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Electricity and Conflict: Advantages of a Distributed System

With recent events having highlighted the need to consider deliberate attacks when planning electric power systems, it is pertinent to make a quantitative comparison of an electricity system based on distributed natural-gas-fired units to a traditional system based on large centralized plant. The distributed system proves to be up to five times less sensitive to measures of systematic attack.

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I. The Policy Issue of Electricity and Conflict

Attacking infrastructure is a common practice in military conflicts and electric power systems are obvious targets for attack. As electricity cannot be easily stored or rerouted, supply must match demand. In an integrated electric system, a disruption can bring large parts of the network down.[1] This can have severe economic impacts,[2] and pose a threat to human life. Such impacts have been seen in a variety of conflicts, such as Bosnia. However, the rise of organized and systematic global terrorism has demonstrated that a deliberate attack on an electricity system is an issue for all countries, not just those undergoing conflict.

Planning for reliable electricity supply has traditionally involved a careful analysis of equipment failure and redundancy needed to continue service. Planning for demand and restoration of service at times of weather extremes (e.g., hurricanes) is also common practice. However, preparing for the eventuality of a deliberate attack is significantly different from preparing for random equipment failure, a hurricane, or a heatwave. The deliberate nature of damage to the system, the broader range of system components that can be impacted, and the persistent nature of the damage create a different set of planning conditions than those normally considered.[3] These include:

Coordination of attack. Unlike equipment failures or even extreme weather events, deliberate attacks are not short-term random events. Military units and terrorists both have the capabilities to coordinate attacks and intentionally maximize damage to the system. For example, the Farabundo Marti National Liberation Front (FMLN) was able to interrupt service to up to 90 percent of El Salvador at times and even produced manuals on disrupting electricity systems.[4] Attacks can also be repeated as system components are repaired.

Scope of damage. The failure of distribution equipment within a half-mile of the customer is the cause of 60 percent of interruptions in the U.S.[5] However, in conflict situations, remote transmission lines, generating stations, and transformer sub-stations can also become targets in a conflict. It is not at all clear that existing reliability assessments account for the possibility of multiple component failures, failures across a broader set of components, and the subsequent impacts on the integrated electricity network.

Persistence of outage. Deliberate attacks may not be single events, and they may occur under conditions (or create conditions) which make restoration of service and repair more difficult. When they do occur, factors such as safety of personnel, lack of funds for replacement parts, absence of technical expertise, and the possibility of subsequent sabotage can result in outages that persist for days or even longer. Outages of long lengths are not normally considered by electricity planners in developed countries (a ''sustained interruption'' is generally classified as one that lasts more than 1 hour; there is no classification level for longer outages[6]).

Policy consideration of conflict on electricity systems can be different for countries at varying stages of economic development or at different risk to deliberate attack. **Table 1** presents a simplified classification.

In general, less industrialized and at risk countries have not been able to consider conflict in electricity planning due to their limited resources to deal with this issue. However, their energy systems are less developed and, as part of expansion planning, can be designed to withstand attacks more effectively. On the other hand, more industrialized countries are now forced to reassess their relatively mature energy systems against attack. They have large sunk costs in infrastructure, but have greater capabilities to meet this challenge. We suggest that in a highly integrated economy, economic losses from significant electricity disruptions would be greater, but lack of resources would mean health and mortality consequences would be more severe in developing countries.[7]

To complete this introduction, Bosnia–Herzegovina is discussed as a recent example[8] of deliberate targeting of electric power infrastructure. Information on conflicts in these countries clearly indicates that a relatively small amount of damage can result in severe and long-lasting

Table 1: Country Differences for Electricity Systems and Conflict

	More Industrialized/Least Risk	Less Industrialized/Most Risk
Electricity planning	Conflict rarely considered	Conflict rarely considered
Type of conflict	Systematic terrorism	War or terrorism
Electricity infrastructure	Existing	Growing
Natural gas infrastructure	Existing	Growing
Finance	Available	Sparse
Engineering skills	Available	Sparse
Replacement parts	Available	Sparse
Economic loss	Highly integrated economy	Less integrated economy
Threat to human health	Possible	Likely

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disruptions to an electricity system.

