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Prepared for the U.S. Department of Energy
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American Recovery and Reinvestment Act (ARRA)
FEMP Technical Assistance
U.S. Army – Project 214

Analysis of Regulations Associated with Implementation of a Rocky Mountain Secure Smart-Grid

WM Warwick

September 2010

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Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

The potential to utilize emerging smart-grid technologies along with indigenous renewable and other resources to meet the emergency and other power needs of the Department of Defense (DOD) facilities in Colorado and Wyoming is the underlying premise of The United States Northern Command's (Northcom's) concept for a Rocky Mountain Smart-grid. Northcom approached the Department of Energy's (DOE's) Federal Energy Management Program (FEMP) to request technical support to develop this concept further to provide a basis for policies and plans going forward. This task resulted from that request, as did tasks assigned to other organizations.

Northcom's secure smart-grid concept was premised on the concentration of military facilities along the eastern edge of the Rock Mountains critical to national security and defense (the Front Range facilities). Continuity of operations of all or portions of these facilities requires a secure, reliable supply of power. Recent reports by DOD, including the Defense Science Board (DSB) Energy Panel report, "More Fight, Less Fuel," and the North American Electric Reliability Corporation (NERC), "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System" highlight the potential risk to the civilian power infrastructure and consequently to military missions. In addition, these reports indicate potential future threats, and hence power outages, may last far longer than current emergency operating plans and facilities anticipate.

The core concept for Northcom's secure smart grid is the ability to use smart-grid technologies to create a grid-within-a-grid that can provide power to critical military facilities during a prolonged power outage. Northcom envisions a solution that utilizes existing grid infrastructure to wheel power from secure power sources to mission critical DOD facilities. In simple terms, during an emergency, existing energy infrastructure would be reconfigured to provide power to DOD facilities on a priority basis, which may require curtailment of power service to other customers. This "secure" grid would be deployed using smart-grid technologies so that the switch over was essentially automatic. Use of the commercial power grid in this manner presents a number of questions about utility law and regulations and how they may help or hinder the development of a secure smart grid. That is the primary focus of this task.

The approach taken in this task was to address three primary questions:

- Is there any potential for the concept?
- Is it possible to realize that potential?
- Is it practical to do so?

To address the legal and regulatory questions associated with Northcom's proposal it was also necessary to consider technical and economic factors, although evaluation of those issues was covered in tasks assigned to others by FEMP. Accordingly, limited analysis of some of those issues is also included in this report. To the extent information from other tasks was available it was incorporated in this analysis.

In terms of the three critical questions, first, the necessary renewable and conventional resources and transmission infrastructure exist to realize the Northcom's vision for a secure smart-grid. Second, legal authority to implement elements of the secure smart-grid is in place to make this vision at least a possibility. However, there are practical considerations that both cast doubt on its wisdom and suggest other options that may accomplish a similar goal at reduced cost in terms of political good will, economics, and technical complexity.

In brief, there is a class of risks that can be accommodated by existing and planned efforts by utilities and others. There is another class of risks that have a low probability of occurrence but will likely have a catastrophic impact, leading to prolonged, grid-wide outages. It is unclear how the secure smart-grid Northcom envisions would fare in that situation. This suggests two courses for Northcom and/or DOD going forward. The first is to work more closely with industry to ensure it is addressing Northcom's concerns as industry hardens its systems against threats that it believes it can resist. The second is to refocus its vision for a secure smart-grid in recognition that the "worst case" threats could so damage the commercial power infrastructure that it could not support Northcom's proposed grid-within-a-grid. This would require a much smaller secure smart-grid and potentially little more than the base-specific microgrids and base power "islands" that are currently being studied and deployed. One option is to minimize the potential legal and regulatory conflicts by working with a single utility, Colorado Springs Utilities (CSU), on a solution that would meet the secure power requirements of the four military facilities served by CSU.

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Description of ARRA Program

The Federal Energy Management Program (FEMP) facilitates the Federal Government's implementation of sound, cost-effective energy management and investment practices to enhance the nation's energy security and environmental stewardship. To advance that goal and help accelerate agencies' progress, FEMP works to foster collaboration between its Federal agency customers and the U.S. Department of Energy (DOE) national laboratories.

In 2009 and 2010, FEMP has utilized funding from the American Recovery and Reinvestment Act of 2009 (ARRA) to facilitate Federal agency access to the broad range of capabilities expertise at the National Laboratories. Funds were directed to laboratories to assist agencies in making their internal management decisions for investments in energy efficiency and deployment of renewables, with particular emphasis on assisting with the mandates of the Energy Independence and Security Act of 2007 related to Federal facilities and fleets.

FEMP provided major DOE laboratories with funding that will allow them to respond quickly to provide technical advice and assistance. FEMP applied a simple vetting and approval system to quickly allocate work to each of the laboratories in accordance with FEMP-provided funding. All assistance provided by the laboratories was in accordance with the requirements of Federal Acquisition Regulation (FAR) Subpart 35.017 and the labs' designation as "Federal Funded Research and Development Center" (FFRDC) facilities.

Introduction

This report was funded by the Department of Energy's Federal Energy Management Program (FEMP). The Federal Energy Management Program's mission is to “facilitate the Federal Government's implementation of sound, cost-effective energy management and investment practices to enhance the nation's energy security and environmental stewardship.” Although this document discusses legal issues it is not the intent to provide legal interpretations or advice. The discussions herein cannot be relied on as legal opinions.

The concentration of military facilities on the plains east of the Rock Mountains, including Northcom facilities, are critical to national security and defense. Continuity of operations of all or portions of these facilities requires a secure and reliable supply of power. Recent reports by the Department of Defense (DOD), including the Defense Science Board (DSB) February 2009 Energy Panel report, “More Fight, Less Fuel,” and the North American Electric Reliability Corporation (NERC), “High-Impact, Low-Frequency Event Risk to the North American Bulk Power System” (June 2010) highlight the potential risk to the civilian power infrastructure and consequently to military missions. In addition, these reports indicate potential future threats, and power outages, may last far longer than current emergency operating plans and facilities anticipate.

In response to this risk, Northcom staff began exploring options. It appeared to Northcom staff that there are sufficient renewable and other resources in this region to meet mission critical military power needs and that the potential for smart-grid technologies may enable the development of a mission critical grid-within-a-grid. In concept, smart-grid technologies could be used during an emergency to automatically reconfigure the commercial power grid to ensure reliable supplies of power to mission critical DOD facilities.

Northcom’s secure smart-grid concept depends on indigenous renewable and other resources to meet the emergency and other power needs of DOD facilities, transmission and distribution capabilities to wheel power from generating sources among DOD sites, and so-called “smart” technologies that enable the automatic reconfiguration of the grid to serve as a secure grid and to manage loads and resources to maintain system stability. Northcom expects this potential exists within Colorado and Wyoming because:

- Pacific Northwest National Laboratory (PNNL) previously identified significant wind and other renewable resources at two installations, Fort Carson and FE Warren AFB, some of which have been developed;

- Preliminary assessments by FEMP of potential for a large-scale solar development that could serve multiple installations by wheeling the power from a central site;

- Potential for and development of smart-grid capabilities by the major utilities in these states;

- And the presence and need for a continuous supply of power to operate critical DOD facilities, in particular, those that support the mission of Northcom.

Northcom approached DOE's Federal Energy Management Program (FEMP) to request technical support to develop this concept of a secure smart-grid further to provide a basis for policies and plans going forward.

FEMP provided funding for a number of assistance activities to support Northcom's technical assistance request, including this task. The primary focus of the task is identification of legal and regulatory barriers that may prohibit realization of Northcom's secure smart-grid concept, specifically with respect to the legal ability of installations and DOD to wheel power among the various locations to optimize the development and use of renewable resources. In the course of the study it was necessary to also consider technical and economic issues although evaluation of those issues was assigned to others by FEMP. This report briefly discusses various topics to provide a foundation to understand the complexity of legal and regulatory issues as they relate to deployment of a secure smart-grid by Northcom and to analyze potential options going forward.

Background

The premise for the Rocky Mountain Smart-grid is that military access to secure power is critical to national defense and that the commercial power grid is sufficiently vulnerable to failure that it presents an unnecessary risk from potentially cataclysmic natural disasters and from attack by hostile agents. There are numerous examples of prolonged power outages from natural disasters to support this view, including the Northridge earthquake and hurricane Katrina. There is also ample evidence of attempts by outsiders to disable commercial power systems, mostly in classified sources, but also including market manipulation that led to the rolling blackouts and brownouts that roiled the California grid in 2000. These risks have attracted the attention of the leadership of government's primary military and domestic institutions, including the Departments of Defense (DOD), Homeland Security (DHS), and Energy (DOE).

The Defense Science Board report, "More Fight, Less Fuel" (the DSB report) specifically highlighted this risk to DOD's military mission. The report suggested the potential risk presented a clear and present danger that required immediate action. The recent North American Electric Reliability Corporation report, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System" (the NERC report), provides an "industry-research institution" perspective on the potential risks and assessment of industry and government preparedness that places DOD's concerns in broader context. This paper draws heavily on the these two sources as well as the author's participation on the DSB energy panel that drafted the DSB report, which included a number of classified briefings on risks, attack modes, and mitigation measures.

The United States Northern Command (Northcom) is a unified combat command created after the terrorist attack on September 11, 2001. Its mission is to protect the United States homeland and support local, state, and Federal authorities. This role is critically dependent on secure power for all Northcom elements and its civilian counterparts. Accordingly, Northcom approached the Federal Energy Management Program (FEMP) office for technical assistance evaluating ways it could address this problem. Its request proposed, in concept, utilization of emerging smart-grid technologies to create a secure grid within the larger commercial bulk power system that would contain within it indigenous power resources sufficient to support the missions of Northcom and seven or eight nearby military installations in Wyoming and Colorado.

The smart-grid proposal raised a number of questions. At the outset, it proposed a possible solution without a precise definition of the problem. Specifically, what kind of outage protection is needed? Interconnection-wide outages have different implications that localized ones. Further, what is the expected outage duration? Again, preparations for short term outages are very different than for long-term ones, especially because long-term outages impact other infrastructures that may become critical if lost. It also has implications for what level of services may be available to the non-military community; a community that is vital to the routine operation of military facilities. Secondarily, it isn't clear that a smart-grid is the best solution to the general proposition that the vulnerability of the bulk power system presents a security threat to the mission of Northcom and DOD.

If we accept the underlying premise of the proposal, namely there is a problem and a smart-grid is the solution, additional questions arise. The major one being is there any potential for such a concept. This question has two major parts. The first is technical; the second legal. The technical questions have to do with the capabilities of smart-grid technologies and the timeline for their deployment in light of the grid risks of concern to Northcom, as well as the challenge of directing the flow of power to locations Northcom considers critical, to the potential exclusion of all other customers. The second question has to do with how Northcom could impose this concept on the commercial power system in the face of the fact that the ownership of the bulk power system is in private hands and the operation of that system is governed by a myriad of Federal, interstate, state, and local laws and regulations. The primary focus of this report is the second set of questions; however, it is unrealistic to address those questions without addressing technical issues raised in the first set of questions. Because the technical questions are outside the scope of the task at hand, they are only considered briefly in the following sections.

Issues 101

To facilitate the substantive discussion in this report, it seems prudent to provide background information on the power grid, utility regulation, Federal rules regarding procurement of utility services, and the smart-grid. Each will be described briefly to provide a common base of understanding for the heart of the report. As such, the descriptions may lack details that the author doesn't believe are relevant that others may.

Power Grid 101

The US utility system has been described as the world's largest machine. It has also been suggested as the greatest invention of the 20th Century. It should qualify on both counts given its geographic scope, technical complexity, and level of reliability. The current North American power grid is composed of three parts, or "interconnections;" Western, Eastern, and Texas. Each operates independently from the others in terms of control, although they all follow the same operating standards to ensure interoperability of electrical devices and equipment.

