EnergyPulse™ Special Issue

21st CENTURY T&D

Spring 2004

Building a 21st Century Grid

In this issue...

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21st Century T&D

an EnergyPulse™ Special Issue

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Welcome to the 21st Century Grid!

Energy Central welcomes you to this special issue on electric transmission and distribution topics: *Building a 21st Century Grid*.

Even before the events of August 14, 2003, left some 50 million North Americans without power, in some cases for several days, energy industry experts had been warning of a widening gap between the demand for electricity and the ability of our existing infrastructure to deliver it on a reliable, secure basis.

The numbers are hard to refute. Since a peak in the mid-1970s, utility investment for new transmission facilities has decreased by $100 million or more each year, even as electrical demand continues to grow to all-time highs in most regions of the country.

We can all recount reasons why annual transmission spending has fallen to less than half of what it was in 1975: Utility reticence to build without a firm promise from regulators of cost recovery, the difficulties of winning local support for any kind of new power line or generation project, the uncertainties of the restructured power marketplace, and a lack of enforceable standards for reliable service. All have conspired to leave us with a gross mismatch between the ways we produce, trade and use energy in an increasingly digitized society and the delivery system that was built to serve the needs of an industrial economy of the past century.

Since August 14, the debate has turned from identifying the reasons for such a lack of capital spending to attempts to spur new construction, whether through the establishment of new reliability standards or with added inducements for construction investment.

For this issue, we asked noted energy industry leaders to provide us with their thoughts and recommendations for dealing with the investment impasse. This, of course, won't be the final word on how we can create a new system for the coming century. In fact, Energy Central intends this to be the first of a series of similar topics on T&D matters that will join the monthly parade of new electronic magazines devoted to specific topics of interest to professionals in the power and fuels business.

For an overview of the topic we offer a conversation with **Clark Gellings**, vice president, power delivery and markets for the Electric Power Research Institute, which serves as the research and development arm of the U.S. utility and power business. Gellings, who has been tracking the future of power technologies for over 20 years at EPRI, gives us an advance look at a new study into calculating how much investment it will take to bolster and improve our electrical delivery networks. While EPRI's preliminary conclusions point to a need for massive investment, on the order of $100 billion to $200 billion over the next two decades, Gellings puts that into the perspective of a potential $700 billion gain in productivity and service reliability that matches the needs of our electronic world.

The Gellings interview sets a stage for an extended inquiry into whether such investment is likely, and how regulators, lawmakers and transmission system owners can make it happen. **Leonard Hyman**, the esteemed energy industry observer, argues that the business structure and policy framework for transmission services has erected barriers to rational capital investment, although he sees more of an impetus for putting money into local distribution.

The debate over whether financial and regulatory incentives or mandatory reliability standards are the best way to bring about needed changes is taken up by **Bob Gee**, the former chairman of the Texas Public Utility Commission, and **Richard Barker**, president and CEO of Quad Resources. Gee dissects the kinds of incentives being discussed and how effective they might be, while Barker puts his stock in industry self-regulatory efforts, even though pending federal legislation appears to be moving towards mandatory enforcement rules under the auspices of the Federal Energy Regulatory Commission.

Elliot Roseman of ICF Consulting proposes a new measure of the value of reliable electric services that he believes should be incorporated into utility resource planning to help better understand the balance between costs and benefits of funding new transmission infrastructure.

Our *Building a 21st Century Grid* issue also delves into practical considerations of T&D operations, with a review of the use of supervisory control and data acquisition (SCADA) systems by power and fuel utilities, based on the highly regarded annual surveys conducted by **Chuck Newton** of Newton-Evans Research. Newton, who has been tracking SCADA trends since 1983, offers insights as to future directions for matching monitoring and control technologies to the needs of an increasingly complex system, and he discusses the importance of cyber security for SCADA operators.

One of the lessons of August 14th is that we live in an interconnected world, a fact proved by the domino impacts of a tree-line contact incident in Ohio on power users from Michigan to Ontario to Long Island. **Dariush Shirmohammadi** and **David Kopperdahl** of Material Integrity Solutions, Inc., along with colleagues from utilities and research organizations, provide us with a first look at a new device for eliminating power line sags that too often lead to system faults and outages.

