TRANSACTIONS

Volume 413
November 2013

A Publication of GDS Associates, Inc.

In This Issue

Smart Grid…The Saga Continues: Using AMI Data for System Planning and Troubleshooting
Pages 1-3
Braxton Underwood, P.E. – Project Manager
Hi-Line Engineering, a GDS Company - Marietta, GA

Advanced Metering Infrastructure meters can provide a plethora of useful planning data to the utility. In addition to providing faster and more frequent meter reads, they can also provide accurate voltage reads, phasing information, and act as a gateway for communication with appliances and energy management systems in homes and business. This article focuses on how AMI meters can be used for system planning and also how they fit in the Smart Grid puzzle.

Capacity Markets: The Debate Continues
Pages 4-5
Elizabeth Kaiser, P.E. and Ernesto Perez, P.E. Project Managers, GDS - Marietta, GA

Capacity Markets have been introduced in many RTOs throughout the country with the basic purpose of ensuring enough electric supply is available to meet the demand of consumers. The concept sounds simple enough, but there is surprisingly a lot of strong debate on both sides of the Capacity Market argument.

TransActions to Transition to Digital Format
GDS will start the process of transitioning the TransActions newsletter to an e-newsletter. Our first step is making sure we have your correct information. Take a minute and help us update our files...**see the back page for more info.**

TRANSACTIONS is a service of **GDS Associates, Inc.**, a multi-service consulting and engineering firm formed in 1986.

For more information about **GDS**, our services, staff, and capabilities, please visit our website @ **www.gdsassociates.com** or call us @ **770-425-8100**

IDEAS WANTED!

We want to hear your ideas, feedback, and suggestions for this newsletter.

Email us at:
transactions@gdsassociates.com

Smart Grid…The Saga Continues: Using AMI Data for System Planning and Troubleshooting

We are continuing our **Smart Grid Series** with a focus on using **AMI Metering Data for System Planning and Troubleshooting**.

Let's begin our discussion with a little history on automated metering. The first generation **Automated Meter Reading (AMR)** systems arrived on the scene in the mid to late 1990's. The first generation AMR metering systems had one primary focus, which was to automatically send back a meter read. These early systems utilized one-way communication via Power Line Carrier (PLC) method of communication. This method of communication was very slow and only yielded roughly one meter read per day. While meter reading was the sole focus, some of the other initial benefits that were useful to utilities included reducing manual meter reading expenses, enhanced kWh and kW loading data for system models, some voltage level indication, and a way to potentially discover theft or diversion. Some of the early AMR systems also had the capability to identify phasing. Several years later, some manufacturers introduced two-way communication capability to their AMR systems. This allowed for communication with the meter and other enhancements such as remote connect/disconnect and the ability to ping the meter for a read. As the technology developed, so did the communication protocols. Many of the newer metering systems utilize wireless technology to transmit faster reads and accept communication commands from a central computer.

Fast forward several years and the latest development in meter technology is **Advanced Metering Infrastructure (AMI)**. AMI meters have the same primary goal of obtaining meter reads, but they are more advanced than their AMR brethren. The latest AMI meters are capable of continuously sending 15 minute meter read intervals or reads on demand with a meter ping. These new AMI meters also provide a plethora of useful planning data to the utility. In addition to faster and more frequent meter reads, they also can provide accurate real time voltage reads and phasing information. Many utilities are also using the AMI meters as a gateway for communicating with appliances and energy management systems in homes and business. A detailed list of these available features for AMI meters are shown below:

- **Faster meter reads** (available by pinging the meter on demand or on a schedule)
- **Faster outage detection**
- **Ability to ping the meter to get instant status updates** (this can reduce the number of call outs (truck rolls) for a complaint that is on the member side of the meter)
- **Latest "smart meter" technology allows for distribution automation, conservation voltage reduction at peak, and volt/var management**
- **Allows for better integration with load management practices and demand response**
- **Ability to wirelessly communicate with appliances and energy management systems**
- **Upgraded remote connect/disconnect features**
- **Better interval (15 minute) metering data collection** (aids in system analysis for system modeling, cost of service, transformer management, and resolving high bill complaints)
- **Easier migration to a Meter Data Management System (MDM)**

continued from Page 1

- **Access to power quality information**
- **Defined communication and security standards**
- **Real-time monitoring possible**
- **Better integration with multiple software packages including CIS, OMS, MDM, engineering analysis software, and GIS**
- **Ability to better adapt to future Federal or State imposed reliability, conservation, or security standards**
- **Savings that can be realized through engineering analysis due to the availability of more data to optimize the distribution system**
- **Satisfies current desire for real time billing information**
- **Better adaptation to net metering installations** (distributed generation)

AMI is the logical and important first step for a utility in implementing a modern smart grid. Once a utility has an AMI metering system in place, the utility is in a position to leverage the data provided by the AMI system to improve service to its consumers. The availability of real time data provides system engineers and operations personnel the ability to examine their system with a level of certainty like never before. The main AMI benefits discussed in the remainder of this article are in relation to distribution system planning and troubleshooting.