The bulk power system did not spring forth in its present form. In fact, the terms used to describe it, "power *grid*" and "bulk power *system*," are misleading. Instead of being a homogenous "system" that operates as a uniform whole, it is in fact, a series of inter-related and interdependent utilities that, while independent, are operated cooperatively. Each utility has its own characteristics, which makes seamless operation a distant ideal. The need for a single, integrated grid is unclear given the high level of reliability the current mode of operation provides. The trigger for consolidated operation of independent utilities emerged as isolated utility systems merged into larger utilities and as large generating stations located remotely from primary load centers were interconnected through high voltage transmission lines. Interconnection led to interdependence and thus to cooperative management of ever larger systems of generation and transmission despite different ownership. The fundamental vulnerability comes from this interdependence and the *ad hoc* evolution of the system. Specifically, independent evolution of utilities has resulted in planning and operating practices, including equipment and transmission and distribution system voltage standards, that are incompatible. This complicates after-the-fact adoption of uniform equipment and standard practices to secure the grid. By the same token, the diversity across the system may prove beneficial if it prevents a common mode of attack or failure across utilities; however that benefit is far from clear.

The US power system is among the most reliable in the world. A typical utility has a level of reliability in excess of 99.9%, or three "9"s. Most large utilities are closer to 5-9s most years. Three-9s is the equivalent of less than 9 hours of outage per customer per year. This is an average, which means some customers may be without power for days, while others may have no interruptions. Outage risks increase for customers served at lower voltage levels and in remote areas. This reflects the fact that lower voltage lines are subject to more disturbances because lines are in areas where vegetation, erratic drivers, and lack of maintenance are more common. Successively higher voltage levels on the system require taller and more robust towers that are generally further away from vegetation and roadways. They are also specifically engineered to withstand environmental and other hazards. Most DOD facilities are served off the high voltage system, which is inherently more reliable. However, many DOD facilities are in remote locations, where the length of the power lines present other reliability problems such as undetected access, risks from wildfires and landslides, vandalism by hunters, and even animal attacks.

The US power grid owes its high level of reliability to the way the system is planned and operated. Planning considerations include redundant elements to prevent outages from "single mode failure" and diversity to hedge against risks to elements with common features, such as source of fuel or equipment design or manufacturer. Redundancy is achieved by incorporating a "reserve margin" in system design. Conservative planning practices are mirrored in system operations, where reliability margins are dynamically adapted to specific circumstances. For example, hot weather reduces the efficiency of thermal generating plants and the transmission capacity of power lines. As a result, system operators "de-rate" those facilities, which then requires operators to find supplemental generating resources and alternative transmission routes. During extreme events system operators may resort to temporary measures, such as reducing system voltage levels (so called "brownouts") or curtailment of loads either selectively or through what are called "rotating blackouts," where power to whole segments of the power grid may be without power on a rotating basis. Operators may curtail all power flows if these measures do not work or the situation has the potential to damage critical equipment, blacking out the entire system.

Within the three interconnections, there are roughly 100 "control area operators" with the responsibility to maintain the integrity of the power system under their control. Control areas generally coincide with the boundaries of large utilities. In some areas, independent system operators (ISOs) operate multiple utility power grids as a single system. Operators coordinate with each other within each of the three major interconnections. When adverse events occur within one of the regional or sub-regional coordination areas, system operators within the area or adjacent to it may act to isolate the problem by disconnecting connections to the problem area. The 2003 Northeast Blackout is a case in point. The problem originated in one utility service area, but alarmed operators in adjacent areas. Thos operators attempted to protect their system by disconnecting from the utility with the problem. As a result, the entire interconnection began to go unstable and both manual and automatic control actions led to a cascade of disconnections and automatic generator shut downs. The Eastern Interconnection did not suffer from any major equipment damage as a consequence. However, fully restoring service after a regional blackout takes days because of the restart sequence for large power plants, particularly nuclear and coal units. The ability to trigger this kind of response in the power system through hostile acts is the concern at the heart of both the DSB and NERC reports.

The US power system includes a "merchant" function that is overlain on the "engineering" system, the system managed by control area operators. A detailed discussion of that function is unnecessary; however, a brief description of major elements is needed to understand the additional vulnerabilities it may create and how these may be amplified in a smart-grid.

Wholesale power markets have been deregulated in the US. This means non-utilities can build and operate generation and transmission, and brokers and traders can sell power and transmission access. They do so for commercial (profit maximizing) purposes in contrast to utilities that have obligations to provide reliable power to retail consumers at "affordable rates." Accordingly, coordination of utility and merchant generation is now managed through wholesale power (and transmission) markets. Because transmission and generation are substitutable, there are independent markets for each. These markets establish schedules for the operation of generation and transmission, which are coordinated through independent grid operators or through transmission agreements that provide buyers and sellers of power access to the entire transmission system within a market or coordination region.

Power and transmission is exchanged through a variety of market mechanisms. For the purposes of this paper, what is critical is that these market mechanisms require "transparency." That means market participants must have access to the status of the entire market, including loading on each transmission line segment and the current or forecast operating levels for scheduled generation and transmission. This information is needed to prepare competitive bids and to review power purchase options among market participants. However, it also provides hostile agents with information that can be used to reveal vulnerabilities in the power system, such as over-subscribed transmission routes, or to manipulate system operations by rigging market bids. This flaw was exploited by a handful of California market participants in 2000 and 2001. Rogue traders were able to disrupt the power grid by entering extreme bids and/or withholding generation from the market. It was in many ways a blueprint for how to disrupt both a power market and the economy of a state; a state with an economy that ranks in the top 10 globally.

The "rules" for how the smart-grid will operate are not yet written; however, the extension of the wholesale market to all consumers is one end point. For example, pilot efforts are underway to allow retail customers to bid load curtailment against generation (curtailing a load is an alternative to generating power to serve it). As electric vehicles penetrate the market, their owners could bid power from their batteries into the grid as generation or as an ancillary service. Consumer level transactions are expected to be small individually, compared to bids in the generation market; however, in aggregate they may be equivalent. Because they will also accumulate up to the bulk power market through the distribution system, disruptions are less likely to have the same impact as wholesale market manipulation. Nevertheless, a retail market platform may provide entry points to grid operations that allow manipulation of the bulk power system by simultaneously executing a command that would be disruptive, for example, offering power from all electric vehicles connected to the grid and then not providing it.

The key points from this discussion for this paper are that the US power system is presently highly reliable primarily because industry practices that have been adapted to the current range of natural events and some caused by operator errors, accidents, and malfeasance. The NERC report concluded that against this range of events, current responses are adequate; however, these events fall into the low to moderate "impact" category (op. cit., page 26). The NERC report did not address threats posed by markets or by new, smart-grid technologies or operating practices. Both the NERC and DSB reports focused on "high" risks from "low frequency" events that would either result in multi-mode failures or that would overwhelm industry's ability to respond. These risks are in contrast to current industry practice to protect against single-mode failures. At issue for this paper is the question; "Can smart-grid technologies do any better?" To address that question, we must look at the risks identified in the NERC report.

Risks to the Grid 101

The NERC report focuses at a high level on a handful of risks; adversarial physical attacks, pandemics, and magnetic pulses of various kinds. These are broadly representative of the range of potential catastrophic risks to the grid. The discussion to this point assumes normal operations, which includes planning for and recovering from off-normal events. The power system has suffered numerous failures. Catastrophic failures on the scale envisioned in the NERC report have been primarily caused by natural events such as hurricanes, regional ice storms, and large earthquakes that have almost instantly destroyed critical infrastructure across a wide area. Generally, these events are limited in duration. After the event passes, the focus shifts to service restoration. Industry experience with catastrophic events has provided information regarding what system components are likely to be damaged, and most utilities have stockpiles of critical equipment to replace these components. Mutual aid agreements are also in place that allows one utility to borrow "spares" and staff from other utilities if its own stock of spare components, staff, or equipment is insufficient. As a result, the NERC report (op. cit. page 26), concluded, "The redundant design of the bulk power system provides a high degree of inherent resilience and protection against many threats in the low and intermediate range." However, it goes on to conclude, "A highly-coordinated and structured cyber, physical, or blended attack … could result in long-term (irreparable) damage…" It further states that, "… a coordinated attack would involve an intelligent adversary with the capability to quickly bring the system outside the protection provided by current planning and operating practices. An outage could result with the potential to affect a wide geographic area and cause large population centers to lose power for extended periods." This contrasts to "normal" outages, where the damage is geographically isolated and non-recurring. These normal conditions allow for routine operation of the grid outside the outage area providing a base from which the affected area can be serviced and power quickly restored.

Of interest to this paper is the kind of threats NERC identified, their likely impact on the system, potential mediation and restoration actions that can be taken to remediate them, and finally, the potential role smart-grid technologies and practices may play to address the concerns embodied in the Northcom proposal.

The threats NERC identified were characterized as "high impact, low frequency." In other words, these would be threats that would be potentially devastating but occur with such low probability that they would be difficult to anticipate and expensive to protect against. Briefly summarizing the NERC report, the primary threats are:

- Coordinated physical attack
- Coordinated cyber attack
- Hybrid attack (both physical and cyber)
- Pandemics
- Geomagnetic disturbance (GMD)
- Electromagnetic pulse (EMP).

Each of these attacks has unique characteristics in terms of impact area, recurrence risk, duration, and ability to respond.

> Coordinated physical attacks would mimic the kinds of damage anticipated from other catastrophes; however, these attacks would cause more damage to more critical components of the system, including potentially to generators that are typically protected during natural disasters by existing protective systems. The NERC report notes that industry is already moving to stockpile more critical spare components and recommends further efforts to reduce the up to 2-year lead time for some critical components (op. cit. page 14).
>
> Coordinated cyber attacks could take myriad forms, from manipulation of system operations (or market) software, use of computers to create off-normal conditions and/or prevent protective responses, and manipulation of firmware that controls automatic and "smart" equipment such as relays. What all of these have in common is the loss of control by system managers with the likely result of widespread outages and potentially lasting damage to critical equipment including equipment that is not critical itself, but so widely distributed that inability to manage it remotely would prevent timely restoration of normal system operations. The widespread adoption and use of automated and "smart" equipment in lieu of manual operators makes this a particularly difficult threat to protect against. Nevertheless, the Administration and the industry are taking steps to do so. Because the primary benefit of automation has been to provide system operators with more information and greater control over unsupervised and remote components on the system, the primary liability is the loss of that information and control. To that end, the NERC report (op. cit. pages 11 and 38) recommends procedures be implemented that allow system operators to "fly with fewer controls." The report envisions responses that could include allowing an interconnection to separate into autonomous subsystems that could be operated with less oversight, albeit with potentially lower levels of power quality and reliability. This so-called "graceful failure" into "island systems" mirrors a recommendation by the DSB to use military bases as a foundation for "energy security islands." Energy security islands would be self-sufficient in terms of generation to meet indigenous loads so they could operate independent of the bulk power system for an extended period, for at least 6 months in the DSB's vision.
>
> Pandemics present risks somewhat similar to those that would result from a shortage of staff to address either a physical or cyber attack. Many of the functions of utility operations are embodied in a small pool of uniquely trained individuals. If a large fraction of those individuals are incapacitated or dead,

normal functioning of the system will be impaired. As the report notes, because a pandemic isn't selective, the risk extends to the entire supply chain supporting utility operations including fuel delivery, maintenance of command and control systems and other support services. Pandemics also have a potential multiplier effect because an illness of one family member may curtail the activities of other family members through quarantines or the need to provide home care.