Also, attorney **Cynthia Currin** offers a practical to-do list if someone in your company (or a customer in your territory) experiences a serious electrical contact accident.

Bringing the focus back to system investment, our last piece explores the question of whether an anticipated increase in transmission and distribution spending to improve reliability of service will provide significant investment opportunities, not for utilities or merchant developers, but for individuals and institutions. In the highly fragmented electrical products industry, still reeling from years of depressed sales, the answer is not as obvious as it might seem.

By all means, get involved in the debate being hosted here. Our contributors welcome your thoughts and responses to their ideas and recommendations. Energy Central will also consider your proposals for thoughtful and timely articles for future special issues in our continuing series.

— *Arthur J. O'Donnell, Independent Energy Journalist, The Energy Overseer, San Francisco energyoverseer@comcast.net*

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PennWell MAPSearch || *Updated to reflect recent changes in the power industry, this map is color-coded for easy identification. The map shows major transmission lines 230kV and greater; identifies utility power plants 200MW and greater; lists plant owners, operators, MW, and fuel type; Investor-Owned Utility service areas of more than 10,000 consumers; contains the North American Reliability Council (NERC) regions. Size: 40" x 72", Scale 1" = 55.2 miles, January 2003*

Managing Aging Distribution System Assets

EPRI || *This report describes methods for analysis of failure and repair of equipment, equipment aging, and economic considerations. It presents results of a literature search on what is currently known with respect to managing aging assets, reviews and critiques several methods of analysis that have been applied to the problem of aging assets; describes a real utility problem (aging air breakers), and a simple solution. Information in the report will support the development of an optimal (least-cost) policy for maintenance and replacement of electric distribution assets.*

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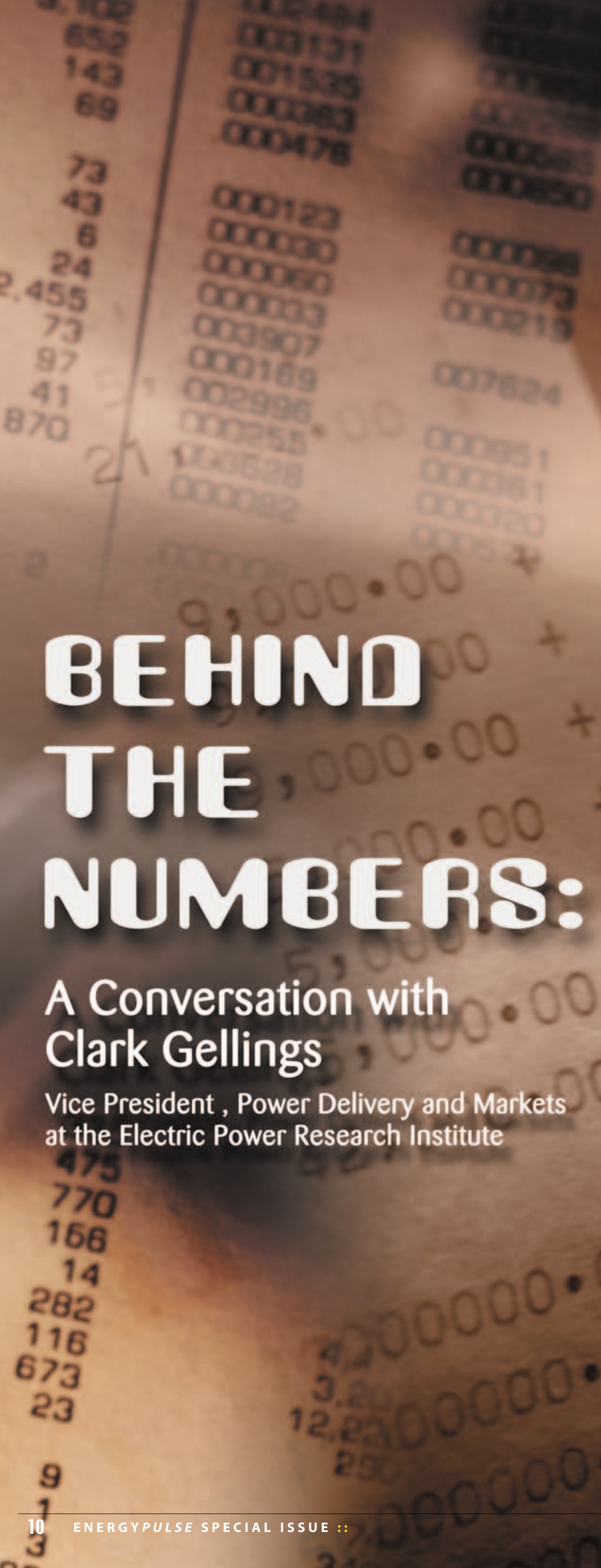