Prior to the war in Bosnia–Herzegovina,[9] electricity consumption was approximately 12,000 GWh (1990). Demand was met by a domestic combination of coal-fired thermal plants (about 72 percent of supply), and hydropower plants (about 28 percent of supply).[10] By 1996, the electricity production situation in Bosnia had dramatically changed. Over 56 percent of total generating capacity was unavailable due to direct damage. Of the remaining capacity, a lack of fuel (the mining sector was also targeted), and 50 percent loss of both transmission and distribution system capacity (often from lack of maintenance) severely impacted supply.

Post-conflict, electricity infrastructure reconstruction costs were relatively modest. The first rehabilitation project spent approximately $50/kW to restore and rehabilitate plants with a total capacity of 960 MW. This cost is a factor of 10 less than new plant construction. Thus, a small amount of damage to a centralized power generating facility is sufficient to render it inactive. The second rehabilitation project (budget $170 million), allocated approximately equal amounts to generation ($46 million), transmission ($44 million), and distribution ($47 million) with the remainder for coal mine rehabilitation and other technical assistance.

The impacts of the Bosnian conflict were much less severe on the natural gas infrastructure. There was limited damage to the largely underground natural gas transmission and distribution network, and many of the post-war problems were due to lack of maintenance and a sharp increase of illegal and makeshift connections. Prior to the war, the natural gas system served major industrial customers and the city of Sarajevo. During the conflict, imported natural gas was shut off to all parts of the network except Sarajevo, where the flow was reduced and restricted to residential and small commercial consumers.[11] As a result, gas consumption dropped from 610 million cubic meters (MCM) in 1990 to 125 MCM in 1992. Natural gas became the major source of energy in Sarajevo (with the unavailability of electricity) and supplied 70 percent of the city's energy use by the end of the war. While a thorough analysis remains to be completed on the robustness of the natural gas system under conflict conditions, the experience in Bosnia–Herzegovina indicates that as long as supply arrangements can be assured, natural gas can continue to be provided when electricity cannot.

II. Why Consider a Distributed System?

We will argue in this article that a system primarily based upon natural gas distributed (co)generation or distributed generation (DG), will be more robust under the adverse conditions of conflict. We will also argue that an integrated energy generation and delivery network based on current DG technologies can offer economic savings even if the reliability gains are not included.

There are a number of reasons why a system based on natural gas DG units (i.e., a much larger number of generators closer to the demand load) would be expected to be more robust under conflict:

1. 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.
2. Even if security for large generators can be assured, the electricity transmission and distribution system largely cannot. DG can reduce reliance on the T&D electric grid.
3. Natural gas transmission and distribution systems (which would be needed anyway for

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on-site heat-only plant) are generally underground and therefore better protected than electrical transmission and distribution lines.

4. Gas pipelines do not have the strict real-time operational problems that electric power grids do when there is a disturbance to the system. In electric power grids, a disturbance to one part of the grid can result in cascading failures that knock out power to a much wider area than the original disturbance.

5. A natural gas DG system can have greater robustness through dual fuel technologies and local natural gas storage facilities.

Previous work on the security of energy systems has tended to focus on assuring supply of fossil fuels (i.e., vulnerability to fuel supply disruptions), large-scale conflict with the Soviet Union (with a particular emphasis on the impact of electromagnetic pulses from nuclear weapons), and isolated acts of terrorism.[12] More recent work on critical infrastructure protection has added the issue of information technology vulnerabilities and highlighted the issue of critical infrastructure interdependencies.[13] The few works that do address possible changes to the overall physical topology of the system, including some that have directly addressed the reliability advantages of DG, have been qualitative in nature.[14] They have not attempted to quantify in a systematic manner both the reliability advantages and the economic consequences of using DG in times of conflict. Furthermore, there have been a number of changes in both the political and security context in which these technologies are assessed as well as significant changes in the technical and economic characteristics of electricity production technologies in the intervening years.