The NERC report finally lists a collection of risks based on electromagnetic interference. Electromagnetic interference (EMI) results from the fact that the power system is composed of conductive wires, including those providing power and communications to end uses. This acts like an antenna that interacts with magnetic fields to produce electric current and other effects that can damage equipment. The risk has increased over time as reliance on semi-conductor based equipment has increased and as a result of the increased sensitivity of that equipment to minor fluctuations in power quality. The EMI risks discussed include geomagnetic disturbances (GMD) and electromagnetic disturbances (EMP). Of these, GMD may be the most problematic because it is naturally occurring (from solar storms) and has affected the US grid at least twice in recent history (March 1989 and October 2003). The risks from EMP are primarily man-made because EMP can be generated from nuclear blasts and other devices. Two types of EMP were considered in the NERC report; high–altitude EMP (ironically called HEMP) such as would be produced from an above-ground nuclear explosion and intentional EMI (IEMI). Unfortunately, there is utility experience with EMP from both of these sources. Of the two, HEMP is the most destructive and most difficult to protect against. The destruction comes from EMI generated by the explosion. The higher and larger the blast, the wider the area affected. Interconnection-wide impacts are foreseeable and these could result from a single blast. Adversaries capable of launching multiple missiles could affect all three interconnections effectively shutting down power for all of North America. IEMI is more focused, but it could be projected from a radar equipped van that would be essentially undetectable. As a result, while the impact may be localized, deployment at multiple sites could impact a wide area.

The potential scope and scale of impacts from these risks is sobering. The NERC report indicates (op. cit. page 9), "As mitigating options are further considered, it is also important to note that it is impossible to fully protect the system from every threat or threat actor. Sound management of these and all risks to the sector must take a holistic approach, with specific focus on determining the appropriate balance of resilience, restoration, and protection." This observation helps set the stage for an assessment of the technical capabilities of smart-grid technologies and the ability of these to respond to the risks identified by and in the NERC report.

Smart-grid 101

The notion of adding intelligence to the power grid pre-dates the term "smart-grid." As a result, there are numerous notions of what the smart-grid embodies. Rather than debate the merits for alternative definitions, we will use the characterization provided by DOE's SmartGrid.gov web site:

> What is the smart grid? An electrical grid is a network of technologies that delivers electricity from power plants to consumers in their homes and offices. A smarter grid is different in a few important ways. First, it uses information technologies to improve how electricity travels from power plants to consumers. Second, it allows those consumers to interact with the grid. Third, it integrates new and improved technologies into the operation of the grid. A smarter grid will enable many benefits, including improved response to power demand, more intelligent management of outages, better integration of renewable forms of energy, and the storage of electricity.
>
> The smart grid is an automated electric power system that monitors and controls grid activities, ensuring the two-way flow of electricity and information between power plants and consumers—and all points in between. Up and down the electric power system, the smart grid will generate billions of data points from thousands of system devices and hundreds of thousands of consumers. What makes this grid "smart" is the ability to sense, monitor, and, in some cases, control (automatically or remotely) how the system operates or behaves under a given set of conditions. In its most basic form, implementation of a smarter grid is adding intelligence to all areas of the electric power system to optimize our use of electricity.

The key features of this definition are:

- Two way information and communication flows (and associated communication networks),

- Data flow between essentially all elements of the power network from generators down to end uses, and potentially within end uses. In other words, lots of data and information from lots of sensors, each of which is attached to the power grid or associated communication system.

- Real-time processing and response and potentially, decentralized "decision making" – taking the utility operator "out of the loop".

Deployment of the smart-grid to date has reflected a mix of approaches either as pilot efforts or "first steps" along a path. Two notable pilots are the Bonneville Power Administration "Oly-Penn" project and the Boulder (Colorado) SmartGridCity. These offer contrasting approaches to the critical issue of control. Both projects used "smart meters" that provide the utility with much more information about consumption in a timelier manner. This is the backbone of the connection between the consumer and the grid because it provides the pathway for the two-way communication and data flows that are its hallmark. In the Oly-Penn study, this pathway was used to provide consumers with choices about what appliances to operate at what costs on a time varying basis using a market mechanism. The Boulder pilot employed appliance load control as well, but real-time curtailment was directed by the utility rather than the consumer. The locus of the control decision, consumer or utility/grid operator seems to be a distinguishing feature of early smart-grid deployments. Empowering consumers requires that they be knowledgeable about how their consumption affects the grid. In a word, it requires "smart" consumers. A more utility/operator-centric approach requires less interaction from consumers with the grid. This is more in line with current, relatively passive demand-response programs; programs that can be implemented without grid or consumer "intelligence."

There are a number of lessons that can be drawn from these two examples for the purposes of this report. First, the smart-grid means different things to different people, utilities, regulators, and manufacturers. Second, a deployment where actual interaction is limited to utility defined options likely provides more opportunities to monitor and control cyber threats than one like the Oly-Penn study that use a multi-participant market exchange mechanism. Third, large-scale deployment of even the backbone of a system, the smart meters and associated communication system as in the SmartGridCity project, will be expensive and take years. It won't happen overnight. In other words, implementation of a smart-grid solution to address the Northcom energy security concern may not be timely. Furthermore, the smart-grid makes extensive use of communications systems. This could increase vulnerability to the catastrophic threats noted in the NERC report. Specifically, communication systems present additional targets for physical and cyber attacks and they provide additional antennas that can be affected by EMI. Finally, management and maintenance of these systems will require more and specialized manpower that is vulnerable to a pandemic. Thus, the smart-grid may increase the risks Northcom is trying to address, and deploying it as part of their response to these threats may undermine Northcom's initial objective.

Utility Regulation 101

The discussion to this point has considered technical topics. As noted previously, the operation of the power system and consumer access to that system is covered by Federal, interstate, state and utility regulations and laws. The Supremacy clause of the US Constitution holds the Federal government above state and local laws. That would normally invalidate the effect of local utility laws on the government; however, Congress directed Federal agencies to be deferential to state utility laws (40 USC 591). This is often a larger barrier to Federal power supply innovation than technology. These laws and regulations are also the primary focus of this task. The Congressional restriction in 40 USC 591 is as follows:

> **40 USC 591. Purchase of electricity**
> **(a)** General Limitation on Use of Amounts.— A department, agency, or instrumentality of the Federal Government may not use amounts appropriated or made available by any law to purchase electricity in a manner inconsistent with state law governing the provision of electric utility service, including—
> **(1)** state utility commission rulings; and
> **(2)** electric utility franchises or service territories established under state statute, state regulation, or state-approved territorial agreements.
> **(b)** Exceptions.—
> **(1)** Energy savings.— This section does not preclude the head of a federal agency from entering into a contract under section 801 of the National Energy Conservation Policy Act (42 U.S.C. 8287).
> **(2)** Energy savings for military installations.— This section does not preclude the Secretary of a military department from—

(A) entering into a contract under section 2394 of title 10; or
(B) purchasing electricity from any provider if the Secretary finds that the utility having the applicable state-approved franchise (or other service authorization) is unwilling or unable to meet unusual standards of service reliability that are necessary for purposes of national defense.

The customary interpretation of this provision is that a Federal facility may not purchase electricity from any source other than the local utility with exclusive rights to serve that customer unless it is allowed either by the utility or under state law, such as in a deregulated state. This interpretation is reflected in Federal and DOD acquisition regulations. This interpretation would govern what could and couldn't be done to implement Northcom's smart-grid concept in the near term. It would also suggest a plan of action going forward, namely to work with local utilities within the existing legal framework or to request changes in the governing laws and regulations at the state and Federal level. The laws and regulations of interest with respect to 40 USC 591 are only those covering retail electricity service; in other words, the ability of facilities covered under Northcom's smart-grid concept to produce, procure, and wheel power. The statute doesn't limit Federal facilities from adopting smart-grid technologies or other measures to mitigate potentially catastrophic grid outages or from development of power projects on DOD lands.

This interpretation may be customary; however it appears to ignore the exceptions noted in (b) especially the exception for DOD. These alternative interpretations have not been widely embraced due to the potential consequences of violating this law, specifically, from the misuse of appropriated funds. The consequences for misuse of funds could be dire especially as they apply to the contracting officers who ultimately have to sign-off on any purchase. In other words, for DOD, there appears to be a choice to pursue the exemptions allowed under (b) or acquiescing to the customary interpretation to avoid arousing the ire of local utilities and potentially Congress. It is worthwhile to review some of the history behind 591 to better understand Congressional concern

There are over 3,000 electric utilities providing service to US retail customers. Generally, each has a specified service area within which it has an exclusive obligation to provide service and right to do so. This monopoly over retail power services is limited by state utility laws and regulations and standards adopted by the individual utility. These 3,000 utilities fall into one of two categories; government regulated or self-regulating via another elected body. The first category includes utilities that are owned as stock companies or possibly sole proprietorships, called investor-owned utilities (IOUs). Service terms and rates for IOUs are regulated by the state in most cases. Some utilities that cross state boundaries are regulated as holding companies at the Federal level, although each state they serve in has other regulatory rights. There are roughly 100 IOUs, and they provide power to over 75% of the population. They also sell power to many of the remaining utilities. Those remaining utilities include municipal utilities, rural electric cooperatives, and other entities that may be chartered by the state, such as irrigation districts, economic development districts, and county-based utility districts. These self-regulated utilities tend to be smaller than IOUs and have service areas defined by political subdivisions. They are typically governed by individuals elected from their member customers rather than state regulators; at least as far as service terms and rates are concerned.

In addition to the investor-owned and self-regulated utilities, there is a category of utilities that are owned by a state or the Federal Government. Generally these government-owned utilities operate as “power administrations” or “power projects” generally with a name that reflects their origin, such as the Colorado River Power Authority. Power administrations were typically established for multiple purposes, one of which was to provide lower cost power to select classes of customers, often including other government agencies. The Front Range facilities are in the service area of the Western Area Power Administration (WAPA), which provides power from federally owned and operated hydropower facilities in the western US (except for the Pacific Northwest).

The provision of retail service from IOUs is governed by state law. Access to alternative power supply sources is allowed in states that have deregulated electricity supply. Roughly half of the states have adopted legislation to deregulate, although active retail power markets are primarily confined to the Mid-Atlantic States, Texas, and roughly 10% of the customers in California. Even in these states, competitive market terms and conditions are still regulated by the state, although prices are not. Colorado and Wyoming have not deregulated.

Self-regulated utilities can adopt rules and regulations governing retail sales as they see fit, within the constraints of state law. Generally, that means they could allow customers to procure power from alternative sources unless there is a state law or constitutional prohibition. The governing law in Colorado is as follows (from the Colorado Revised Statutes, CRS):

> **CRS 40-1-103 (part). Public utility defined**
> (1) (a) (I) The term “public utility”, when used in articles 1 to 7 of this title, includes every common carrier, pipeline corporation, gas corporation, electrical corporation, telephone corporation, water corporation, person, or municipality operating for the purpose of supplying the public for domestic, mechanical, or public uses and every corporation, or person declared by law to be affected with a public interest, and each of the preceding is hereby declared to be a public utility and to be subject to the jurisdiction, control, and regulation of the commission and to the provisions of articles 1 to 7 of this title.
> (2) (a) Every cooperative electric association, or nonprofit electric corporation or association, and every other supplier of electric energy, whether supplying electric energy for the use of the public or for the use of its own members, is hereby declared to be affected with a public interest and to be a public utility and to be subject to the jurisdiction, control, and regulation of the commission and to the provisions of articles 1 to 7 of this title.
> (b) (I) Paragraph (a) of this subsection (2) requiring regulation by the commission shall not be applicable to a cooperative electric association which has voted to exempt itself from regulation pursuant to the provisions of section 40-9.5-103.