AMI is the logical and important first step for a utility in implementing a modern smart grid.

Enhanced system planning and optimization using detailed system model: The enhanced information available from AMI meters is very useful in ensuring proper load allocation in the detailed engineering model. A detailed engineering model is one of the most powerful tools in the system engineer's arsenal. However, the engineering model is only as good as it's data input. One of the major cornerstones of the engineering model is the geographic representation and accurate definitions of the distribution lines, devices, transformers, and customers. Another cornerstone is the loading data that is used to allocate the model to future or past peak loading for planning analysis. The data provided by AMI metering can be used to ensure customers are in the right location in the model and tied to the correct phase. The enhanced data also allows for an accurate representation of each consumer's past peak demand and usage data. This data ensures that load is distributed correctly within the model for a more accurate representation of actual loading. Once this information is correctly applied, the system model can be used to identify conductor ampacity, transformer overload, or voltage concerns as well as the impacts of upgrades to the distribution system infrastructure. Voltage readings from the meters can also be used to verify the accuracy of the model results. A detailed engineering model can also be combined with an Outage Management System (OMS) for enhanced functionality. These data sources can also be used to deploy Intelligent Electronic Devices (IEDs) in critical locations on distribution feeders. These IED devices can include reclosers, automated switches, voltage regulator controls, and capacitor controls. These IEDs can be monitored and have the ability to send real time data back for decision making by a central computer or engineer in order to best respond to system fluctuations and outages. This data can be used in conjunction with the AMI metering data to fine tune the distribution system. Therefore, AMI provides critical data that can be used to determine the proper approach to voltage and var management and how to respond to outages.

Past experience has shown that the majority of distribution transformers are oversized. There can be significant cost savings available to the utility if they can size transformers more effectively and increase the number of consumers per transformer.

Use enhanced metering data to perform transformer loading and troubleshooting analysis: Enhanced metering data can also be used to perform transformer loading analysis. The AMI data provides coincident peak loading for consumers served by a single transformer. This provides a more accurate assessment of transformer loading when compared to traditional methods. In the past, utilities have sized transformers for new consumers using rule of thumb methods or simple calculations of what the customer usage and demand will be. Commercial and industrial transformers are typically sized using a combination of the proposed customer panel loading schedules and the planning engineer's experience. Each of these methods must factor in the diversity of loads. However, system peaks usually do occur at certain times during the day including the morning before work and school, the evening around dinner time, and heat of the day when cooling load is the biggest driving factor. Past experience has shown that the majority of distribution transformers are oversized. There can be significant cost savings available to the utility if they can size transformers more effectively and increase the number of consumers per transformer. The data provided by AMI metering systems can help utilities make better decisions on transformer sizing. Another useful feature that is available is using the AMI data to see if transformers are overloaded or failing. This use of the data can help avoid unexpected outages and the resulting downtime for utility customers.

Use metering data to develop time of use rates for billing: AMI metering provides the means to analyze copious amounts of customer usage data over the period of an entire day, week, month, and year. This data can be useful to utilities to develop Time of Use (TOU) rates. TOU rates can be a tool for utilities to offer incentives to progressive consumers that have the capability to shift their usage to off peak periods. These types of rates have several benefits for utilities and consumers. The consumer is provided with the ability to reduce his bill, while utilities save on demand charges at peak and power cost adjustments. These shifts in usage patterns also aid in reducing system losses at peak. Reducing system losses is a major focus for utilities in the current period of increasing power supply costs. Look out for future Transactions articles about TOU and other dynamic pricing programs enabled through AMI metering.

