TransActions

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Utilities Are Toughening Up to Improve Resiliency In the Face of Emergencies

Electric utilities are most often judged by their consumers based upon two criteria; (1) the cost of the commodity and (2) ability of the utility to reliably deliver the commodity. Utility reliability is measured in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These indices are defined by IEEE standards and allow comparison of reliability levels for utilities within the United States or by region. In fact, many regulators have reliability standards that regulated utilities must meet with an impetus for the utilities to be in the top quartile of service reliability. These reliability indices are generally compared with the exclusion of major event days also referred to as major storms. It is difficult to compare the reliability in one year of an electric utility that suffered through an ice storm or hurricane to that of a previous year that did not experience extreme weather events.

Yet history clearly shows that major storms do occur on a periodic basis. **Some would even say the effect of Climate Change will result in more frequent and more severe storms.** So utilities cannot simply look at reliability indices that exclude extreme storms. A recently new term that is being used for electric system infrastructure is **RESILIENCY**.

Resiliency refers to the ability of an electric system to recover quickly from damage to any of its components. Resiliency measures do not prevent damage; rather these measures enable energy systems to continue operating despite damage and/or promote a rapid return to normal operations when damages/outages do occur.

A simple example of resiliency is a design technique referred to as **single contingency design.** Consider an electric power substation equipped with two power transformers. If one of the transformers fail, the lead time on a replacement transformer can be several months. Therefore, the electrical loading on the transformer would be limited to 50% of their capacity. Thus if one transformer fails, the remaining transformer can serve all of the load. The spare capacity does not prevent the damage but rather provides a means for rapid return to normal operation. Many electric distribution systems are designed based on the single contingency design philosophy.

An example of lack of resiliency is the impact of flooding from Super Storm Sandy. Many substations were flooded by the rising waters, and restoration of power could not begin until the water resided and the electric control (relays,

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AUGUST 9
Distribution Planning Criteria

Note: All webinars are recorded and are available for viewing post-presentation.

batteries, and communication apparatus) within the substation were inspected, repaired and/or replaced. One mitigation technique for resiliency is to relocate substations to higher ground or construct dikes around the substations to mitigate flooding. **These are very expensive options and it is important to remember these investments do not prevent outages, they only speed up return to normal operation.**

There are a few common strategies that are utilized to achieve grid resiliency: **System Hardening, Planning and Training, Microgrids, and Smart Grid Technologies**.

SYSTEM HARDENING is a technique used to make the utility's infrastructure less susceptible to storm damage. One of the most common storm hardening methods is placing power lines underground. That method appears to be moving forward in the District of Columbia where PEPCO will be converting roughly 30,000 customers from overhead service to underground service. This is a very expensive undertaking; however, the citizens and local government wished to increase the resiliency without sacrificing the trees. This resulted in with a situation where the cost of the power line undergrounding will be borne by the rate payers.

System hardening techniques are also used by utilities in Florida. One example is to strengthen certain poles on the system. Not all poles are created equal as some poles are more critical to the reliability and resiliency of the system so capital dollars are invested to strengthen these key poles. During a major hurricane about 0.5 to 1.5% of poles will fail. By focusing storm hardening on just 1% of poles, Florida utilities are cost effectively improving resiliency on the system.