CRS 40-9.5-201 (part). Definition of service territories
The general assembly hereby finds and declares that the provisions of article XXV of the Colorado constitution allow the public utilities commission to establish exclusive service territories for utilities as provided in article 5 of this title and that it has been the policy of the state of Colorado to establish exclusive service territories for cooperative electric associations. The general assembly further finds and declares that, if a cooperative electric association has been granted an exclusive service territory that is within a municipality that operates an electric utility or within an area annexed by a municipality that operates an electric utility, the municipality has taken private property and shall pay just compensation for the electric distribution facilities and certificate of public convenience and necessity of the association located within the municipality. Therefore, it is declared to be a matter of state-wide concern and to be the purpose of this part 2 to establish a procedure to be followed when the certificated service territory of a cooperative electric association is included within a municipality that operates an electric utility or within an area annexed by a municipality that operates an electric utility.

From this it is clear the state of Colorado has claimed the right to establish exclusive utility service areas for the provision of electric service to retail customers. All of the military bases being considered for the Northcom smart-grid receive some or all of their power from a utility with a state regulated service area, although some of the bases receive some power from WAPA. WAPA power is low cost, but insufficient to meet all of the needs of each base. In that case, the base receives the balance from one or more local utilities based on the service area of the base's connection to the power grid. The regulated IOU in this area of the Front Range bases is Xcel Energy. It serves Buckley AFB. The self-regulated utilities vary by base, although most of the Air Force facilities are served by Colorado Springs Utility (CSU). Fort Carson receives a small amount of power from WAPA and the balance from CSU. A remote part of the base is served by a rural electric cooperative.

Utility regulation in Colorado is provided by the Public Utilities Commission (PUC). It was formed as a Railroad Commission in 1913 and assumed the regulation of utilities in 1914. Cooperative utilities were regulated by the commission from 1961 until 1983 although some remain regulated by the choice of their members. The commission has not had jurisdiction over municipal utilities since 1983. Therefore, the applicable regulations as they apply to Colorado facilities flow from the PUC for customers of Xcel Energy and the boards of the individual cooperatives and municipal utilities for the rest.

The governing law in Wyoming is as follows (from Title 37 of the Wyoming statutes – WS - in part):

CHAPTER 1 - General Provisions

37-1-101. Definitions.

(vi) “Public utility” means and includes every person that owns, operates, leases, controls or has power to operate, lease or control …

(H) None of the provisions of this chapter shall apply to …

(VI) To the generation, transmission or distribution of electricity, or to the manufacture or distribution of gas, or to the furnishing or distribution of water, nor to the production, delivery or furnishing of steam or any other substance, by a producer or other person, for the sole use of a producer or other person, or for the use of tenants of a producer or other person and not for sale to others. Such exemptions shall not apply to metered or other direct sales of a utility commodity by a producer or other person to his tenants.

…

(II) Any cooperative electrical generation and transmission association operating in interstate commerce whose rates are not regulated by the Wyoming public service commission.

Definition of service territories

Wyoming statutes: 37-7-102. Lands need not be contiguous; benefits to exceed damages and costs; must be cheaper as single district.

The lands proposed to be included in any power district need not be contiguous, provided that the benefits of the proposed work in each part will exceed the damages from and costs of said proposed work in each part; and provided, further, that the court shall be satisfied that said proposed work can be more cheaply done if in a single district than otherwise utility.

Rather than attempt a lay interpretation, the findings in a recent (June 25, 2010) case; *Nordic Ranch*, Docket No. 80024-1-WI-09 can speak to this. This case was about a dispute over rates for water service; however, the findings of fact are universal for utility service in the state. Selected findings are as follows:

Legal standards applicable in this case

55. W.S. § 37-1-101(a)(vi)(E) states that:
(v) “Public Utility” means and includes every person that owns, operates, leases, controls or has power to operate, lease, or control:
(E) Any plant, property or facility for the supply, storage, distribution or furnishing to or for the public of water for manufacturing, municipal, agriculture or domestic uses, except and excluding any such plant, property or facility owned by a municipality.

In *Bridle Bit Ranch Co. v. Basin Electric Power Cooperative,* 118 P .3d. 996, 1011 (WY 2005) the Wyoming Supreme Court found Basin Electric was not a public utility because "Basin does not supply electricity 'to or for the public' as contemplated by the governing statute.” In that case, Basin Electric only supplied electricity as a wholesaler to distribution cooperatives who then supplied electricity to or for the public.

…

58. In *Krenning v. Heart Mountain Irrigation District,* 200 P.3d 774, 783 (Wyo. 2009), the Court ruled that an irrigation district is not a public utility, stating, 200 P.3d at 783, "The test for a public utility is not the absolute number of persons it serves, but whether it is devoted to public use." The Court placed importance on several facts, including, [i] that the Irrigation District could only serve those lands that benefited from the irrigation works, [il] that the Public Service Commission had never sought to regulate an irrigation district before, [iii] the Irrigation District did not solicit everyone in the territory, and [iv] there was no reason to believe that the Irrigation District sold any type of products or services to the general public.

…

59. In *Phillips Petroleum Co. v. Public Service Commission,* 545 P.2d 1167, 1171 (Wyo. 1976), the Court discussed the meaning of the phrase "to or for the public" stating, "The words 'to the public' used in the statute regulating public utilities have been defined as 'sales to sufficient of the public to clothe the operation with a public interest.'"

60. W.S. § 37-2-112 is the basic jurisdictional statement of the Commission's utility regulatory power, stating, "The Commission shall have general and exclusive power to regulate and supervise every public utility within the state in accordance with the provisions of this act."

…

63. The Commission establishes certificated areas in which public utilities have the exclusive right --and therefore the obligation --to provide their services. They may refuse to serve outside of their certificated areas, whether or not another utility's area abuts theirs; and the Commission may refuse them the ability to provide service outside of their respective certificated territories. *See, e.g.,* W.S. §§ 37-2-205,37-3-201, 37-15-103 and 37-15-102. *Also see, Utah Power* & *Light Co. v. Public Servo Comm 'n,* 1986 WY 463, 713 P.2d 240 (Wyo. 1986); and *Cody Gas Co. v. Public Serv. Comm 'n,* 1988 WY 9, 748 P.2d 1144 (Wyo. 1988).

A plain reading of the applicable laws (not always the legal one!) leads to the conclusion that the states of Colorado and Wyoming have claimed the right to define utility service areas and to authorize and regulate utilities that provide specific utility services to "the public." Military bases do not qualify as "public utilities" under Colorado law because they do not serve the general public. That isn't sufficient to exempt them from the prohibitions of 40 USC 591 however; because the state has the right to define utility service territories and to grant the utilities within them the sole right to provide electricity.

The application of these laws and regulations to FE Warren AFB is limited by the fact that FE Warren is a WAPA customer. As such, no regulated utility has the "… exclusive right – and therefore the obligation – to provide their services." referred to in "63" above. Instead, it has "wholesale-like" rights to procure power from and through WAPA and to procure supplemental power provided by WAPA. The Findings also make it clear (in "55, 58, and 59" above) that the base can develop resources for its own use and/or purchase power for its exclusive use from a third party operating on base without being covered under Wyoming law as a utility subject to state regulation. WAPA is similarly exempted from state regulation. WAPA is exempt from state utility regulation in any case because it is a Federal entity and thus enjoys the protection of the Supremacy clause in the US Constitution. FE Warren may be subject to regulation under power plant siting regulations depending on the associated environmental impacts, and it would be governed by utility interconnection regulations if it connected to a utility system that was regulated, in other words, one other than WAPA.

With respect to the primary barrier to the wheeling of power from sources other than the local utility, the Front Range facilities in Colorado are limited to supplies provided by the local utility based on the conventional interpretation of 591. At least one utility, Colorado Springs Utility, has been approached to allow third-party power purchases and has cited 591 as a basis for being unwilling to cooperate. CSU was accommodating of the power sale from the on-site photovoltaic system at Fort Carson, although that did not require power wheeling. FE Warren is not encumbered with this restraint, largely due to court decisions which will be discussed further.

Federal Power Procurement 101

Acquisition of electricity by DOD is governed by a variety of laws and regulations each of which provides an installation with different obligations and opportunities. In general, all government procurements are required to be "competitive" under the Competition in Contracting Act (CICA), although there are exceptions for Economy Act transactions and where there are statutory exemptions, both of which apply in the case of power supplied by WAPA. The general procurement authority governing utility services is found under FAR Part 41. It has been interpreted to limit the term of "commodity" power purchases to 5 years and for "services" to 10. Like all contracts, authority for the procurement of electricity resides with the General Services Administration (GSA). GSA has delegated this authority to DOD. DOD has its own "supplement" of the FAR that has both different and additional provisions. DOD also has unique statutory authorities in the electricity area. It has specific authority to develop geothermal energy resources on DOD lands for its own use for power or thermal purposes. This authority resides in 10 USC 2917. It also has authority to procure "energy and fuel" for up to 30 years from "energy production facilities" subject to approval by the Secretary of Defense (SecDef). This authority resides in 10 USC 2922a as mentioned in 591, by its prior number 2394. The referenced US Codes are as follows:

2917. Development of geothermal energy on military lands

The Secretary of a military department may develop, or authorize the development of, any geothermal energy resource within lands under the Secretary's jurisdiction, including public lands, for the use or benefit of the Department of Defense if that development is in the public interest, as determined by the Secretary concerned, and will not deter commercial development and use of other portions of such resource if offered for leasing.

2922a. Contracts for energy or fuel for military installations

(a) Subject to subsection (b), the Secretary of a military department may enter into contracts for periods of up to 30 years—
(1) under section 2917 of this title; and
(2) for the provision and operation of energy production facilities on real property under the Secretary's jurisdiction or on private property and the purchase of energy produced from such facilities.
(b) A contract may be made under subsection (a) only after the approval of the proposed contract by the Secretary of Defense (SecDef).
(c) The costs of contracts under this section for any year may be paid from annual appropriations for that year.

Although 10 USC 2917 allows "development" of geothermal resources on DOD lands, it doesn't provide specific authority to purchase power or thermal energy from a project so developed by a third party. 10 USC 2922a appears to give DOD blanket authority to enter into long term energy contracts subject to SecDef approval. However, it has been interpreted by some Services to be restricted to geothermal energy contracts because of their interpretation of the term "and" in (1). This interpretation asserts that "and" links sections (1) and (2) such that it only grants authority for long term contracts to geothermal energy projects. We are advised that DOD's new Energy staff is reviewing this issue and plans to provide a DOD position on the matter. Regardless, this exception has not been used to request wheeling service to date. It has been used to authorize long-term power purchases from on-site power projects by the Navy. The first of these requests was granted by the project was not developed. Another request is pending SecDef approval.

Analysis

For purposes of this task we will define Northcom's objective is to create a mode of operation of the bulk power system that will allow DOD bases to wheel power from those that have it, including a centralized renewable power source, to those that do not to provide power during a months-long main grid outage. To be effective, this scenario assumes sufficient emergency generation is available at these bases to provide power until the secure smart-grid is operational and can provide adequate, reliable power. The basic architecture of the Front Range Smart-grid consists of the following bases:

- Fort Carson Army Base
- Air Force Academy
- FE Warren AFB
- Buckley AFB
- Peterson AFB
- Schriever AFB
- Cheyenne Mountain AS
- Pueblo Army Depot.

In the original proposal, Pueblo Army Depot would host a large-scale renewable energy project that could provide power to many of the bases. In addition, the existing wind resource at FE Warren AFB would be expanded and that power used to supplement solar power from Pueblo and any other on-base generation. The Depot is being closed and the property transferred from DOD ownership; therefore, it will not be considered further because any resource developed on the site would not be DOD owned. Given the remote location of the Depot to the rest of the installations, it would make more sense to develop a resource closer to the "heart" of the installations, namely in the Colorado Springs area. That resource may not need to be on DOD property. The exclusion of the Depot does not materially affect this analysis or conclusions.