Use metering data for reliability analysis: Surveys have shown that consumers would be willing to pay around $3.00 to avoid a 30 minute outage. Interestingly, the same surveys indicated that they would be willing to pay roughly the same $3.00 to avoid an instantaneous blink of their lights. Utilities will have to respond to and balance the consumer's desire for infrequent outages and blinks to their systems. AMI meters today have the ability to report back momentary outages. These momentary outages are typically associated with overcurrent protection schemes that are designed to keep temporary faults temporary and not become a sustained outage. These may include incidental vegetation contacts, animal induced outages, and lightning. This AMI data can be analyzed to help identify which consumers are experiencing a high number of momentary outages. Analysis of customer blinks provides useful data for determining adjustments to existing overcurrent protection schemes or locations where a recloser might be needed versus a simple fuse. Utilities have a sharper focus on reliability today and take customer satisfaction very seriously. AMI data provides an additional tool for the utility to use to help evaluate and maintain reliability goals.

Surveys have shown that consumers would be willing to pay around $3.00 to avoid a 30 minute outage. Interestingly, the same surveys indicated that they would be willing to pay roughly the same $3.00 to avoid an instantaneous blink of their lights.

Use metering data for troubleshooting failing equipment: Most utilities are using AMI metering data in conjunction with Outage Management Systems (OMS) to troubleshoot and identify failing electrical equipment. A routine analysis of AMI data can indicate momentary outages or loss of voltage at meter location on a distribution system. The OMS system can then be used to graphically display the location of the suspect meter or group of meters. This approach has been used successfully to identify failing equipment. Specifically, this can identify a failing transformer or voltage regulator if voltage fluctuations are significant and fall outside the ANSI Range A levels. Many system problems can be identified early on, before a catastrophic failure occurs, which could result in a lengthy outage.

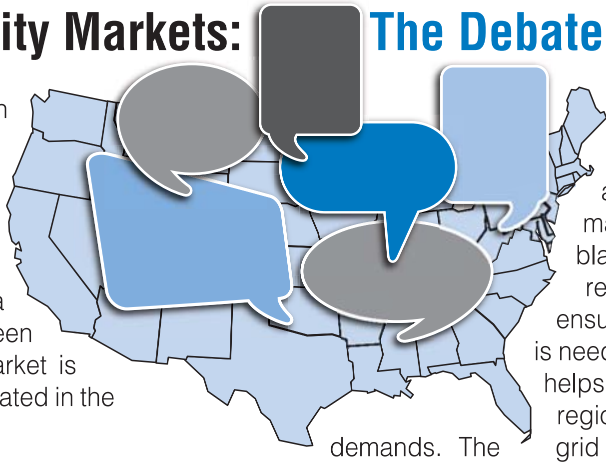
Conservation Voltage Reduction (CVR) at Peak: In previous articles, we discussed CVR and its benefits. AMI metering data can be used to implement CVR. The newer style AMI metering systems are capable of reporting real time voltage information at each metering location. This data can be used to reduce the substation or individual feeder bus voltage while maintaining the required ANSI range A voltage levels at each meter location. This reduction in voltage at peak can yield significant demand savings at peak. Some CVR trials have shown that a 1-2% reduction in peak kW demand is possible, depending on the load mix on the feeder.

Reducing service call outs: A consumer calls in an outage complaint on a blue sky day. Without AMI metering, there is no way to verify whether voltage is present at the meter or if the problem is in the consumer's home. This results in a truck roll to investigate the cause of the outage. Once there, the serviceman finds that the cause was on the member's side of the meter. AMI can be used to reduce these false call outs due to the system's capability to ping the meter. If the meter ping shows voltage at the meter, the member can be instructed as such and asked to investigate a problem on the member's side of the meter (i.e. tripped breaker in panel). This is especially useful as an electric utility is recovering from a minor or major storm. Consumer call backs are eliminated which reduces labor time and more quickly identifies lingering individual outages.

As I've just described, AMI can be used in various ways to improve distribution system planning and reliability. However, there are many different AMI systems available with differing communication protocols and features, so utilities should perform proper due diligence before selecting an AMI system. This typically includes doing an AMI business case and vendor analysis prior to selecting an AMI system. Some utilities may also look at AMI metering options as part of a Technology Work Plan and consider how AMI will fit in with existing systems in place as well as future technology purchases. ■

For more information or to comment on this article, contact Braxton Underwood, P.E. at Hi-Line Engineering - a GDS Company, 770.799.2369 or email: braxton.underwood@gdsassociates.com