BEHIND THE NUMBERS:

A Conversation with Clark Gellings

Vice President , Power Delivery and Markets at the Electric Power Research Institute

EC: *Clark, you've been something of the visionary for EPRI. A couple of years ago you helped head up the Technology Roadmap project. Please step back a couple years and tell us how far along the roadmap we are and if things are as dire as they seem.*

CG: I think we are in trouble. I think we have a power delivery system obviously designed for one purpose and being used for entirely another. The technologies are 40 to 50 years old and haven't been modernized.

Every other industry in the modern world has been computerized, has been laced with sensors and computational ability and communications and here we have this dumb electric system that's essentially mechanical, controlled mechanically with limited information coming to us about its performance or its condition.

EC: *Why are we in this situation?*

CG: Well, why, that's a complex set of issues, none the least of which are restructuring and are perhaps not paying attention to the question of who pays and who gains from infrastructure. We could point to water, bridges. It's the same general issue. We've got an infrastructure that is literally a national treasure, a $360 billion investment out there that at this point we are neglecting. We are at the lowest point of construction expenditures, inflation adjusted, since the Great Depression.

I guess you could say it is potentially a disaster waiting to happen.

EC: *But isn't it true that this dearth of investment in infrastructure has been going on long before restructuring? Investment in transmission has been on a downward slope since the mid-1970s.*

CG: That's true. Restructuring didn't help us solve the problem as to who's going to make investments and who's going to gain from them. Of course, laced with this is the question of "Don't build anything near anyone, I don't want that transmission line in my backyard." There's failure to recognize the importance of advanced technology and how that could actually help enhance the functionality of the system.

In my vision I don't talk just about "We need to build more." Yeah, we do. But that isn't the only answer.

I can squeeze more out of the existing system with advanced technologies. I could modernize the system and literally my view is that the system has to be integrated with other technologies such as communications and sensors, enhanced computational ability. So it becomes a living system as opposed to a dumb, dead, mechanical system.

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EC: *So there's this underlying need to get people to change their way of looking at the system. What will it take to do that?*

CG: I think it's going to take showing them that they have to re-invent their business. And I think it may start with a distribution entity and I think someone has to make the argument that in order to reinvent your business you need to get out of this trap of looking at it as a commodity delivery business and start thinking about how you deliver service to customers, to consumers of electricity.

And it may mean doing more than just selling electricity. I actually have to show the utilities how they could make money with an enhanced delivery system. And I think it starts with distribution. Once you see distribution truly become automated, it will greatly influence how the transmission asset owners view distribution and how they view how they can operate their system.

EC: *I'm just going to say here that you're looking at a bottoms-up approach opposed to a top-down approach.*

CG: Why is it there that the investor-owned utilities haven't really stepped up to use [flexible AC transmission] FACTS? Of the six major FACTS installations in the United States, five of them have been sponsored by public power entities. Well, it's a question of getting a return on their investment and assuring that there's a return on their investment that they can count on through time. So there's that and we'll continue to work that part of the equation.