The next two sections discuss reliability and economic comparisons of a system based on DG relative to conventional electricity and heat production and distribution.

III. Reliability Advantages of a Distributed System

One solution to systematic targeting of the electric power infrastructure would be to change the physical characteristics of the electric power grid. DG has the potential to improve reliability of electricity service because (everything else held constant) the larger the number of power sources, the lower the vulnerability to random unit failures; vulnerable electricity transmission and distribution is replaced with a natural gas network that doesn't require real-time demand and supply balancing, and dual fuel or fuel storage on-site is possible. Lastly, remote digital control of now commercialized DG technologies allows a higher level of reliability and eases the grid control issues that arise from locating DG units within the electric distribution network (since they must still be run in parallel and coordinated with other generation plants).

In order to assess the relative robustness of centralized and distributed electric power systems, an engineering analysis is summarized that models survivability under deliberate attacks upon the system. Each system architecture will have characteristic failure modes and probabilities, including possible dependencies on major supporting infrastructure networks (such as natural gas delivery for DG) that will provide differing responses to adverse conditions. The full details of the modeling process are presented elsewhere.[15]

The first step in the reliability analysis is to set up a model of generating capacity adequacy. A Monte Carlo simulation was developed 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.[16] 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), which are assumed to be exponentially distributed. The time to the next failure or repair can be calculated using the equation for an exponential distribution[17]:

$$\text{Time to failure (TTF)} = \text{MTTF} \times \ln(\text{U})$$

$$\text{Time to repair (TTR)} = \text{MTTR} \times \ln(\text{U}')$$

where U and U′ are random number from 0 to 1 drawn from a uniform distribution, MTTF the mean time to failure ($1/\lambda$) and MTTR is the mean time to repair ($1/\mu$)

Hence, the model compares capacity and demand in every hour. The model records the number of hours in which capacity did not meet demand (loss of load duration, or LLD) and the energy shortfall in those hours (energy not supplied, or ENS) are recorded. As N years are simulated then two reliability indices (and their variances) can be calculated:

- Loss of load expectation (LOLE, hours per year);
- Loss of energy expectation (LOEE, MWh per year).

The second step in the reliability analysis is to validate this model against the Reliability Test System[18] (RTS) of the International Electrical and Electronic Engineers society (IEEE). This provides a baseline against which to compare more distributed systems. The IEEE RTS has 32 generators, ranging in capacity from 12 to 400 MW, and provides mean times to failure and repair. **Table 2** confirms that this model was within 2 percent of Billinton and Li for the base case in the IEEE RTS of meeting 2,850 MW of peak demand.[19]

Table 2: Verification of Reliability Model

Index	Billinton and Li	This Model
LOLE (hours per year)	9.4	9.57
LOEE (MWh per year)	1200	1180

The third step in the reliability analysis is to define how deliberate attack is modeled. In order to determine the impacts on generating capacity adequacy, the failure and repair rates for the generators can be treated as parameters and varied. As a first proxy for conflict, the MTTR for each unit was increased by a factor of 1–5. For readers to calibrate themselves, a doubling of the original MTTR results in mean repair times ranging from 40 to 300 hours (or 1.67–12.5 days). This distribution does not seem unreasonable as possible repair times during conflict, given the safety consideration of personnel, the likelihood of systematic attack, and the integrated nature of an electricity network.

The model can now be used to compare electricity systems under conditions of systematic attack. The IEEE RTS generating system is compared to a more distributed system consisting of 284 generating units, each with a capacity of 12 MW. These 12 MW units are the smallest units in the RTS and are close to the upper range generally considered for DG. However, replacing a given generating capacity with a large number of smaller units always results in a higher reliability (i.e., lower figures for the reliability indices, LOLE and LOEE). Therefore, to make a proper comparison, the 284-unit distributed system was required to meet an increased demand where the resulting reliability index for LOEE approximately matched that under the base IEEE RTS case. Alternatively, the distributed system could have had fewer units (i.e., met the same demand and reliability level, but with less generating capacity). In fact, the results are equivalent in either case.