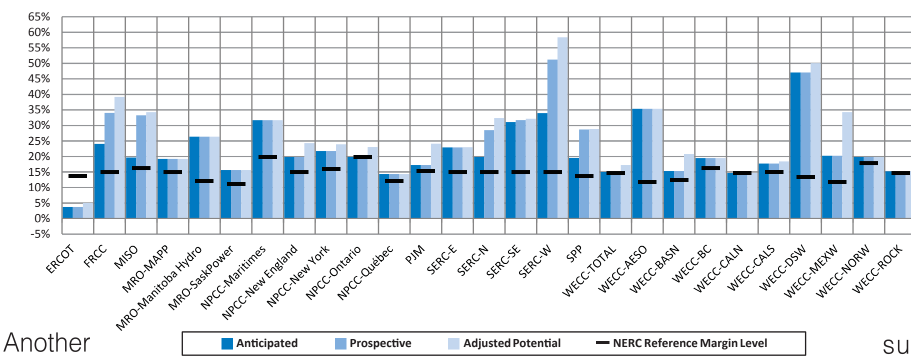
Capacity Markets: The Debate Continues



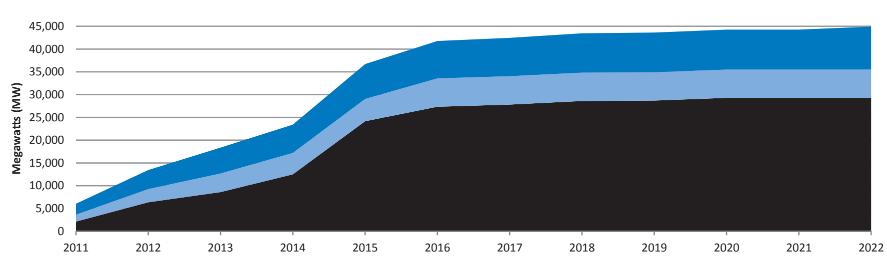
Capacity markets have been introduced in most U.S. RTO/ISO footprints with the basic purpose of "keeping the lights on" and ensuring enough supply will be available to meet demand. It sounds simple, but surprisingly, there is quite a bit of debate on whether or not capacity markets are a good idea. This issue has recently been brought to the forefront as a capacity market is currently being considered and heavily debated in the ERCOT Market of Texas.

The capacity markets in the various U.S. RTOs vary widely in sophistication. PJM's market (termed the Reliability Pricing Model or "RPM") was established in 2007 and may be the most sophisticated. Auctions are held three years in advance of the planning year where generators can offer capacity to meet forecasted load, and the auction clearing price sets the price loads pay to the generators. Load requirements are forecasted based on average contribution to the 5 highest summer peaks of the PJM system (referred to as the "5-CP") plus a planning reserve margin. The market in the NYISO is also a forward market and operates similarly, but with less complexity, than PJM's market. Up until recently, MISO's capacity market has been purely voluntary, but is currently evolving into a non-voluntary market more like PJM's. Another variation of capacity markets is a load planning requirement, such as the California Public Utility Commission's requirement for all providers of retail energy to either own or contract for enough capacity to meet peak load plus a planning reserve margin. On the other side of the fence are regions like ERCOT and SPP where no capacity markets have yet been formed, but ERCOT is seemingly moving towards establishing a capacity market.

2017 NERC-Wide Peak Season Planning Reserve Margins*



NERC-Wide Confirmed Retirements by Fuel Type (Summer Capacity)*



Capacity Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	2,131	6,380	8,597	12,496	23,615	26,719	27,198	27,971	28,067	28,650	28,650	28,650
Petroleum	1,531	2,880	4,088	4,719	4,909	6,221	6,221	6,221	6,221	6,221	6,221	6,221
Gas	2,405	4,195	5,565	6,086	7,530	7,919	8,121	8,365	8,417	8,493	8,493	8,611
Total	**6,067**	**13,454**	**18,250**	**23,301**	**36,054**	**40,858**	**41,539**	**42,556**	**42,705**	**43,364**	**43,364**	**43,482**

The top chart above shows various projected Planning Reserve Margins by 2017 versus the NERC Reference Margin Level. Most regions are projected to remain sufficiently above the NERC level by 2017, but NERC forecasts that by 2022 many areas will dip below these target levels. This concern over whether or not adequate capacity will be available in the future helps to fuel the capacity market debate.