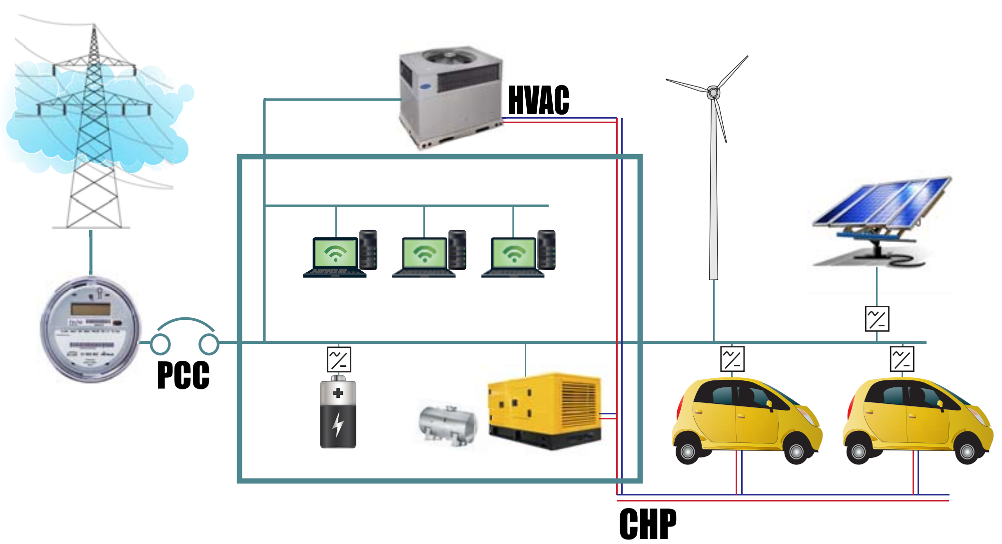
A study in Maryland found that a series of major weather events (i.e. ice storm, wind storm and a hurricane) did not result in major damage to electric power substation or service drops to individual homes, but instead, the critical damage was to the distribution poles and wires.

So Maryland utilities do not focus on hardening substations but focus on certain distribution lines and/or key poles on the system.

PLANNING and TRAINING is an extremely important measure for improving system resiliency. A well trained staff combined with a plan for restoration can greatly improve the efficiency of the restoration. These plans should include emergency operation plans and a command and control structure for major events. The training often includes table top exercises to practice these plans and to identify weakness in the plans. One electric utility in Oregon is preparing for a potential tsunami caused by a fault line west of Washington and Oregon. The predicted tsunami in Oregon could be similar in size to the wave that hit the Fukushima Nuclear Power Plant. Part of the electric utility's planning includes training for the command and control during major events and developing an emergency operation plan.

Another method being explored by some utilities is the use of MICROGRIDS (as seen in **Figure 1**). An advanced microgrid functions as an isolated distribution network with one or more distributed generation sources. Essentially, a microgrid can become an islanded power system that remains running even after a major weather event. One example is a college campus which has combined heat and power (CHP) plant and possibly other generation resources. Combined, these resources can serve all or most of the campus electric load. After Super Storm Sandy, the Princeton University had roughly 13 MW of generation running which served not only the campus loads but also served as staging ground for police, firefighters, paramedics and other emergency-services workers from the area using Princeton and charging station for phones and equipment.

Figure 1. Corporate Building/Campus Microgrid



BG&E has proposed a community microgrid in Baltimore equipped with 2 MW of capacity. The area proposed for the microgrid would allow an island of electric power to an emergency shelter, a grocery store, a pharmacy, and a

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gas station. These basic services would be within 5 miles of more than 200,000 people.

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SMART GRID TECHNOLOGIES can drive improvements in system resiliency and reliability. Many systems are using Advanced Metering Infrastructure (AMI) meters which can provide needed outage information. This includes signals when power goes off and also signals when power is restored. This information can accelerate restoration times. Another smart grid technology is "self healing" systems. Self healing is similar to an automatic transfer scheme which will automatically transfer from a preferred source to an alternate power source. When expanded to an electric distribution grid, it is possible to remotely control numerous switches with more than eight sources and the intelligence to switch to isolate a fault. These systems provide fast restoration of outages. Many different manufacturers are developing and offering systems and many of them have already been proven in field demonstrations.

In the electric industry, the term reliability is slowly changing to include the concept of resiliency. Since major weather events will continue to occur, utilities are expected to be able to recover quickly and efficiently. Major weather events tend to identify all of the weak points on an electric system making restoration that much more difficult. However, by focusing on design, maintenance, and training, utilities can improve their ability to rapidly return their communities to normalcy.