The MTTR was then varied in the same manner for both the IEEE RTS system and the 284-unit distributed system. The results are shown in **Figure 1**a and b. An MTTR/MTTRbase of 2 indicates a doubling of all of the MTTR from the original values. Both the LOLE and the LOEE increase greatly as the time it takes to repair the units increases. The LOEE is more sensitive than the LOLE to changes in the MTTR.

However, it is clear the more distributed system performs better than the IEEE RTS when the mean time to repair is increased (i.e., under simulated conflict conditions). A doubling of the MTTR increases the LOLE by a factor of 2.3 for the distributed

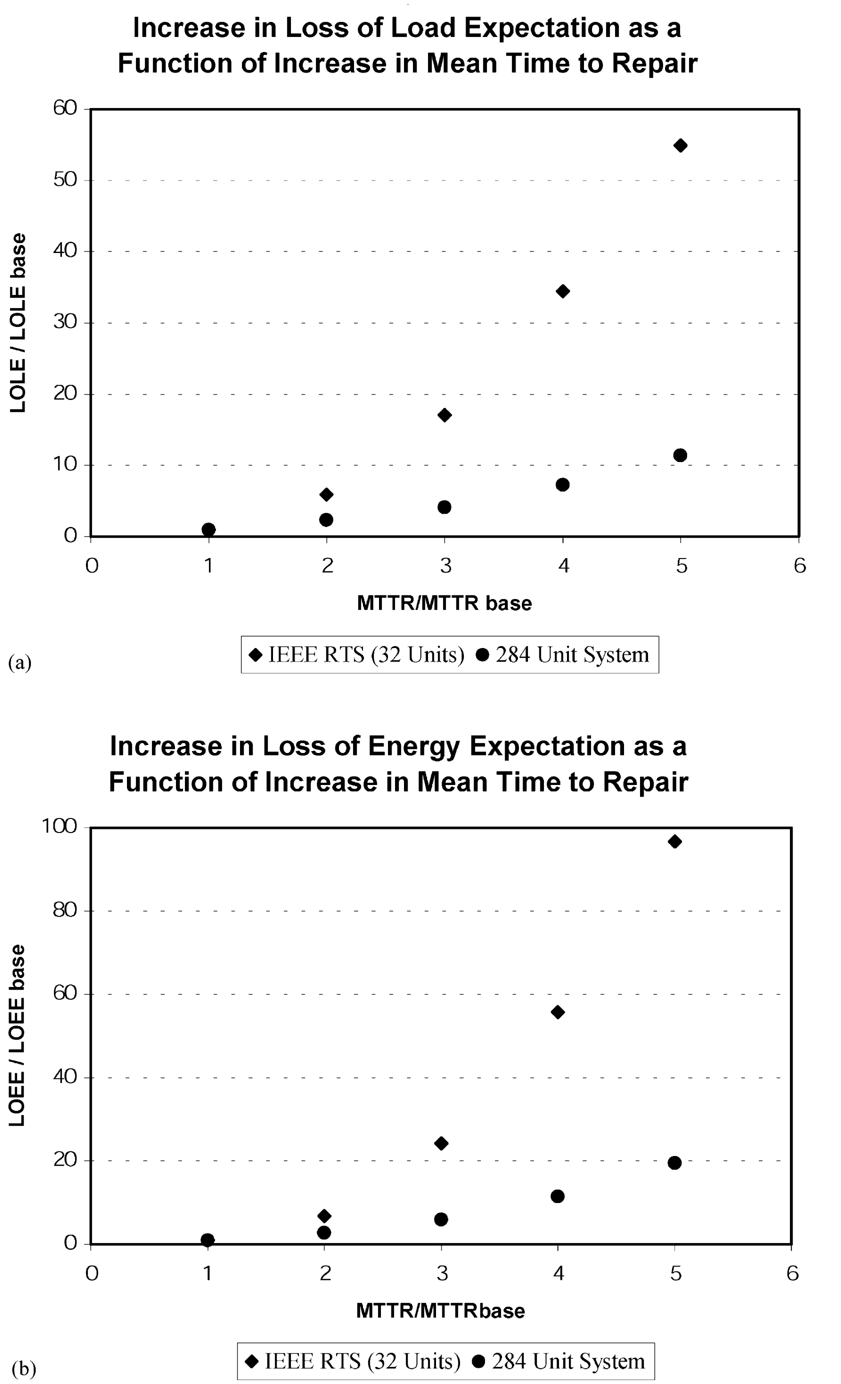

Figure 1: Centralized vs. distributed system comparison under simulated conflict: (a) changes in the LOLE; (b) changes in the LOEE

284-unit system, but increases the LOLE by a factor of 6 for the IEEE RTS system. If the MTTR is multiplied by 5, the LOLE increases by a factor of 12.3 in the distributed system, but increases by a factor of 59 in the IEEE RTS system. Similar results hold for the LOEE, where a multiple of 5 increase in MTTR results in a factor of 22 change in the distributed system and a factor of 114 increase in the IEEE RTS system.

Therefore, this model indicates that a distributed system is up to five times less sensitive to this measure of systematic attack for the range of impacts considered.

However, generating capacity adequacy is only the first step in analyzing the reliability of an electric power system. Ongoing and future work includes improvements to the existing generating capacity model, adequacy assessments that account for transmission and distribution as well as the stability of these systems when disturbed, and consideration of both the costs of supplying electricity and the avoided economic losses that result from maintaining reliability under adverse conditions. 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.

IV. Economic Advantages of a Distributed System

In order to consider DG as a viable alternative to centralized generation in conflict situations, the relative economics of the two systems must also be compared. The range of commercially available natural-gas-fired DG technologies include gas turbines, internal combustion (IC) engines, microturbines, and fuel cells. Distributed (co)generation (DG) technologies can deliver economic and environmental benefits in specific applications with consistent and well-matched electricity and heat demands.[20]