Proponents' Perspective

Reliability is a major concern across all electric markets. Current electricity markets do not prevent the possibility of blackouts. In order to meet demand in a reliably consistent manner, regions must ensure that supply will be available when it is needed most. The use of capacity markets helps establish the support base by which regions are able to meet their system-wide demands. The grid operator for any region must match production with demand instantaneously. If markets were designed from an energy-only perspective then consumers would experience constant boom and bust cycles that would negatively impact the long-term planning goals that are fundamental to power plants with life cycles of 20 plus years. For example, peaking power plants, with their low utilization (i.e. low capacity factors) but low fixed cost requirements, provide peaking energy and reserve capacity to the market. In an unregulated system, these plants survive on high market prices in a relatively few hours to recover costs and earn a return on investment. If peak prices are capped, as is done in most markets, these resources may not be funded adequately. A capacity market, therefore, is designed to reduce investment risk, to enable greater competition among suppliers, and to enable rational tradeoffs between resource adequacy and investment costs.

The topic of reliability is especially important given the current outlook of plant retirements. A total of 24 GW of operating capacity are expected to be retired from 2013 to 2018. The majority of the confirmed retirements, 19 GW, will be from traditional coal generating resources. The importance from a reliability perspective is: **How will the void caused by the retirement of these coal plants be filled to insure cost efficient and consistent power?**

Proponents argue that proper **price signals** are one of the key strengths of the capacity markets. The belief is that the best way to promote smart investments in different kinds of assets throughout the generation grid is to send generators efficient price signals. A capacity market does so by compensating generators

*Source: NERC 2012 Long-Term Reliability Assessment, Nov 2012

continued from Page 4

with revenues for capacity that a power plant can generate and/or the capacity of power that can be reduced during demand response periods. This reimbursement for operational capacity outside of the energy markets has refueled and developed additional capacity solution efforts including renewables and **demand response programs**.

Participation in demand response programs has been proven to work in PJM as it has helped in bidding capacity prices down. Consumers have an incentive to participate in these programs because they are able to monetize their ability to reduce demand during critical peaks thus increasing the reliability of the overall electric system and helping to avoid system emergencies. An increasing number of consumers can alter their normal consumption patterns by lowering their demand in response to hourly market prices.

What the Critics are Saying

On the other hand, many are critical of the capacity markets and do not believe they are as efficient and reliable as some may claim. They argue that no other economic market other than electricity utilizes a capacity market. These other markets continue along efficiently, so why should electric markets be any different? For example, when you buy ice-cream from an ice-cream store, you do not pay an extra cost just to ensure enough ice-cream machines are available to cover the busiest times. If ice-cream sales begin to increase, the store will eventually invest in additional machines, or open another store. Critics argue that the energy markets alone provide enough incentive for new capacity because if energy usage starts to increase, new capacity will be built. Having a separate capacity market is therefore unnecessary and **inefficient**. Capacity costs are ultimately recovered from consumers through **higher electric bills** with the majority of these additional revenues going to existing generators.

Another criticism of capacity markets is that when capacity prices are low, it is **not necessarily beneficial to the generators** who are receiving these revenues. The revenues may not be high enough to cover the costs of maintaining generating units and thus do not provide enough incentive to build new generators or to continue maintaining existing ones. In addition, the short-term price signal of capacity markets does not provide long-term pricing support necessary for long-term investment generation decisions. This obviously poses questions regarding reliability and concerns that there will not be enough generation to meet new demands in the future which is the very issue the markets were designed to solve.

This issue was further brought to light in May 2013 when the PJM capacity auction cleared at a much lower level than many analysts had predicted and more than 50% below the previous year's clearing price. A major source for this price drop was an increase in import capacity from regions outside of PJM. Imports increased close to 90% above the previous year's imports causing a large increase in offered supply while demand forecasts remained relatively flat. About half of the new imports came from MISO with generators hoping to receive more value in PJM with its historically higher capacity prices. This also brings into question concerns about reliability since only about 60% of those imports had firm transmission service into PJM. Can these imports really be relied on to meet peak demand? Some argue that these generators are taking advantage of PJM's current lack of limits on imports and are thus abusing the system rather than helping to provide reliable generation.

Critics also **question the reliability** of renewable resources, Demand Response and Energy Efficiency Programs which are often utilized as capacity resources. Some are uncertain that these types of resources can really be very reliable in peak demand situations for a long period of time. Another argument made by critics is that it can be a very expensive and time-consuming process to install a new capacity market in a region, and thus can end up **tying up a lot of valuable resources** (both human and capital) along the way.