EC: *How much of an investment are we talking about? I understand you are working on a new report to document your assessment.*

CG: Last summer, I threw this number on the wall of $100 billion, which I was almost sorry I did. I was in an interview, I think, with the *Washington Post*, and I mentioned this number, $100 billion dollars. Boy, all of a sudden it's all over the place. It had no substance to it at all. Prior to that the only number that had been put up on the wall at all was $62 billion that the Edison Electric Institute ferreted out.

Are those two inconsistent? Well I don't know.

I've got to believe once we enhance this electric power delivery system and we integrate it with communications and we've got local computational ability and sensors and so on, that the benefits that will flow to society are beyond the things we can even identify today.

So this new report is simply an attempt to say, "What's a reasonable number?" Let's make a bunch of assumptions, that I'm sure will be debated, and I've already been challenged even as I've used them in some speeches. We need to make a couple hundred billion dollars of investment in the transmission distribution system beyond the current rate of investment, which is pretty much just to cover load growth.

What would the value be to society if you could do that? We've estimated a number around $700 billion of value for a $200 billion investment. Not a bad deal.

Now, we can have a debate now about who's going to pay for it and how.

> *"I've got to believe once we enhance this electric power delivery system and we integrate it with communications and we've got local computational ability and sensors and so on, that the benefits that will flow to society are beyond the things we can even identify today."*

EC: *What kind of impact would it have on people to raise that $100 billion or $200 billion over a decade?*

CG: One simple estimate is to say your bill will go up ten percent in order to make this happen. That's if you made the direct investment. If you borrowed money, instead, you might only see a 3 or 4% increase. If you did some combination which involved taxes, then you could see a different number.

No matter how, the consumer will pay. We could mask it from him and do some combination of these things, but the consumer will pay roughly 10%, and I think it's worth it.

EC: *Okay. Well we have a quantifiable amount that everybody can see on their bill each month versus an out-there number that is like an avoided problem. How do we get people to be willing to make this investment for that?*

CG: Just yesterday I kicked off a study that will be done of 400 businesses and industries in the United States to try to get at this question of whether they're willing. You know, if I could assure you that I would improve reliability, that I would enhance power quality, and I may even do some other things that would give you control over your energy cost, if I could do this for you, would you be willing to pay 1%, 10%, 5%? So we need to get some idea of whether this plays with the public. Because if it doesn't, we're all wasting our time.

EC: *Okay. One would think that the August 2003 event would have been a spur to legislators actually dealing with the energy policy issues that have been out there for a decade, would have been a spur towards private investors returning to utilities as opposed to somewhere else, would have been a spur towards getting the public to say, "I don't want to go through that again."*

And yet what we see from the final report from the international investigation panel is a very limited assessment. If the operators had been trained better and if they'd been watching their computer monitors and if the computer monitors had been working properly, we might have prevented this. What's your feeling about the final report that just came out?

CG: My feeling is of those 46 recommendation points only three of them really refer to technology. But I absolutely agree with every point that's made. And yes if we have different rules and they're followed. Because right now we have rules that aren't followed.

It's very interesting if you compare this blackout August 14th with the three that were in Europe during the same summer. The Europeans followed all their rules but the rules were wrong. We didn't follow our rules, but the rules were probably right. So, if you follow the rules, those things wouldn't happen.

But the rules basically say the following: Operate exactly like this, and you will mitigate against a whole number of possible contingencies. It's not impossible that you still might not find yourself in a blackout situation, but you might mitigate the extent of the blackout and you certainly will mitigate its impact overall on society.

I think actually Recommendation #3 suggests that you consider investments in advanced technology. But it never goes on to talk about what possible positive impact they could have. So I find that a deficiency.

But otherwise it's very detailed, fine report done by some very credible people.

EC: *Where do you think the investment should go, vis a vis transmission versus distribution, versus end-user technologies? Because they all have a role.*

CG: It is clear to me that there are any number of changes that could be made on end-use equipment, energy consuming devices and appliances, that would mitigate the need for having quite the high level of reliability in digital grade power that are otherwise implied.