Until now the economies of scale of centralized generation, the use of coal as the dominant fuel for electricity generation, and regulatory barriers or disincentives to on-site generation have precluded the widespread adoption of DG. However, changes in the relative economics of centralized versus DG, the increasing use of natural gas, restrictions on new electricity transmission lines, recognition of the environmental benefits of DG, and improved DG control technologies, have resulted in the reconsideration of widespread use of DG.[21]

But how do the costs of an entire system primarily based on DG compare to conventional centralized electricity generation and delivery and on-site heat production? A static optimization model was developed to minimize total investment and operating costs to meet seasonally varying power 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 demand and seasonality characteristics. New York is a heat-dominated system, particularly in the winter, while Florida's large summer cooling requirements ensure it is an electricity-dominated system. The green-field model used for this analysis compares what it would cost to build a new system based on a conventional supply system versus a network of DG units. The optimization selects investments in energy technologies[22] and their operation regime, from a variety of centralized-distributed and electricity–heat-cogeneration options. Full details of the derivation of input technology and demand parameters, and the detailed specification and testing of the model are presented elsewhere.[23]

For electricity production alone, DG technologies are currently more expensive than large-scale centralized plant. Running the model for electricity supply only, found that a DG system would be 23 percent more expensive for Florida and 26 percent more expensive for New York State. New York's greater variability in electricity demand accounts for the larger cost penalty.

However, the optimal use of DG is to also use the waste heat. This is called cogeneration or combined heat and power (CHP). This greatly increases the efficiency of DG units, with further economic benefits resulting from avoided transmission losses.