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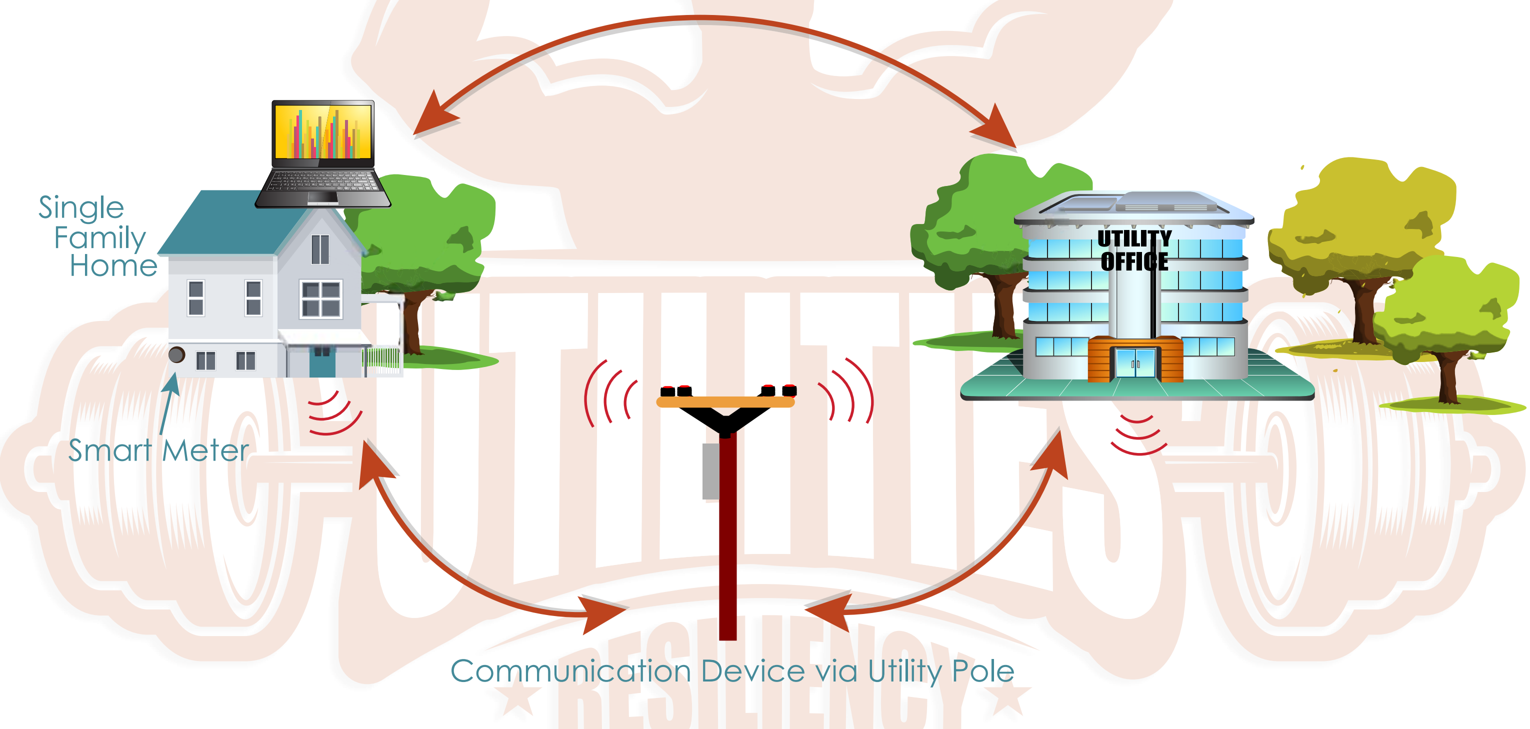
Figure 2. Advanced Metering Infrastructure Systems



The KEY to Maximizing the Value of Your Own Transmission System

Have you ever noticed when automobile advertisers are touting their latest and newest toys, much is made of the monthly lease payments but rarely do you hear about the actual cost of the car were you to buy it outright? At the end of the lease, you had the privilege of driving the vehicle, but you never actually "owned" the car. Transitioning that concept to transmission, many load serving or transmission dependent customers have been paying for transmission facilities owned by incumbent transmission providers for decades through grandfathered agreements and the Open Access Transmission Tariff (OATT) for the privilege of driving across those wires but never owning any assets. **Wouldn't it be nice if there was a way to have someone send you a check for your facilities for a change?** The **key to unlocking this mystery** can be found in how transmission facilities are qualified for inclusion in the region where the electric utility's load is located and how a utility can make modifications to their system to leverage their current transmission assets. **There are five easy steps to follow:**

The first step is to **UPDATE RECORDS.** In order to file an accurate revenue requirement for transmission assets, an electric utility must have accurate knowledge of their existing system. This needs to include knowledge of what is in the field and what is in the accounting records. If those don't match then utilities should make the effort to synch those two areas. When it comes to field data, having detailed records of each element in the field can also help with facility rating determination and other potential NERC requirements.