A small ultra-capacitor, $40 dollar device in a $15,000 lathe can save the lathe operator, or machine shop owner, a great deal of inconvenience and wasted productivity that basically insure him against the whole host of disturbances he would otherwise have seen. To me it's all under the category of hardening end-use devices.

Secondly, standards. In this country we have ten different electromagnetic compatibility standards. These are standards that relate to the radiated waves that come

continued on page 14

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from pieces of equipment. In our industries today, that lack of standards coordination causes a whole bunch of power-quality problems and these power-quality problems cause local outages or shutdowns of machinery that aren't seen by us but certainly are by industry. And they're a loss in productivity.

That can be mitigated by standards development. Let's all get together and agree. It's not expensive, it's not sexy, but it's not also being done.

And then finally I'll move to the transmission and distribution system. Ninety-two percent of outages are really distribution outages, according to a survey by Edison Electric Institute. In fact, I've referred to squirrels as Public Enemy No. 1.

There are technologies on the distribution system that can address a great deal of the local disturbances.

Transmission today is more of an issue of constraint, utilizing the asset fully, increasing power flow effectively. Lines in the West are underutilized by 20% to 30%, 10% to 15% in the East. We could squeeze a lot more out of the existing asset if we deployed advanced technologies.

EC: *What are some of the dead ends that we've come across?*

CG: I can't see the system. The best estimation technique I have for actually seeing the condition of the system in real time takes 50 seconds. Sensors gather data, they're communicated to a central point, a computation is made. Fifty seconds is entirely too long for a system that literally operates at the speed of light.

I have to be able to see it. Part of that involves communication, sensors, and a very rapid computational ability. I want to see the system literally in real time, not what they call today "real time" but literally in real time. All right, so that's number one.

Number two, once I have that information, I've got to convert it into knowledge as to how best to control it. So I need some kind of commanding control hierarchy in there.

And three, I need something to be able to control. I do need more proliferation of power electronics devices. So once I've done that, now I've got a communication system integrated with the power delivery system. I can extend that into distribution and literally at that point reach to the consumer. Things like demand response can be easily enabled once I've got that communications hierarchy in place. Helping consumers control energy costs by the use of distributed resources. I can enable all of that much more easily than I can now.

EC: *We're now beginning to get the summer assessments, and it could be touch and go in some parts of the country. What's your prognosis and is there anything that we really can do now for this summer, or are we looking at a 2-3 year kind of timeframe?*

CG: I think the audits that the North American Electric Reliability Council is doing are going to be very helpful to highlight, to control area operators any deficiencies they see in terms of the rules that we've established. Training is so important, the ability to be able to react and so on. So, those are some short-term things. That's about all you're going to do technology-wise between now and the middle of this summer.

And my prognosis is [a blackout] could happen again, and it could happen any time. It doesn't have to be hot, and it doesn't have to be obvious where it's going to happen.

The summer assessment report shows the normal congestion still in the Eastern interconnection, that same area of Ohio and broader surrounding areas, the whole section of North/South on the Eastern interconnection. There are very few major lines that move a lot of energy from the Northern part to the Southern part of the Eastern interconnection.

In the West, we have another up-spurt in the economy, and we could find ourselves in a real deficit situation.

EC: *Thank you.*

Clark W. Gellings is Vice President, Power Delivery and Markets for the Electric Power Research Institute in Palo Alto, California. Gellings holds the responsibility for EPRI's research and development programs, which include overhead/underground transmission, power system planning, substations, distribution systems, and end-user technologies.

Gellings joined EPRI in 1982, and has authored or co-authored 10 books and over 350 article or papers on electricity issues. He is a registered Professional Engineer, a Fellow of the Institute of Electrical and Electronics Engineers (IEEE), and a Fellow of the Illuminating Engineering Society (IES). He holds degrees in electrical engineering, mechanical engineering and management science.

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Contact Mr. Gellings.

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What, Me Invest?

An Examination of the Case for Transmission and Distribution Investment

by Leonard S. Hyman, Senior Consultant, R.J. Rudden Associates

Why do people invest? They wish to earn income on their investment, and they hope that investment increases in value. The combination of current income plus capital gains equals the total return. What makes the investment rise in value, other than an accumulation of retained profits? Simple: the investment must earn more than its cost of capital.