Using the aggregated demands for New York and Florida in this green-field model, **Table 3** gives the technology selection and overall costs (over 15 years) when using electricity or heat-only technologies, when allowing progressively smaller cogeneration technologies, and lastly when allowing DG. Capacity and generation by technology of electricity and heat to illustrate base-load versus peak operation are also shown.

Savings due to DG and cogeneration are substantial compared to conventional energy supply. As the available size of the cogeneration technology gets smaller, savings increase, owing both to the improved costs of gas turbines and then IC engines, and to the increased flexibility of smaller units in meeting variable loads. Compared to conventional electricity and heat-only technologies, use of DG results in system cost savings of 30 and 21 percent in New York and Florida, respectively. New York realizes higher percentage cost savings from DG as its greater heat demand allows a higher fraction of the large heat output from IC engines to be utilized. Florida's large electricity requirements ensure electricity-only gas turbines remain a significant part of the generating capacity. Sensitivity analysis for realistic ranges of capital and operating costs as well as natural gas prices support the use of DG up to calculable upper bounds where electricity and heat

Table 3: DG, Cogeneration and Conventional Supply Solutions

Technology Options	Total Cost (B$) (and Savings)	Optimal Technologies	GWe (percent)	GWe (hours, percent)	GWth (percent)	GWth (hours, percent)
(a) New York						
No cogeneration technologies at all	209	CCGT	100	100	–	–
		Heat boiler	–	–	100	100
No micro-engines, IC engines, cogen gas turbines	171	Cogen ST	86.4	75.3	50.9	53.5
		CCGT	13.6	24.7	–	–
		Heat boiler	–	–	49.1	46.5
No micro-engines, IC engines	159	Cogen GT	100	100	53.0	64.1
		Heat boiler	–	–	47.0	35.9
All	146 (30.2 percent reduction)	IC engine	100	100	81.2	87.4
		Heat boiler	–	–	18.8	12.6
(b) Florida[26]						
No cogeneration technologies at all	106	GGCT	27.0	56.6	–	–
		Gas turbine	77.0	43.4	–	–
		Heat boiler	–	–	100	100
No micro-engines, IC engines, cogen gas turbines	102	Cogen ST	21.2	43.8	42.2	54.7
		Gas turbine	78.8	56.2	–	–
		Heat boiler	–	–	57.8	45.3
No micro-engines, IC engines	89	Cogen ST	6.7	12.4	24.7	31.0
		Cogen GT	48.9	66.9	72.9	62.8
		Gas turbine	44.4	20.7	–	–
		Heat boiler	–	–	2.4	1.3
All	84 (20.7 percent reduction)	Gas turbine	66.2	46.0	–	–
		IC engine	33.8	54.0	100	100

demands match the cogeneration characteristics of the technologies.

With widespread use of DG (including other promising technologies such as microturbines and fuel cells), economies of scale in capital and maintenance costs would be expected to improve economic gains from DG technologies. This would also be expected to allow DG to compete on an electricity-only basis. Together with the use of absorption chillers for trigeneration applications, this could allow DG to meet an entire range of electricity heat and cooling demands.

It should be noted that the results presented above are for a green-field system with no existing infrastructure. Modeling of New York and Florida with existing generation and delivery energy systems finds that as electricity demand grows and plants are retired, the optimal technology selection evolves to the DG solution in under 30 years.[24] However, such a transition may not be without its own set of problems.[25] For example, it is possible that existing facilities that have not been paid off would no longer be run, resulting in a problem of stranded assets. A model that includes the transition from an existing centralized system to a distributed system found that existing generating plants were underutilized by 46 percent, indicating that this may indeed be a serious issue. Another potential issue is the rate at which new DG units are built and integrated into the system. The model found that approximately 10,000 DG units would be added in only a few years. This is five times more than was installed in The Netherlands, one of the leaders in the use of DG, in the mid-1990s. Such technical concerns would have to be resolved and could limit the growth rate of DG.

This economic comparison has not considered the economic consequences of varying levels of survivability under conflict. If DG 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.