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Once the records are in order, take time to know the landscape. For electric utilities who are procuring transmission service from a company that has their own OATT, Section 30.9 is the primary vehicle to get credits for qualifying facilities. For electric utilities located within a Regional Transmission Organization, like PJM, MISO or SPP, learn the rules for what is considered "transmission" for tariff purposes. The standard for counting a facility as transmission can take many forms ranging from the FERC Seven-Factor Test to the number and types of customers on a circuit to a particular voltage level cutoff to a "contiguous path" standard. Also, just because a facility qualifies as a Bulk Electric System element under the NERC definition does not mean that it qualifies as a transmission element under the OATT, and visa-versa.

Next in the decision process is to **ASSESS THE BENEFITS AND RISKS.** The main benefit of placing qualifying facilities under the OATT is revenue recovery for existing transmission assets that qualify under the transmission provider rules. The other benefit comes from the return on equity available when assets are placed under the control of a RTO. At present, the ROE in most RTOs is over 10.5% (and some RTOs have ROEs as high as 12.25%), and even if that ROE is reduced, the return is still a plus when compared to most public power/non-profit entities weighted cost of capital. Risks can take two forms: impacts of qualification of existing facilities as a result of grid expansion and modification, and additional NERC compliance exposure. Of course, the cost of becoming a Transmission Owner in a RTO will need to be factored into the decision.

After weighing the options and deciding to move forward, it's time to **LOOK FOR OPPORTUNITIES.** First, look for places on the existing system where normally open points exist and determine if it is feasible to close those points and created looped network facilities. Just because it is technically feasible does not mean that the lines as designed can handle significant loop flow. Power flow analysis can be performed to determine how the electric system will respond under multiple contingency conditions. If no overloads or voltage problems are identified, then it is time to move forward with the facilities qualification process. If problems are revealed then the electric utility may

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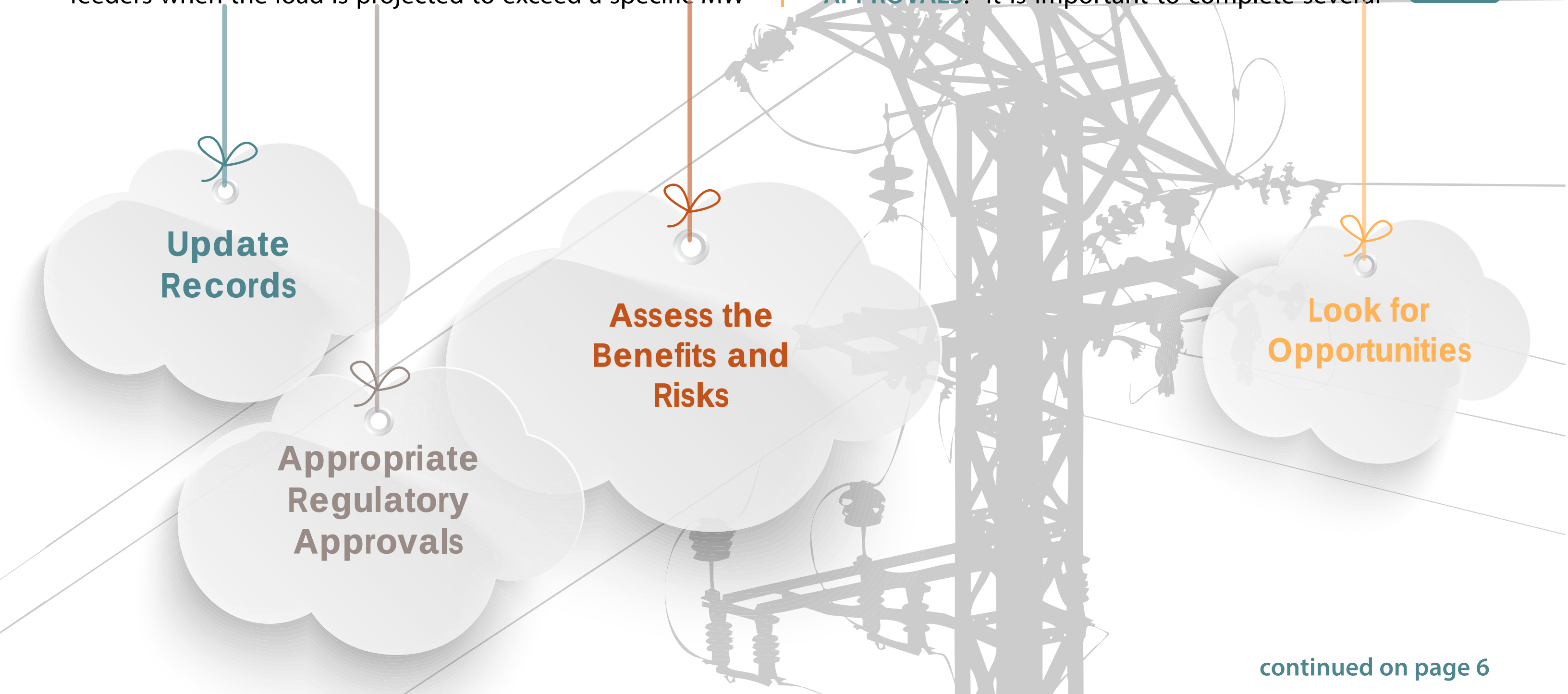
want to determine what needs to change with the existing facilities before closed loop operation occurs. Next, the electric utility should review the reliability problems identified by the regional entities' annual transmission planning process and see if there are opportunities to loop in the electric utility's lines that can resolve local issues. In many instances, the transmission provider or regional transmission organization does not have the granularity of non-looped or lower voltage facilities in their power flow models, so they do not look at lower voltage solutions to mitigate known problems. Conducting an independent power flow analysis with the electric utility's local facilities included may reveal solutions that others do not or cannot identify.