Let me clarify the type of investment I'm analyzing here. I mean typical, common stock equity investment, the money that takes the risk.

A number of financial firms intend to raise money for transmission investment in a way that may provide the investor with something that is the functional equivalent of a high yielding fixed-income security with an option on some of additional profitability. In the current financial environment, such securities would attract the attention of yield-starved institutional investors.

This type of financing, I suspect, will have use in the purchase of existing assets, but a more limited role in expansion of the physical network.

Now, let's get down to investment specifics. More studies than I can count have argued that spending on electric transmission has not kept up with demand for its services. Recently, the spending numbers on distribution have begun to sag, as well.

I will lay out why rational investors should not, and probably will not, voluntarily invest in transmission, and why distribution might stand a better chance of raising money.

Organization of Transmission

First, consider the organization of the transmission sector and then tell me, with a straight face, that it is a business.

Most transmission lines are owned by the utilities, but are under the operating control (or soon will be) of non-profit, supervising monopolies called regional transmission organizations. RTOs have no fiduciary responsibilities to the owners of the lines, as far as I can tell, and do not report to the owners of the lines or to consumers or to local regulators. They do report to the Federal Energy Regulatory Commission (FERC), which has no contact with consumers and no direct control over the local utilities. Since the lines remain in the state rate base, most of the profit earned on the lines comes from the local consumer, who may or may not benefit from their operation.

A handful of regulated independent companies own lines, but they report to the RTO in the same way as the utility owners, despite that fact that they do not have the conflicts of interest that caused the FERC to force the RTOs on the utilities in the first place. The Feds regulate these companies, though, because they no longer have assets in state rate base.

Merchant transmission companies can fill gaps in the network, put in lines where doing so would profit them. Despite the fact that the merchants receive no assurance of regulatory return, and they have no conflicts of interest, they still have to jump through all the hoops required by the FERC and the RTO.

FERC has instituted a congestion-pricing scheme called locational marginal pricing (LMP) to signal generators (after the fact) which lines are overloaded so that generators will put their facilities where the lines can carry the output.

The RTOs have instituted procedures whereby users can acquire the rights to those congestion charges, thereby protecting themselves against unexpected congestion charges because they would collect those charges back through the rights.

Presumably, owners of the congestion rights could put up merchant transmission projects that would solve the congestion problem and collect the charges, and that is the bait originally dangled in front of potential investors.

Of course, if the merchant solves the problem, the congestion charges will fall for lack of congestion, making for a poor investment on the part of the transmission builder. Proponents of the system have finally figured that out.

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So, how can a merchant finance a line and still make money? Simple: offer contracts to use it. That creates another problem, nowadays. In this age of freedom of choice, what entity could, prudently, sign a long-term contract when its own customers can walk away from it? Why is a long-term transmission contract any more prudent than a long-term power purchase contract?

Some now argue that in instances of market failure, the signals will not attract investment. The RTO will mandate the investment. Just to maintain the facade that the pricing system works for commercial uses of the lines, how about mandating capital expenditures for reliability purposes, because the market does not send signals for reliability?

Do they mean, "We won't force anyone to put up lines for commercial purposes when the market does not want them, but we will make the RTOs and transmission owners put up lines needed for reliability," or do they mean, "We'll put a reliability label on anything we want built?"

It does not matter, though, because the transmission owner (generally the local utility) will have to build. But, what constitutes a reliability investment? Every instance of unreliability has commercial consequences for users and, I suspect, the RTO, in many cases, could find commercial solutions to unreliability, such as paying certain customers to go away or to install and operate distributed generation that would mitigate the unreliability problems on the grid.

Does forced investment produce satisfactory profits?

That brings up another issue. Nobody on the grid, as far as I can make out, has the incentive to find the lowest-cost means of furnishing service to consumers. Transmission owners have no control over charges for various transmission services, many of which have skyrocketed, which will affect the demand for transmission services. Basically, they have little say about the pricing or service levels of the products they get paid to furnish.