V. Conclusions

The historical record of regional conflicts, and the rise of global terrorism lead us to limit vulnerability to deliberate and systematic attacks when planning electric power systems. Length of outages, coordination of attack, and scope of damage make conflict conditions very different than random equipment failure, extreme demand, and severe weather events for electricity system planning. Natural-gas-fired distributed (co)generation holds the promise of improved reliability and maintenance of service under these conditions. This is due to less reliance on a small number of large generators, less reliance on a vulnerable T&D electric grid, use of better-protected natural gas transmission and distribution systems which do not have strict real-time operational requirements, greater robustness through dual fuel technologies and local natural gas storage facilities, and lastly, recent improvements in the control and coordination of DG technologies.

In order to determine the reliability advantages offered by DG, a Monte Carlo simulation model was developed to conduct generating capacity adequacy assessments. The model was used to determine the LOLE (hours per year) and the LOEE (MWh per year) for both a standard test system (the IEEE RTS) and for a distributed system consisting of 284 identical 12 MW units. In order to simulate the effects of conflict on the systems, the mean time to repair for each unit was increased and the reliability indices recalculated. The model finds that the distributed system is up to five times less sensitive to this measure of systematic conflict. This supports our hypothesis that DG systems will have improved reliability over centralized systems when operated under adverse conditions. Current and future work is focused on model improvements and extensions, including the relative economics of centralized versus distributed system under stress.

Even without considering the benefits of robustness under conflict conditions, a DG system offers substantial costs savings. Based on current IC engine cogeneration, systemwide savings of 20–30 percent can be realized, dependent on matching between the heat to power characteristics of the DG technology and demand. To realize these savings, local load aggregation is required, but with the cooperation of distribution utilities, this is easily achieved. Under widespread use of DG, capital and maintenance economies of scale would be expected to increase system cost savings. If existing energy infrastructures are in place, transition issues including stranded costs are expected.■

Endnotes:

1. For example, the ice storm of 1998, which hit Quebec, Ontario, New York, and parts of New England, left millions of people without power. In some cases, power was not restored for weeks.

2. The economic impact of any outage will depend on a range of factors, including the area affected, the duration and a host of other factors. As an example, Hydro Quebec's direct losses to its electricity system was estimated at around a half a billion US dollars. Overall economic losses could have been around three times that amount (Hydro Quebec, *Committee of Experts Appointed by Hydro-Quebec's Board of Directors: Report on January 1998 Ice Storm*, Montreal, Quebec, July 1998). Similarly, Niagara Mohawk Power Company in New York lost around $100 million due to damage to its equipment (FEMA, 1998). Web site on New York ice storm of 1998, http://www.fema.gov/reg-ii/1998/nyice1.htm, updated March 24, 1998).

3. One aspect of this issue we have not examined is the relationship between the size of the system and the impacts of either extreme weather or conflict. A larger system should be less vulnerable to extreme weather simply because of the redundancy in the system and the localized nature of impacts. On the other hand, a large system may be *more* vulnerable to deliberate attack because of the larger number of potential targets and reliance on key nodes, which can be identified and attacked (e.g., key transmission lines).

4. *Physical Vulnerability of Electric Systems to Natural Disasters and Sabotage* (Washington, DC: Congress of the United States, Office of Technology Assessment, June 1990, OTA-E-453, at 15–6).

5. H.L. Willis, and W. Scott, *Distributed Power Generation: Planning and Evaluation* (New York: Marcel Dekker, Inc., 2000, at 15).

6. H.L. Willis, and W. Scott, *Distributed Power Generation: Planning and Evaluation* (New York: Marcel Dekker, Inc., 2000, at 67–70).

7. An industrial country is likely to have backup generators for their hospitals and can easily install the same for water supply. These backup systems will not keep the economy humming, but will save lives. In a less industrialized country, the absence of these localized adaptations will cost lives.