Another tool in the box is the use of **LOCAL PLANNING CRITERIA** to reflect the unique nature of your electric system. In many cases, the needs that drive transmission expansion are more than the typical NERC Transmission Planning or TPL criteria. Sometimes, grandfathered power supply and transmission agreements include language related to maintaining a particular voltage or power factor at the point of delivery. In order to maintain adequate voltage downstream from the POD, additional facilities or equipment may be needed. The inclusion of minimum nominal voltage or maximum voltage drop criteria at the end of radial transmission circuits can be used to encourage the development of radial-to-looped conversion to meet such a criteria. Many utilities employ a load-at-risk criteria to address potential reliability concerns. Load-at-risk can take several forms. For example, some companies look at secondary feeds or looped service to feeders when the load is projected to exceed a specific MW threshold regardless of the length of the circuit where the load is located. Another option is the use of a MW-mile criteria, to be able to capture those lines where circuit length may expose low load but high priority service.

The decision to step out and join the ranks of the network transmission facility owners does have some risks that need to be addressed, including operational control questions, NERC compliance responsibilities, and joint planning requirements. If an electric utility decides to move forward and place their qualifying facilities under a RTO tariff then that means increased communication requirements with the RTO. Outage coordination now becomes a coordinated effort through the RTO. The RTO Reliability Coordinator now has greater visibility into the individual electric utility's system and has the authority to direct those utilities to take action at their directive, in accordance with NERC requirements. Speaking of NERC requirements, there are certain requirements that come with the privilege of being counted as a Transmission Owner (TO) in the NERC Functional Registration. It is important to develop in-house expertise or hire compliance experts who can assist the electric utility with unraveling the mystery of NERC Compliance as a TO. The planning of transmission facilities now involves greater coordination due to loop flow impacts across the electric utility's lines, modeling requirements to make sure that all of the electric utility's qualifying facilities are included, and assessing the impact of proposed solutions by others on the individual electric utility's system.

Finally, get the **APPROPRIATE REGULATORY APPROVALS**. It is important to complete several



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activities, including understanding the requirements for facilities qualification for either 30.9 credits or revenue sharing agreements, filing of transmission revenue requirements with FERC, and the negotiation of revenue sharing agreements with existing Transmission Owners who share a common pricing zone.