In summary, capacity markets can be found throughout many parts of the country. Concern over adequate capacity reserve margins is again fueling the capacity market debate. Planning reserve margins across the various electric markets are expected to remain sufficient through 2017; however, NERC forecasts by 2022 many areas will dip below their capacity targets. The retirement of an estimated 19 GW of coal-fired generation is expected by 2018. Proponents argue capacity markets offer a way to efficiently send price signals to generators in order to maintain system reliability and encourage alternative capacity solutions. Peaking generators in particular, who are used and reimbursed in peak market conditions, would not receive enough revenues from the energy-only market. The capacity market provides a solution to recover costs and provide for a reasonable return on investment.

Critics on the other hand argue lower revenues when capacity prices are low hurt generators. No other markets function in a similar manner to capacity markets therefore they are unnecessary, inefficient, and ultimately lead to higher electric bills since the costs are passed on to the consumers. Recent imports from MISO to PJM support this notion and highlight the market abuse that can occur without adequate oversight. Furthermore, critics question the reliability of alternative capacity program solutions such as renewable resources, demand response, and energy efficiency measures. Introducing a comprehensive capacity market can also be an expensive and time-consuming process.

For help navigating the capacity market debate, Day 2 market requirements, and other market-related aspects in general please contact Elizabeth Kaiser and Ernesto Perez. ■

For more information or to comment on this article, contact:

Elizabeth Kaiser, P.E.
770.799.2368
elizabeth.kaiser@gdsassociates.com

Ernest Perez, Jr., P.E.
770.799.2405
ernesto.perez@gdsassociates.com

GDS Associates, Inc.

Corporate Headquarters:
1850 Parkway Place
Suite 800
Marietta, GA 30067
770-425-8100
Fax: 866-611-3791
www.gdsassociates.com

Texas:
919 Congress Avenue
Suite 800
Austin, TX 78701
512-494-0369
Fax: 866-611-3791

New Hampshire:
1155 Elm Street
Suite 702
Manchester, NH 03101
603-656-0336
Fax: 866-611-3791

Wisconsin:
440 Science Drive
Suite 400
Madison, WI 53711
608-273-0182
Fax: 866-611-3791

Florida:
111 North Orange Avenue
Suite 750
Orlando, FL 32801
407-563-4035
Fax: 866-611-3791

Hi-Line Engineering
a GDS Company

Georgia:
1850 Parkway Place
Suite 800
Marietta, GA 30067
770-426-0819
Fax: 866-611-3791
www.hi-line-engineering.com

Alabama:
1826 Opelika Road
Auburn, AL 36830
334-887-3297
Fax: 866-611-3791
www.hi-line-engineering.com

We welcome your comments and suggestions about our newsletter. Please forward any comments to:
transactions@gdsassociates.com

GDS Associates, Inc.
Engineers and Consultants

Mission Statement:

To help our clients succeed by anticipating and understanding their needs, and by efficiently delivering quality services with confidence and integrity.

GDS Associates, Inc. is a multi-service consulting and engineering firm formed in 1986 and now employs a staff of over150 in five locations across the U.S. Our broad range of expertise focuses on clients associated with, or affected by, electric, gas, and water utilities. In addition, we offer information technology, market research, and statistical services to a diverse client base. The size and depth of our firm permits us to offer clients multiple sources of assistance, ensuring complete, competent, and timely service.

TransActions to Transition to Digital Format

During 2013, GDS will start the process of transitioning the **TransActions** newsletter to an **e-newsletter** format. The digital publication of **TransActions** will be emailed directly to our list of contacts who receive the newsletter currently via regular mail. Our first, and most important, step in facilitating this process is to make sure we have your correct email address in our system. Please take a quick moment and go to our website, **www.gdsassociates.com**, and enter your **ID number** *(which is printed above your name on the address portion of this newsletter)*, your **e-mail address** and your **last name** *(see mock-up below)*. This will insure you continue to receive future issues of **TransActions** in the new format. We don't want to miss any of our readers, so please take a minute and make sure we have your correct information.

GDS does not share, sell or trade email addresses. We are committed to keeping email addresses **confidential**.

ID # and **last name**

1234
Mr. Thomas C. Smith
President
Utility Electric Cooperative, Inc.
123 Power Way
Atlanta, GA 12345

PreSorted Standard
U.S. Postage
PAID
Kennesaw, GA
Permit No. 555

RETURN SERVICE REQUESTED

1850 Parkway Place
Suite 800
Marietta, GA 30067