The target installations are served by at least the five local utilities subject to state laws and regulations. In addition, power is provided by WAPA and transmission access is governed by the rules of the Western Electricity Coordinating Council (WECC), an interstate transmission oversight body and security coordinator. Both WAPA and the WECC have rules and procedures governing interconnection to the bulk power system, generation regulation, and wheeling power over the transmission grid. These primarily are requirements for generating reserves, ancillary service provision, and the submission and maintenance of scheduled use of the transmission system.

Current power requirements at the target facilities are summarized in Table 1.

Table 1. Power Requirements and Suppliers for Front Range Facilities

Installation	Utility	MWh/yr	MW ave.	Peak MW
Air Force Academy	CSU	99,700	11	13
Buckley AFB	Xcel	143,000	16	15
Cheyenne Mountain	CSU/WAPA	33,125	4	4
FE Warren AFB	WAPA	26,850	3	5
Fort Carson Army Base	CSU	161,250	18	19
Peterson AFB	CSU	98,600	11	12
Pueblo Chemical Depot	WAPA/Black Hills	9,250	1	2
Schriever AFB	Tri-state/Mtn. View	80,000	9	10

Notes to the table:

Serving utility and peak demand from "Pre-feasibility Transmission Facility Study for 200 MW of Concentrated Solar Power at Pueblo Chemical Depot or Nixon Power Plant," (the Pueblo report) prepared by Duane Torgerson for DOE-FEMP (Sept. 30, 2009). Values are estimates.
Electricity consumption data from draft report, "American Recovery and Reinvestment Act (ARRA) FEMP Technical Assistance: USNORTHCOM Rocky Mountain Installations," prepared by the National Renewable Energy Laboratory – NREL, (undated). Figures were rounded.
MW average calculated from NREL report.
Source of the inconsistency between peak estimate and energy consumption (MWh and MW average) for Buckley is unknown.

Fort Carson hosts a 2-MW solar array and FE Warren AFB hosts three wind turbines with a combined generating capability of 3.2 MW. The Carson solar array makes a 2% contribution to Carson's electricity requirements. The turbines at FE Warren provide 20% of the base's electricity requirements. There is a poor correlation between wind production and the seasonal and hourly demand at FE Warren. As a result, the wind turbines meet or exceed demand during many light load periods (typically in the early morning hours) and the excess production flows to the commercial grid. The 20% estimate only includes power used on-site. Generation at the rest of the sites is minimal. The NREL report cited in Table 1 concluded that only the Air Force Academy, Fort Carson, and FE Warren have potentially economic wind power resources that could provide up to 3%, 5%, and 10% of installation power requirements, respectively. The NREL economic analysis did not reflect the low value FE Warren receives for its excess wind generation currently, meaning that additional wind resource development is likely uneconomic. Similarly, the wind resource on Fort Carson is remote from the cantonment, which will require either new transmission lines to the cantonment or wheeling to the cantonment at additional expense. When these costs are considered, that resource may also be uneconomic.

Economics is not the only criteria that should be considered. The NREL report also looked at total resource potential. Using their data for electricity production from on-site projects incremental production falls short of meeting total installation energy requirements (Table 2).

Table 2. Fraction of Installation Power Requirements that could be met with New Renewables

Installation	Photovoltaic MWh	Wind MWh	Total	MW ave.	Tot RE %
Air Force Academy	1,635	2,353	3,988	0.5	4%
Buckley AFB	1,618	1,080	2,698	0.3	2%
Cheyenne Mountain	1,625	2,122	3,747	0.4	11%
FE Warren AFB	1,552	2,245	3,797	0.4	14%
Fort Carson Army Base	1,687	2,380	4,067	0.5	3%
Peterson AFB	1,655	1,166	2,821	0.3	3%
Pueblo Chemical Depot	1,690	1,289	2,979	0.3	32%
Schriever AFB	1,664	1,327	2,991	0.3	4%

This analysis ignores the coincidence between installation demand and power production. Again, any incremental wind production at FE Warren will likely exceed base demand at the time of production and simply flow onto the commercial grid. Of course, the ability to wheel "excess" generation among bases is part of the secure smart-grid concept. However, even this option cannot be realized using the available on-site renewable energy potential. Based on an analysis of data in the NREL report, the total renewable power resource is only able to meet 4% of total electricity requirements. And, that assumes all of the available energy could be used either on-base or wheeled to other bases. It should be noted that the potential at Pueblo does not include the 200-MW concentrating solar system envisioned in the "Pre-feasibility" report referenced under Table 1.

Based on this analysis, there are two immediate questions that need to be addressed. The first is; Can the resource potential identified in Table 2 be developed consistent with current utility laws and regulations? The second is because the resources available in Table 2 fall short of the needs of the Front Range facilities; Can other resources be developed elsewhere and the power wheeled to the Front Range facilities?

Can on-site renewable resources be developed consistent with current utility laws and regulations?

There does not appear to be any restrictions in state laws preventing on-site development of renewable resources for on-site use. One vehicle for development of these resources is to engage a third party to develop the project and sell the power to the site, typically under a power purchase agreement (PPA). This mechanism has been used by Fort Carson with Colorado Springs Utilities and by NREL with Xcel Energy, a state regulated utility. The lack of objection in these two cases supports this interpretation. Assuming that hurdle has been overcome then the restrictions in 40 USC 591 and the applicability of CRS 40-1-103 may not apply to purchases of power from on-site suppliers. There is a remote possibility a self-regulated utility other than CSU could object that a PPA arrangement violates its regulations. Based on the information in Table 1, that would only affect Schriever AFB. Although on-site development of resources for use on-site may be allowed, the site and its development partners still have to comply with state siting requirements and utility interconnection requirements.

Can renewable resources be developed by DOD and the power wheeled among Front Range facilities?

This is a much more complicated question. As with the previous question, the first test is; “Is it allowed by the serving utility?” If the answer is “no,” then we need to know if there is an exemption to 40 USC 591.

The case of FE Warren is the easiest. FE Warren is primarily served by WAPA. It already purchases supplemental power through a competitive power supply contract. Clearly there is no applicable state or utility limitation on its ability to generate power on-site, sell power from on-site resources, or purchase power from off-site suppliers.

Colorado’s primary utility laws are representative of utility laws in many states. They give the state the right to define utility service areas and utilities within them exclusive rights to provide power. As was just noted, that right has not been asserted for sales from on-site projects owned by third parties by Xcel and CSU. In practice, both Xcel and CSU have asserted that they have an exclusive right to provide electricity within their service territories, and have cited 40 USC 591 to prevent Federal agencies from attempting to purchase power from other suppliers. Thus far, no Federal facility has forced the issue; nevertheless, this raises a series of questions about the utilities’ self-serving interpretation of 40 USC 591 and exemptions thereto.

Two opinions bear on this question. The first is how 40 USC 591 may really apply, given no utility has tried to enforce its provisions and federal agencies have been sufficiently intimidated when utilities raise it as an issue. The second uses a conservative interpretation of 40 USC 591 but explores exceptions therein and some other options.

Does 40 USC 591 Apply?

Congress adopted 40 USC 591 as Section 8093 in the DOD Appropriation Act of 1988. It was inserted in response to a jurisdictional dispute over utility service won by the Air Force (Black Hills v Weinberger). At issue was the right of the AF to procure power competitively in an area where utility service areas were undefined. Ultimately the US Supreme Court found in the government’s favor. The case was revisited subsequently in West River Electric v. Black Hills in which West River Electric asserted it had exclusive rights under state law to provide service to the air base, and therefore a supply contract with Black Hills should be voided. The Federal district court declared that because the air base is a federal enclave state law does not apply. This decision was appealed and the Eight Circuit found that the assertion of state jurisdiction over power purchases was insufficient to overturn the body of federal procurement law requiring competition:

> We conclude that Section 8093, as part of an appropriations bill, is insufficient to defer the exclusive grant of federal jurisdiction, nor was it intended to amend the extensive body of federal procurement law which established that federal agencies must use full and open competitive procedures in the procurement of their property and services.

The key finding is that the basis for the initial suit was an assertion of state supremacy with respect to utility services. The Court found that Congressional direction to be deferential wasn't sufficient to offset the public benefits to be had from competition. Also of interest is the view of the Court that highlights the concern Congress intended to address is the revenue loss by utilities for investments made on behalf of the customer. This is a reference to Black Hills v Weinberger, where the Eighth Circuit concluded:

> We do not believe that Congress intended to prevent the use of competitive procedures in this situation. Had Congress wanted to mandate that state franchise law governs the determination of when a utility is in a "sole source" position, it could easily have done so. Congress has specifically provided that agencies may use other than competitive procedures if a statute requires that procurement be from a specified source, 10 USC 2304 (c)(5). However, Congress has never enacted a statute requiring that the United States purchase utility service from local franchise utilities.

Presumably in response to this decision, Congress adopted 8093 by statute as 40 USC 591. Or did it? The controlling language in 8093 and 40 USC 591 is identical. Therefore, the conditions noted by the Eighth Circuit above appear to be valid still. Otherwise Congress would have done what the Court said it did not do, which was explicitly state that state utility law should guide power purchases, not the Competition in Contracting Act (CICA). Specifically, 40 USC 591 does not contain any additional language that directs Federal agencies to procure power solely from local utilities with the service area franchise. Decisions of the Eighth Circuit are only binding within its jurisdiction. Nevertheless, It appears DOD facilities can use this decision to assert their right to procure power from other sources based on the fact power markets are deregulated so competition is available and therefore required under CICA.

The Eight Circuit's decision still appears to leave installations that take service from another source vulnerable to law suits for lost revenues for facilities or power supplies dedicated to their service, so-called "stranded costs." An example of how this might work is provided by the experience of Edwards AFB in California. Edwards AFB enrolled in "Open Access" when California deregulated its retail power market. It subsequently signed a supply contract with Enron that was breached when Enron declared bankruptcy in the midst of the California energy crisis in 2000 and 2001. The State of California stepped into this breach to provide power on long term contracts at prices more reasonable than otherwise available at the time. While this restored order to the California energy market, it also saddled the State with an obligation to pay for power supplied to local utilities. Once market order was restored Edwards asked to return to the competitive power supply market. In order to do so Edwards negotiated an exit fee with its local utility that would compensate the utility for its share of the high-cost power contracts. It was not obligated to pay for planned resources not yet constructed for example or for transmission and distribution facilities because it intended to use those under posted tariffs to transport power from competitive suppliers to the base.

If 40 USC 591 Applies, Then What?

A restrictive interpretation of 40 USC 591 still allows DOD facilities flexibility to explore options to utility power service. It specifically allows the following exemptions:

- Energy savings under 42 USC 8287
- Energy purchased under 10 USC 2394 (now 2922a)
- Purchases when the local utility is unwilling or unable to meet "unusual standards" for service reliability for national defense as determined by the Secretary of Defense (SecDef).

Each of these is recognized as legitimate exceptions in the FAR (Part 41.201). The FAR calls out "2394" for military departments in 41.201 (d)(2)(ii) as distinct from other agencies not covered by "2394" in 41.201 (d)(3)(i-iii). However in 41.201 (e) it notes that such transactions be "consistent with section 8093 [now 40 USC 591]" as determined by legal consultation with serving utilities and/or state regulatory commission *prior* to acquisition of any power or utility service. This view is reinforced in FAR Part 52(a) which largely parrots the language in 8093; "Section 8093 of Public Law 100-202 generally requires purchase of electricity by any department, agency, or instrumentality of the United States to be consistent with State law governing the provision of electric utility service…" This is also reflected in the DOD FAR Supplement (DFAR) Purposes, Authorities, Issuances (PGI) in PGI 241.103 which indicates "Section 8093 of Public Law 100-202 specifically precludes the Federal Government from expending appropriated funds to purchase electricity in a manner inconsistent with State law and regulation" for "energy commodity" procurements. These regulations do not over-ride Federal law or Court decisions that clarify Federal law, so as a practical matter these should not be interpreted to preclude competitive acquisition of electricity, but to do so within the exclusions provided in the law as supported by legal review of the specific circumstance.