Just like the lease versus buy decision for modes of transportation, there are benefits and costs to both and it is important to carefully weigh those factors so that the electric utility can make a decision in which they are both confident and comfortable. Having a coordinated approach between the transmission planning, accounting, compliance and regulatory functions of the electric utility to properly assess those factors can provide long-term reliability and economic benefits for consumers for years to come. ■

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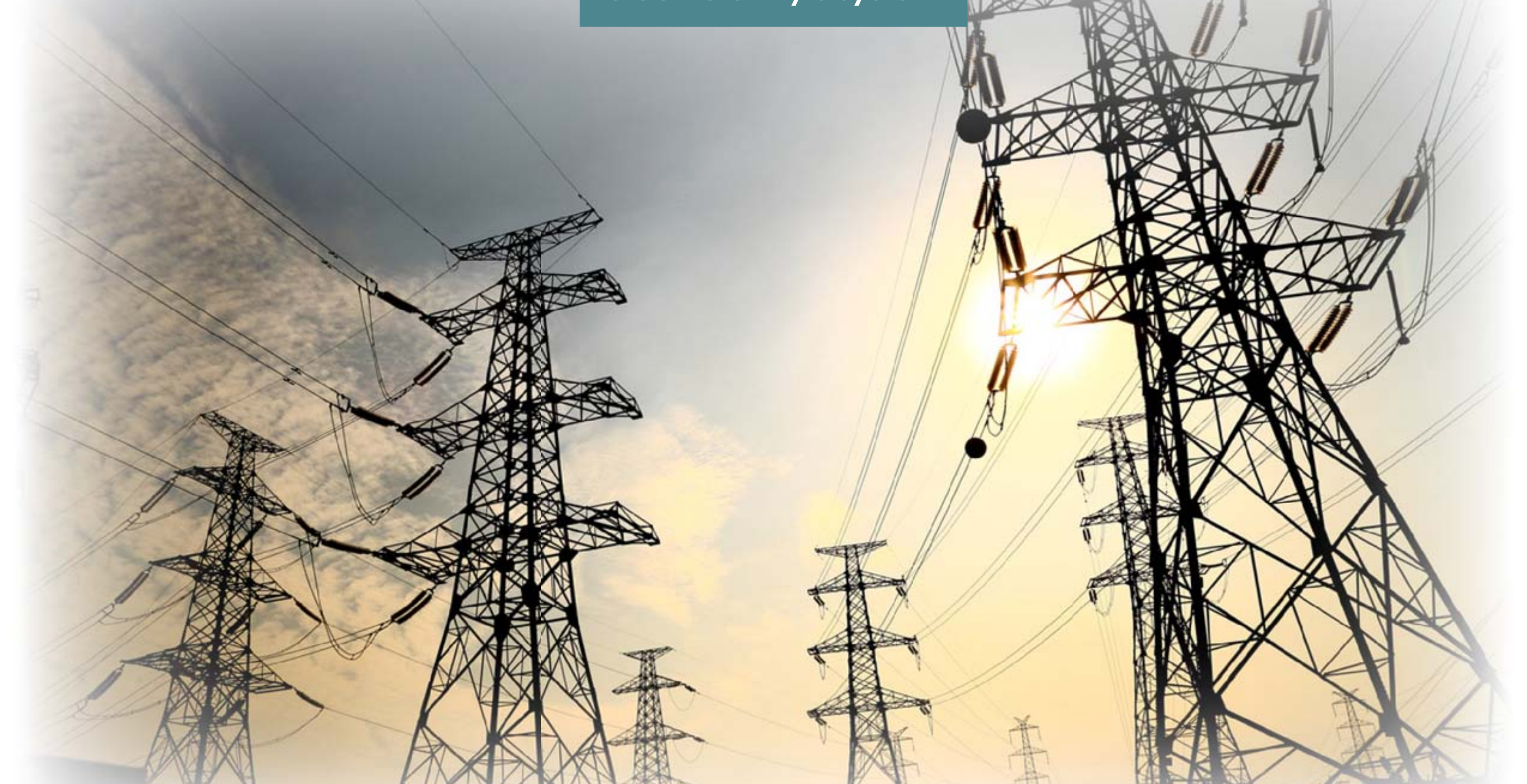

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