8. See also M. Gordon, *Crisis in the Balkans: The Overview; NATO Air Attacks on Power Plants Pass a Threshold*, The New York Times, May 4, 1999, on the NATO bombing of Yugoslavia and Energy and Defense Project ''Dispersed, Decentralized, and Renewable Energy Sources: Alternatives to National Vulnerability and War: Final Report''. For the Federal Emergency Management Agency (Contract: DCPA 01-79-C-0320, FEMA Work Unit #2314-F). Washington, DC, 1980 (also available in book form as W. Clark, and J. Page, *Energy, Vulnerability, and War: Alternative for America* (New York: W.W. Norton & Company) on the hampering of Germany's industrial production in World War II.

9. Unless otherwise noted, information from World Bank, *Technical Annex: Bosnia and Herzegovina Emergency Electric Power Reconstruction Project*, Energy Sector Unit, Bosnia and Herzegovina Country Unit, Europe and Central Asia Regional Office, Washington, DC, Report No. T-6804-BiH, July 10, 1996 and World Bank, *Bosnia And Herzegovina: 1996–1998 Lessons And Accomplishments: Review of The Priority Reconstruction and Recovery Program and Looking Ahead Towards Sustainable Economic Development*, Report Prepared for the May 1999 Donors Conference, Washington, DC.

10. Figures provided are for 1990 production. In general, the hydropower plants (which have a capacity equal to the thermal plants) had an average yearly output of 6,900 GWh, which could provide ~54 percent of the electricity supply.

11. In this case, the natural gas supply came from Russia. It should be noted that when the conflict involves a primary fuel supplier, it might be difficult to ensure supply regardless of whether the system is centralized or distributed. There is a difference depending upon the fuel. Coal (which is more likely to be domestic) can be feasibly stored for a season. On the other hand, with natural gas, it may be possible to initiate a degree of fuel switching if another fuel (e.g., diesel) is available.

12. See, for example, Energy and Defense Project, 1980, OTA, 1990, and J. Plummer, *Energy Vulnerability* (Cambridge, MA: Ballinger Publishing Company, 1982).

13. For example, *Critical Foundations: Protecting America's Infrastructures*, The Report of the of the President's Commission on Critical Infrastructure Protection, Washington, DC, 1997.

14. Most notably, see Energy and Defense Project, 1981, and A. Lovins, and L. Lovins, *Energy Policies for Resilience and National Security* (San Francisco: Friends of the Earth, Inc.). For the Federal Emergency Management Agency (Contract: DCPA01-79-C-0317, FEMA Work Unit #4351-C), Washington, DC, 1981.

15. H. Zerriffi, H. Dowlatabadi, and N. Strachan, *Electricity and Conflict: An Evaluation of Distributed Co-Generation as an Economic and Reliable Solution*, 5th International Conference on Technology and Policy Innovation, June 26–29, 2001, The Hague, The Netherlands.

16. Billinton and Li, 1994, at 76–9.

17. Readers are referred to any standard statistics text on using the inverse

of the cumulative distribution function in order to sample from a distribution. This is also reviewed in Billinton and Li (1994).

18. See Billinton and Li (1994), **Appendix A**.

19. Billinton and Li (1994), at 86.

20. *The Role of Distributed Generation in Competitive Energy Markets* (Chicago, IL: Gas Research Institute, 1999).

21. For example, in 1998 The Netherlands had 6 percent national electricity capacity as DG units of <1 MWe, and 35 percent of national electricity capacity as DG units of <50 MWe.

22. The available DG technology in this model is internal combustion (IC) engines.

23. N. Strachan, and H. Dowlatabadi, *A Green-Field System Optimization of Distributed Generation*. THE ENERGY J., 2001, submitted for publication.

24. N. Strachan, *Distributed Generation and Path Dependence*, 5th International Conference on Technology and Policy Innovation, June 26–29, 2001, The Hague, The Netherlands.

25. See Strachan (2001).

26. Model verification: with a population of 12 million in Florida, the discounted cost per person is between $465 and $585 per person per year. This includes industrial energy demands and all network construction.

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