There may be other options. One is to obtain service competitively in a manner that is not "inconsistent with state law governing provision of utility service including" commission rulings and territory agreements. There are a myriad of commission rulings that can be mined for other exceptions. Because the apparent purpose of 8093 was to prevent stranded costs, one option would be to agree to reimburse the former utility for those costs, which would be consistent with ratemaking practice to prevent cross-subsidies. Per the FAR's "consistency" language, that would be part of the discussion with the local utility and/or state regulatory body. If either or both rejected the proposal to reimburse the utility for stranded costs, it would appear the government could proceed at the risk of being sued for stranded costs at a later date. It could also proceed based on an identified national defense purpose that was endorsed by the SecDef.

Another option would be for the facility to seek "wholesale" status thereby exempting itself from state regulatory requirements altogether. That option is included in the FAR

(41.201 (d)(3)(iii) subject to the "consultation" clause (41.201 (e)). In other words, a facility could inform its current retail power supplier that it intends to seek service as a wholesale customer. If the utility agrees, it would be free to do so.

Wholesale power transactions are subject to Federal, not state, regulation through FERC. FERC regulations provide "rules *for* the road" but not "rules *of* the road." In other words, it does not provide specific guidelines for wholesale market operation and it does not provide instant enforcement when it appears the rules of the road have been violated. Instead, these details are left to regional owners and users of the grid. This leads to a great deal of variability across the nation, including within all three interconnections. As a general matter however, wholesale power and transmission providers must post operating schedules and adhere to them or be subject to penalties. One requirement is for suppliers of power or transmission to also provide reserves appropriate to their market activity. This requirement is enforced through designated reliability coordinators with specific enforcement authority. What this means in practice is a wholesale power supplier must carry "insurance" on its transactions, which increases the cost of the power or wheeling transaction. This would apply to DOD if it were to become a power producer on the wholesale power grid. Retail utility suppliers may impose similar requirements on DOD's self-generation as well. In other words, providing sufficient generation to meet the roughly 80-MW load of the Front Range facilities will likely require about 100 MW of generating capability, some of which will need to be in "spinning" or "operating" reserve (which means it will be running at a suboptimal level to be able to rapidly increase output if needed). Reserves and other needed ancillary services can be "optioned" rather than "owned" by DOD; however, "ownership" would be required to ensure the reliability of a secure grid. As a result, this option may not be practical or economic.

In summary, installations have several options they could pursue depending on how aggressive they want to be asserting Federal supremacy claims or using exemptions granted in 591 or in asserting rights as a retail-turned-wholesale customer. Regardless, it is likely an installation that tries to bypass the local utility will be asked to repay the utility for "stranded costs."

Practical Considerations

It is now time to consider the practicality of the Northcom secure smart-grid concept. This requires answers to a series of related questions. The first has to do with adequacy of on-site generation because developing on-site generation faces the fewest potential barriers.

From the NREL renewable assessment (Table 2), it is clear there isn't sufficient renewable resource potential on the installations, individually or collectively, to provide sufficient power to meet the full requirements of all sites during a prolonged grid outage. Consequently resources will have to be imported from off-site or lands set aside on one or more of the installations for new generation, be it renewable or conventional, economic or not. And power will need to be wheeled among bases. This was all envisioned in the original Northcom proposal. However, the review of legal, regulatory, and procurement barriers indicates there are significant challenges to enabling the necessary resource supply and wheeling service. In addition, there are significant technical barriers to the transmission of power among DOD bases.

The following map (Figure 1) from 2007 Tri-state Cooperative Integrated Resource Plan illustrates some of the technical challenges of wheeling power among the Front Range facilities.

A "TOT" is a transmission boundary across which transmission is monitored for power quality and reliability reasons because it represents a choke point or constraint in the system. Wheeling power across a TOT represents a larger challenge than wheeling within an area bounded by TOTs. The bulk of the Front Range facilities are in the Eastern Colorado control area. The exception is FE Warren, which is located off the map north of Fort Collins. It is one or two "TOTs" away, depending on the transmission path. Also evident from the map is that the primary generating resources serving Denver, the major load center, are around Pueblo and northeast of Denver. Power flows from those locations towards Denver. These power flows have priority access to transmission capacity by the utilities to serve "native load" (retail) customers.

What is not evident from the map, but which is from the report it is taken from, is that transmission capacity in this area is severely constrained and will be even more so as new renewable resources are developed to comply with Colorado's renewable portfolio requirements because the best wind and solar resources are in the eastern and southern parts of the state. This means it will be difficult for DOD to obtain firm transmission capacity to wheel power among DOD facilities. Firm capacity would be necessary for reliability and to enable a secure grid within the existing bulk power system.

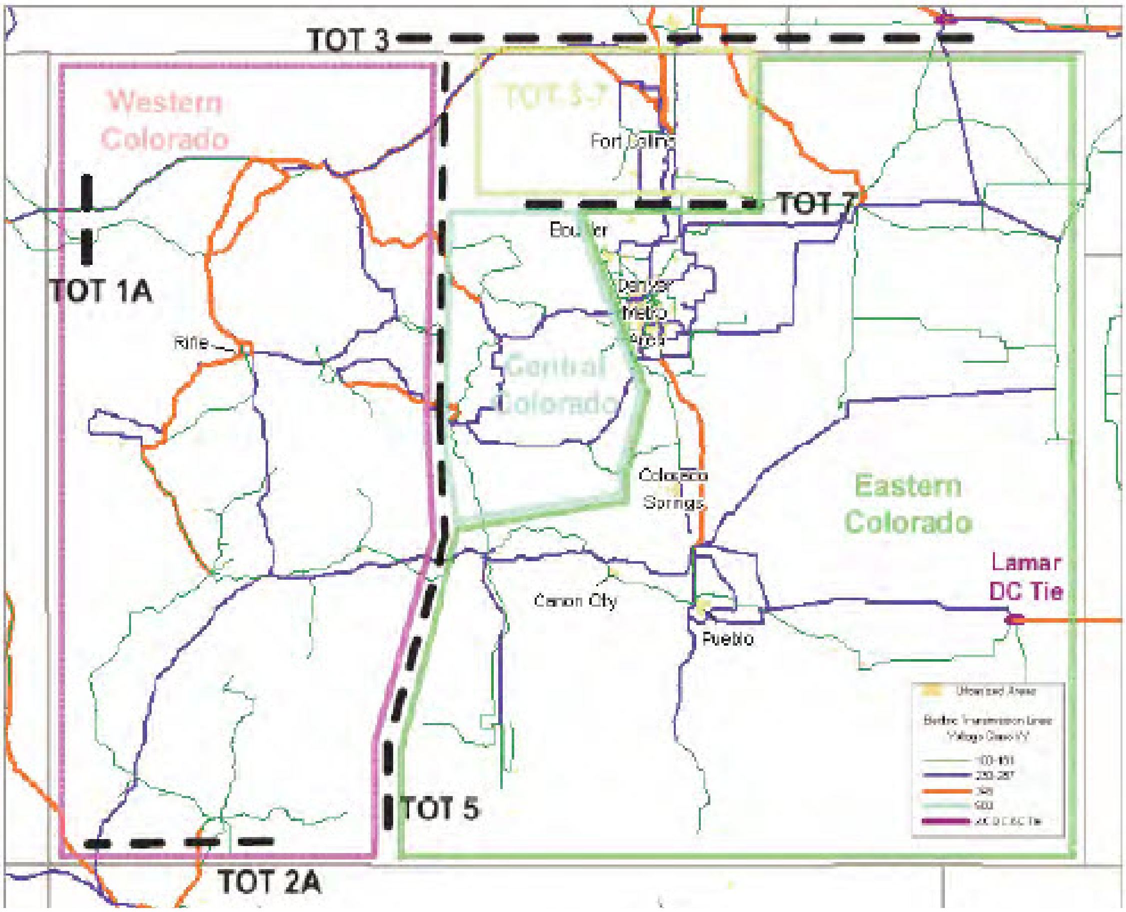

Figure 1. Map Showing Transmission Constraints Most Affecting Tri-State (from Tri-State Cooperative Integrated Resource Plan, Tri-State Electric Coop)

The next question is what role a smart-grid might play to free up transmission capacity, to address potential threats to the grid, or to manage a DOD grid-within-a gird. Smart-grid technologies may provide local utilities greater flexibility in how they manage during outages and respond to Northcom's concerns. Clearly this is the vision of the DOE Smart-grid Stakeholders, who envision the smart-grid being able to achieve the following:

- Self-healing from power disturbance events
- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st Century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets

- Optimizing assets and operating efficiently.

Controlling loads during peak periods offers one of the surest pay offs from “smart” technologies. Dynamic management of loads will enable curtailment of end uses that are little valued by consumers compared to others. For example, water heaters could be automatically turned off on late summer afternoons to accommodate higher priority cooling loads. Practices such as this can free up transmission capacity for other users, including creating firm transmission capacity for a DOD smart-grid. However, transmission capacity is so constrained in this region already that smart-grid technologies may be needed simply to prevent forced curtailments, brownouts, and blackouts.

Just as smart-grid technologies may free up capacity during peak periods, they have the same capability to control power demands to meet available generation during situations where critical generation is not available, such as after a range fire knocks a critical transmission line out of service. It isn’t clear that this capability will be of value during the catastrophic events highlighted in the NREC report. That is because consumer-level smart- grid technologies primarily focus on load management and integration of customer-level generation. A wide-scale grid outage would disable access to that capability until and unless the grid is restored. In other words, a major grid outage would disable access to these “smart” resources. At present, the primary focus of smart- grid technologies is on the benefits they provide to the bulk power system. Making the bulk power system “smarter” has benefits even if it doesn’t filter down to the consumer level. Increased intelligence in the bulk power system will enable operators to “fly with fewer controls” as recommended in the NERC report. Over time this capability may evolve to the customer level to allow decentralized operation of clusters of customers who may be isolated during grid outages. That capability isn’t available today, in part because customer-level generation isn’t widespread. Even if it were, it would result in many independent “island” grids that were isolated from each other, and therefore unable to share power between clusters. Adoption of electric vehicles is expected to bring changes within 10 to 15 years that will enable that kind of operation. This illustrates the final point; namely penetration of smart-grid technologies will take years and without a high adoption rate, smart-grid technologies will be of little value.

DOE’s Grid 2030 schedule for deployment of smart-grid and other emerging technologies is as follows:

By 2010	By 2020	By 2030
Customer "gateway" for the next generation "smart meter", enabling two-way communications and a "transactive" customer-utility interface Intelligent homes and appliances linked to the grid Programs for customer participation in power markets through demand-side management and distributed generation Advanced composite conductors for greater transmission capacity Regional plans for grid expansion and modernization	Customer "total energy" systems for power, heating, cooling, and humidity control with "plug&play" abilities, leasable through mortgages "Perfect" power quality through automatic corrections for voltage, frequency, and power factor issues HTS generators, transformers, and cables will make a significant difference Long distance superconducting transmission cables	Highly reliable, secure, digital-grade power for any customer who wants it Access to affordable pollution-free, low-carbon electricity generation produced anywhere in the country Affordable energy storage devices available to anyone Completion of a national (or continental) superconducting backbone

From DOE smart grid website (www.oe.energy.gov/smartgrid.htm)

It envisions most of the *capabilities* needed to manage loads at the end-use level will be largely in place by 2020; however, the penetration of new technologies will depend on the replacement of legacy appliances and equipment as well as voluntary adoption of "smart" appliances and equipment much earlier than 2020. The normal replacement cycle for many residential appliances and equipment is longer than 10 years, meaning wide-scale deployment of smart-grid *functions* may be delayed 15 or more years from now. Is this soon enough for Northcom?

