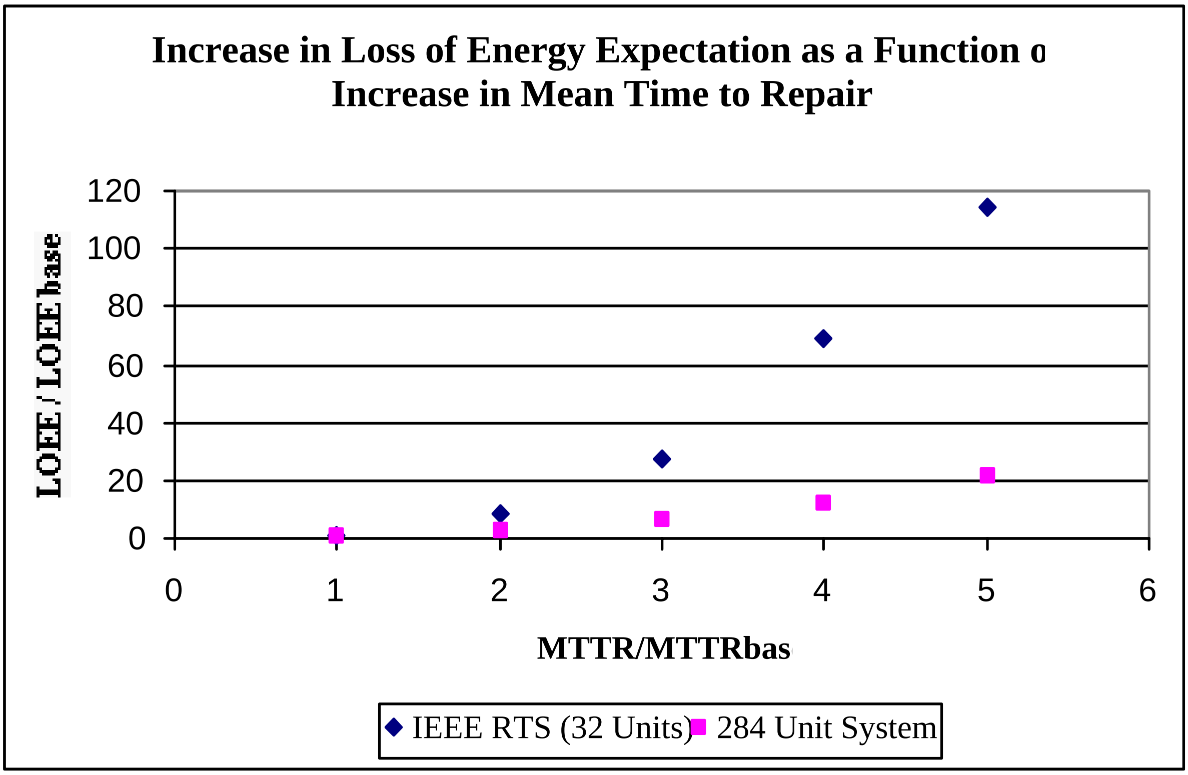

Figure 5

4.3. Future Work

In order to determine whether some computational time can be saved without loss of accuracy in results, the model will be modified to use a State Sampling Method. The State Sampling Method does not attempt to model the system on an hour-by-hour basis, but rather using the probabilities of capacity and demand states. This reduces the computations required, however, it has the disadvantage of not being able to calculate the frequency index of capacity not meeting demand (Billinton and Li 1994, p. 91).

However, generating capacity adequacy is only the first step in analyzing the reliability of an electric power system. Future work will include adequacy assessments that account for transmission and distribution as well as the stability of these systems when disturbed. Further work will have to be done to assess the robustness of natural gas delivery networks. If possible, historical data on outages during conflict will be assessed in order to determine appropriate values for the model parameters.

This engineering analysis will be coupled with the economic analysis of electricity systems presented above, including the extension to include the value of increased robustness under adverse conditions.

5. Conclusions

The historical record of the conflicts in Bosnia-Herzegovina and Lebanon indicates the need to consider deliberate attacks when planning electric power systems in areas with the potential for violent conflict. The particular features of this context make it different than planning for severe weather events of isolated acts of sabotage. Distributed generation, including the use of natural gas fired cogeneration systems, holds the promise of improved reliability and maintenance of service under these conditions. This could further improve the economics of distributed generation as compared to centralized power generation.

A cost optimization model found that if the costs of supplying both electricity and heat are considered, then distributed cogeneration using internal combustion natural gas fired engines was the lowest cost option. However, this requires a good match between the heat to power characteristics of the distributed generation technology and the demand. Load aggregation can reduce variation in demand and result in a closer match between demand and generation. The resulting cost savings for the entire energy system are substantial.

In order to determine the reliability advantages offered by distributed generation, a Monte Carlo simulation model was developed to conduct generating capacity adequacy assessments. The model was used to determine the Loss of Load Expectation (hr/yr.) and Loss of Energy Expectation (MWh/yr.) for both a standard test system (the IEEE RTS) and for a system consisting of 284 identical 12 MW units. In order to simulate the effects of conflict on the system, the mean time to repair for each unit (in both the IEEE RTS and the 284-unit system) was increased and the reliability indices re-calculated. The results show that the system consisting of a large number of smaller units is up to 5 times less sensitive to changes in the MTTR (for the range of changes considered in the model). This supports our hypothesis that distributed generation systems will have improved reliability over centralized systems when operated under adverse conditions. Work will be conducted to further validate this hypothesis (for example, by including network effects) and to assess the economics of such systems.

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