Fortunately, the smart-grid doesn't depend on full deployment of all capabilities to provide immediate and significant benefits. In addition to smart meters, the smart-grid includes installation of wide-area measurement systems (WAMS) and other sensors that will be used to increase automated controls and inform grid operators so they are better able to respond to off-normal events and minimize consequences from them. That should speed restoration and increase their ability to operate the grid under adverse conditions, including supporting critical facilities. It may still require brute force options in the near term.

In the near term, absent widespread adoption of many smart-grid technologies, the brute force approach to creating the Northcom grid-within-a-grid for the DOD Front Range facilities would require generation that now flows into Denver to bypass the city enroute to Buckley AFB and FE Warren AFB. This is illustrated by Figures 2 and 3 which show the location of the Front Range facilities (Figure 2) and a "close-up" of the Eastern Colorado control area transmission network (Figure 3).

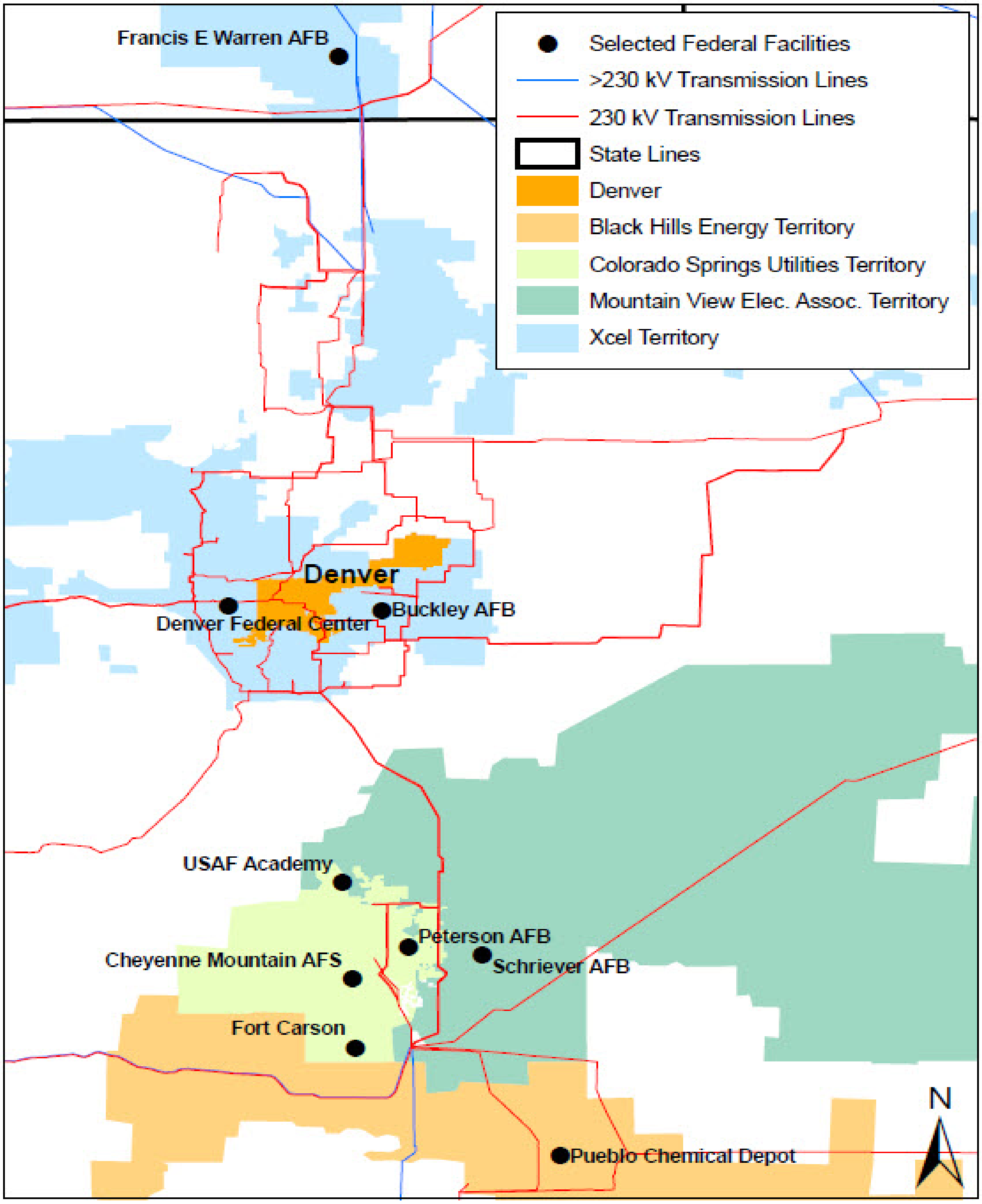

Figure 2. Front Range Facilities, Local Utilities, and Major Transmission Lines (from Tri-State Cooperative Integrated Resource Plan, Tri-State Electric Coop)

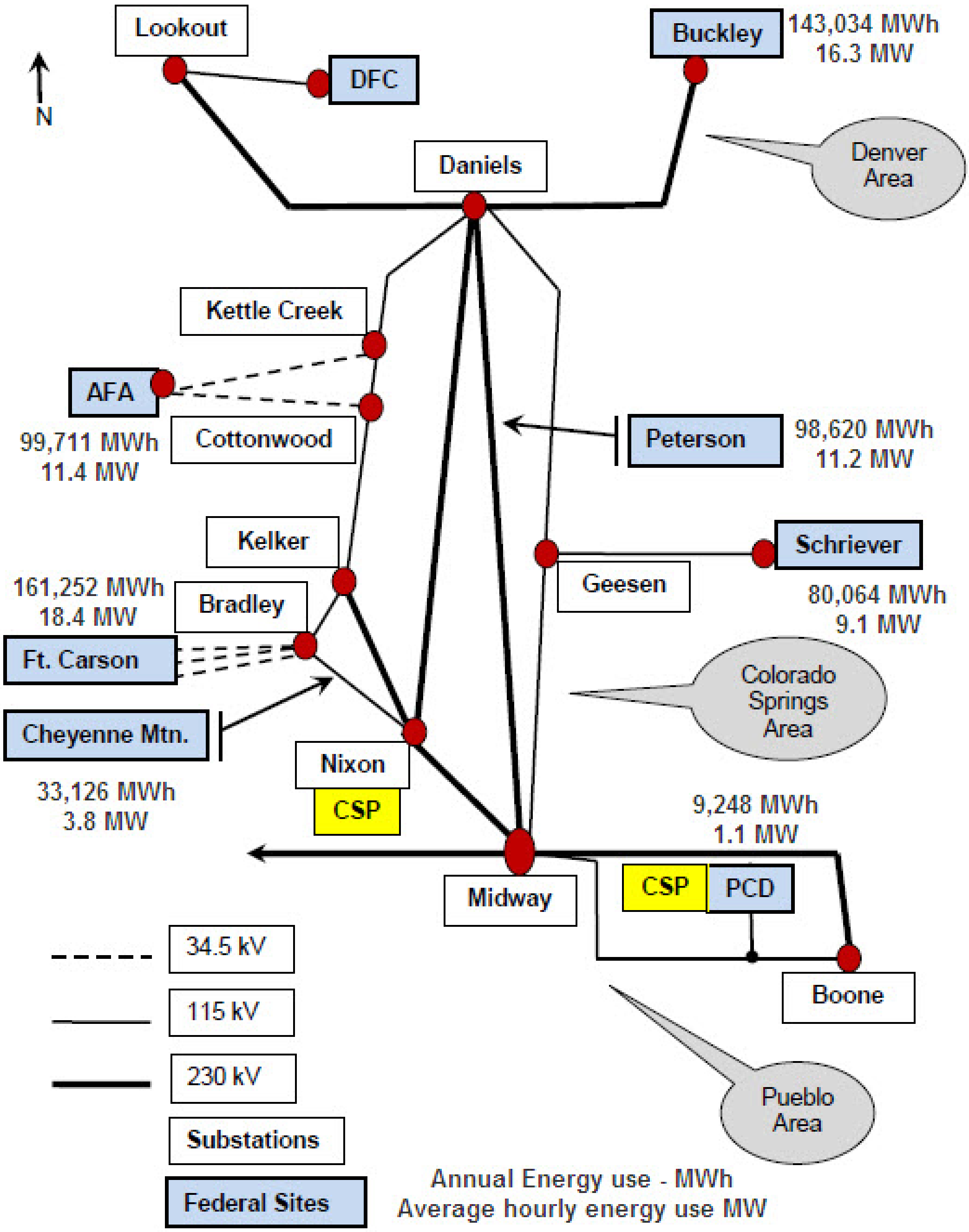

Figure 3. Colorado Springs Area Grid with Federal Facilities (load data as noted for Table 1).

Major generating facilities are located south of the Midway substation in the Pueblo area (see Figure 3). Colorado Springs Utilities serves its loads from generation located in its service area and from facilities at the Nixon power plant and substation. Generation from Pueblo also feeds into the Nixon substation enroute to the Daniels substation to serve loads in the Denver area including Buckley AFB. FE Warren is not provided with power from any of these facilities, although a transmission path to it exists through Fort Collins (see Figure 1). For FE Warren to be integrated into a DOD grid, the existing service configuration would have to be changed to divert power from Fort Collins and Denver to create a straight path between FE Warren and Colorado Springs. That may be acceptable in an emergency, but it would be a difficult option to justify to the public and elected officials unless they were facing or in the throes of such an event. This reality complicates planning for this eventuality and deployment of Northcom's initial vision for a DOD grid that includes all seven or eight DOD facilities in this region.

This leaves us with the final question, namely will a smart-grid help enough against the threats that concern Northcom, the DSB, and NERC? As noted previously, the high-impact, low-frequency events NERC evaluated are essentially so comprehensive in origin and impact that they cannot be guarded against and will be difficult to recover from. Because the worst of these, the EMP events, will also affect "smart" technologies, a smart-grid will do little to limit the scope or severity of risk.

The DSB was more concerned about coordinated terrorist attacks, both cyber and physical. The worst physical attack scenario would couple the attack to use of weapons that would induce panic in the population and make it hazardous for personnel to enter an area to restore the grid and any other critical infrastructure. Such an attack on an urban area could be particularly devastating because most urban areas are crossroads for infrastructures that serve a large area, such as ports, freeway interchanges, pipeline hubs, and so on. If an attack resulted in the depopulation of an area there would be few loads for "smart" technologies to control. Nevertheless, increased intelligence would enable operation of facilities in "hot zones" remotely, which would facilitate more rapid restoration of critical infrastructure in those areas.

The DSB considered attacks to be more likely in remote areas where detection is more difficult and freedom of movement more certain. Attacks in remote areas could be devastating, despite the lower concentration of assets, if the targets are attacked repeatedly after each restoration. Smart-grid technologies would help under these more conventional threats by speeding identification of affected equipment and potentially providing advance notice of intrusion that would trigger the safe shutdown of equipment to prevent wider scale damage or to facilitate interdiction.

Summary and Conclusions

Northcom approached FEMP with a concept for a grid-within-a-grid that could be activated during severe grid disruptions using smart-grid technologies to provide secure power to DOD facilities for mission critical functions. Ideally, the "secure, smart-grid" would enable DOD facilities to share indigenous power resources, including abundant renewable generation, across the central plains of Colorado and Wyoming to power bases from FE Warren AFB in the north to Pueblo Chemical Depot in the south. This system would address a number of risks that could result in potentially catastrophic grid outages for prolonged periods of time.

As a concept, the specific risks and system scope and architecture remain to be defined. FEMP agreed to provide technical assistance to Northcom to flesh out their proposal, including this task to identify and address potential legal and regulatory hurdles implementation might face. The approach taken was to address three broad questions. First, is there any potential for such a concept? Second, is it possible to implement the concept given what is known about the current state of utility laws and regulations and other technical issues? Third, is it practical based on the analysis of various utility laws and regulation and other technical considerations? In other words: Is implementation of the concept reasonable? Finally, is the concept the best way to address Northcom's fundamental concerns about securing power for critical missions in light of the range of risks? Are there other options that may be better?

Although the primary focus of the task is legal and regulatory, the lack of specificity required analysis of some of the other elements of the proposal and inclusion in this report of background discussions of selected technical aspects of utility operations and smart-grid technologies. With respect to potential for this concept, the analysis found that there are abundant renewable and conventional resources in the target area that could support DOD operations for a sustained period of time if the grid could be reconfigured during a major outage. Few of these exist on DOD installations, which would require their procurement from off-site sources. There are legal and regulatory barriers that may complicate procurement of power from sources other than the local utility. However, these could be overcome through negotiation and/or by changes to state and Federal laws, utility regulations, and potentially, through emergency orders from the President. Therefore, it is possible to implement the secure, smart-grid concept, although changes in laws and regulations, if necessary, present formidable political challenges. Further, "smart" technologies are being deployed on the power grid; however, the pace of deployment is not rapid. Sufficient intelligence may not be available *at the consumer level* for 10 years at the soonest with a 20-year horizon more realistic. Nevertheless, the adoption of smart-grid technologies *in utility operations* could provide utilities with the capability to implement the grid-within-a-grid function using brute force methods that would simply curtail power service to customers outside the target transmission corridor. Most likely, that would result in limited or no service to the bulk of the Denver metro and Fort Collins areas. As a practical matter, it is unlikely the current laws and regulations that present barriers to this concept can be changed in a timely manner. It is also unlikely local utilities would entertain making the necessary changes to accommodate a secure grid-within-a-grid in the event its utilization is ordered by the President or others. Because there are insufficient renewable and other indigenous resources on DOD bases to provide the quantity of power needed to fully support all of DOD's current power needs, utility cooperation will be required, upfront, to confront current technical constraints and applicable utility regulations in a collaborative manner.

More importantly, the most severe threats to the grid are ones that are all but impossible to protect against. They include events such as pandemics and solar storm induced electromagnetic interference that are of such scope and scale to make prevention impractical. Moreover, a solar storm would affect "smart" technologies as much as existing infrastructure. Although both pandemics and/or solar storms are infrequent events, they have historic precedents. In other words, they are real and may be more real risks than those imagined from adversaries. Threats of that order leave few options other than to adapt to the specific situation as best as possible. That strategy may lead away from Northcom's initial concept because a grid that is all but destroyed won't be able to provide much service no matter how "intelligent" it may be, or more accurately, may have been.

Based on this analysis, there are two possibilities. The first is to confront restrictive utility laws and regulations head-on through new Federal legislation. Success in that effort would then allow the substantial investment in new generating resources and other enabling technologies, probably by the Federal Government, not the local utilities. Because some of the required legislative changes have been attempted by DOD before, prospects for timely resolution are dim. This effort may take two or more Congressional cycles because of the lack of familiarity key Congressional committees have with the issues. Specifically, most national and homeland defense committees do not deal with utility issues so they will need to be educated to advocate for the required changes. DOD has limited ability to educate members of Congress and their staffs, while those likely to be opposed to the required changes have more flexibility to counter DOD's tutorials. The expected pace of DOE's smart-grid program could accomplish much of what Northcom desires if its 10-plus year timeframe is acceptable. This suggests a second strategy, which is to more actively guide the DOE program to ensure it enables the grid-within-a-grid capability during extreme events and to promote standards for the design of smart-grid components and operating systems that are hardened against the kinds of threats envisioned by Northcom, such as those in the NERC and DSB reports. This too may occur naturally as DOD erects the necessary internal institutional frameworks to bring focus to its concerns in this area, which it has been doing since the release of the DSB report. With these activities already underway, the final question would seem to be what role Northcom will play in each.

Is there a Plan B?

Another option is to work collaboratively with local utilities within the constraints of existing utility laws and regulations on a more restricted vision of a secure, smart-grid. Northcom's concept for a secure smart-grid has merit despite the challenges in the previous summary. Implementation deserves further consideration in a more limited manner. As Figure 2 illustrates, most of the Front Range facilities are clustered around Colorado Springs and most of those are served by Colorado Springs Utilities. It is also obvious that FE Warren AFB is an outlier. Finally, Pueblo Chemical Depot is being closed via the Base Relocation and Closure (BRAC) process. That process typically disposes of surplus DOD properties to local governments. It is very difficult to reverse that process to retain DOD control once it has been initiated. As the previous analysis indicates, there are significant technical and legal/regulatory barriers to implementation of a DOD grid within the larger bulk power system serving Colorado and Wyoming. These barriers could be avoided through a strategy that treats FE Warren and Buckley AFB individually and both separately from the Colorado Springs area facilities. Pueblo would be ignored given its status in the BRAC process. This approach merits consideration for the following reasons:

- In the Northcom vision, Pueblo's primary role was to host a large-scale renewable generating project that would provide power to the other facilities to its north. Ample land for such a project exists closer to the other Front Range facilities so its inclusion isn't essential. Moreover, the analysis of location options for a central renewable project also considered a site near CSU's Nixon power plant, adjacent to Fort Carson.

- As noted previously, FE Warren already hosts three wind turbines that are capable of meeting its loads some of the time and provides over 20% of its energy on an annual basis. Although land for additional turbines is limited at the base, solar projects could be accommodated and wind resource potential off-site is as good or better. So it is possible to craft an island grid strategy just for FE Warren that could potentially include the adjacent community of Cheyenne Wyoming.

- Buckley AFB is similarly isolated from the Colorado Springs cluster of bases. Unfortunately, the base has limited undeveloped area and is in the suburbs of Denver, where adjacent land is targeted for continued residential development. As a result, the NREL study cited previously and in Table 2 estimates only 2% of Buckley load could be served by renewable resources. Consequently, critical loads on Buckley may be served best through conventional generating resources operating as a microgrid or as a base "island."

- Finally, there is the cluster of five facilities near Colorado Springs; the AF Academy, Cheyenne Mountain, Fort Carson, and Peterson and Schriever AFB. All but Schriever receive power from CSU. Schriever is served by an adjacent utility, but is only 10 miles from Peterson AFB. At least the four facilities served by CSU could potentially be integrated into a secure grid within the CSU system as envisioned by Northcom.

Implementation of base specific microgrids is a subject for another FEMP TA activity for Northcom and won't be discussed further here other than to recommend that solution for Buckley and possibly Schriever. FE Warren is well along the way to being "island capable."

Recommendation for a Secure Smart Grid

The feasibility of creating a secure grid within the Colorado Springs Utilities system depends on the ability of CSU to support the associated loads and its willingness to implement this capability in collaboration with DOD. According to the CSU's 2008 Electric Integrated Resource Plan (EIRP), CSU's peak demand in 2007 was 863 MWs during the summer. It also owned and operated four coal plants and several hydropower facilities in its service area to meet base load power demands.

Coal and hydro facilities are essentially secure generating facilities. Hydropower plants, like all renewable resources, are secure because they have no external fuel requirement and hence no logistical tail that is vulnerable to disruption. Coal plants do require constant supplies of coal as a fuel; however, it is customary to stockpile coal so a plant can operate for periods without resupply. Accordingly, stockpiling coal at each CSU plant or a central storage facility could secure those power resources as well.

In total, CSU's own coal and hydro resources provide nearly 500 MWs of generation, or enough to meet nearly all of CSUs annual *energy (MWh)* requirements. (873 MW of peak demand at a 63% load factor translates into roughly 550 MW demand *on average*.) In other words, CSU is able to rely solely on its own resources to meet most of the *energy* needs of its customers without having to import power from outside its system. Customer demand is not averaged over the year, but varies from season-to-season and hour-to-hour. Accordingly, CSU meets variable power demand from 115 MWs of gas-fired generation. It does import power from outside however, including roughly 50 to 100 MWs of hydropower from WAPA and, about 300 MWs (in 2007) from Front Range Power, a gas-fired plant jointly owned by CSU located at its Nixon power plant site. In the 2008 EIRP, CSU projected demand to increase to approximately 1350 MW peak in 20 years. The Front Range plant has 480 MWs of capacity, which CSU anticipated fully using by 2015 and which could satisfy its growing generating requirements.

In summary, CSU owns and controls sufficient generation within its service territory to meet the needs of DOD facilities, as well as most of the rest of its customer base. It also controls sufficient transmission and distribution infrastructure to wheel power from its primary generating stations to those loads, with the exception of loads on the Nixon-Daniels, Nixon-Midway, and Midway-Daniels lines (Figure 2). Access to Peterson AFB is through the Nixon-Midway-Daniels path. If CSU were operating as an "island" during a grid outage, it may need to sever connections at Nixon to both Daniels and Midway to maintain load-resource balance. However, if it was able to control outgoing circuits at Midway and Daniels to manage load-resource balance, it would be able to serve both Peterson and Schriever (via the Midway-Geesen line). If access to those lines was curtailed for reliability reasons as part of an island strategy, it would most likely provide CSU with a surplus of generating resources within the resulting island (which would exclude loads currently served from the Midway substation). It should be noted that information available for this task was insufficiently detailed to determine what fraction of CSU load was served by specified transmission paths or if the foregoing statements are more than theoretical possibilities. Both would need to be verified including appropriate power flow analyses before proceeding.

System operations in the Eastern Colorado control area could be reconfigured, in theory, to allow CSU to operate as an "island" independent of the bulk power system because it has sufficient indigenous generation to meet its native load, including critical DOD loads. At minimum, it could serve three of its four DOD customers (all but Peterson) and potentially all five area DOD sites (including Schriever) if it could control outflows from Daniels and Midway. The latter option may curtail service to the Denver metro area. Doing so would probably allow Pueblo (including Canon City) to operate as an island along with Fort Collins. This option may be politically untenable other than during a dire emergency, when it would be all but impossible to provide service to Denver in any case. It should be examined nevertheless because it may be necessary to operate in that mode despite the consequences.

CSU's ability to carry its entire load will be limited to plants that are renewable and have secure fuel supplies. That essentially rules out their gas-fired generating stations. If that constraint is coupled with projected load growth, CSU will not be able to serve all loads as an island in the future. In addition, the remaining base load coal plants are unable to cycle up and down to meet daily variations in demand, and the hydropower resources are both limited in size and operating range to play that role if the gas-fired peaking plants are not in service. Consequently maintenance of load-resource balance and reasonable voltage levels would require the ability to manage consumer loads; in other words, *a smart grid*.

It is therefore recommended that Northcom, DOD, or the affected installations served by CSU approach CSU about Northcom's concerns and desire to explore the option of securing the CSU controlled grid, including CSU controlled generation, to provide for "island" operations during grid outages. The options to be explored should include refined analyses of the CSU transmission and distribution system and the DOD loads served by it; potential for deployment of smart-grid technologies to enable both islanding and management of load/resource balance in island mode; potential costs to implement strategies that would enable a secure smart grid to protect DOD facility power needs; and the incremental costs to accelerate smart-grid investments to meet Northcom's and DOD's near-term energy security needs.

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