Does that have the makings of a good investment?

Business Structures

"But somebody has to do it!" say the industry engineers. Who are the somebodies?

First, the regulated utilities – Undoubtedly, somebody will order them to do it, and they will, possibly reluctantly and possibly enthusiastically, depending on the project. They will earn what the regulator allows, assuming that the RTO operates the system in a manner that so permits.

Second, independent transmission companies – Originally, those entities thought of themselves as like National Grid or Red Electrica, transmission companies that would own and operate the grid, under a regulatory regime that encouraged them to find ways to provide services at lower costs. Those would have been real businesses. But FERC pulled the rug out from under them. Now they resemble real estate trusts, except for these two critical differences: real estate trusts actively manage properties in order to improve value, and real estate trusts lock in returns through long-term leases. The transmission companies cannot actively manage to create value and the regulator will not provide a long-term return.

"Oh, but didn't FERC offer high returns to independent companies?" the optimists ask. Yes, of course, but read the fine print. FERC did not specify the duration of the extra returns and did not specify extra over what.

> *"The industry, at present, has no way to know how much investment in transmission it really needs. It does not know, and will not know, until it prices its product in a way that reflects costs."*

Third, the merchants – So far, I think that one merchant line has gone into operation, and that only after the Secretary of Energy intervened to prevent an emergency. That line, planned years ago, depends on a contract from the user for its viability.

For all practical purposes, a utility that signs a long-term contract might just as well own the assets, because it takes the financial risk of ownership, as signers of long-term independent power producer (IPP) contracts found out when they had to buy out expensive contracts. Project sponsors have claimed the support of a number of big time bankers and investors for various projects, but the support seems more in the nature of polite interest until such time as the project has the users signed up on contract. Once that happens, the project developers can lean on the credit-worthiness of the contract users to raise money.

Regulators cannot force merchants to invest, but they can exert heavy pressure on regulated transmission owners to do so, and they seem ready to do that in the name of reliability, while still maintaining the facade of market pricing.

Repeat Performances?

Some of the transmission investors and bankers remind me of the hot shot generation builders before the crash, who depended on optimistic projections and the belief that all the other irrational players would back off and leave them with the markets. Or better yet, the energy players that went into foreign projects with only limited assurance of favorable tariffs, but with confidence that the host government would not act irrationally, that is, in a way would discourage future investments. Many foreign governments, however, figured out that once the investor had built the power plant, the investor could not move it out. The foreign governments captured the asset.

Now to another risk, similar to what happened after electric utilities built expensive nuclear power plants and discovered, after the fact, that they did not need them. The industry, at present, has no way to know how much investment in transmission it really needs. It does not know, and will not know, until it prices its product in a way that reflects costs.

> *"Financially speaking, distribution is more than twice as important as transmission to the industry."*

For instance, peak-load pricing might reduce demand at key times by enough to obviate the need for new transmission lines. Nor has the industry considered whether use of local resources could relieve strain on the network more economically than through system expansion. Furthermore, neither industry nor regulator considers whether more efficient operation of the existing network could accomplish as much as new investment in the grid.

After previous experiences involving merchant generation, foreign investment, nuclear power and price elasticity of demand, it is amazing that investors would march into the middle of a dysfunctional transmission morass.

Distribution Differs

Financially speaking, distribution is more than twice as important as transmission to the industry. Most reliability failures take place on the distribution network, so improving service to 21st century standards will require more work on distribution than transmission. In the future, any move to a market in which customers can choose services and products will require a revamping of the distribution network. The new distribution grid will require sophisticated metering, individual turn on and turn off, and placement of distributed resources.

From an organizational standpoint, distribution looks more business-like. One entity owns and operates it and answers to one regulatory agency. Legal precedents tell what to expect from regulators. Customers view the distributor as the electric company.

In much of the period during which transmission expenditures fell off, spending on distribution held up. Once utilities signed on to price freezes as part of regulatory deals, distribution capital spending began to taper off.

Now that the price freezes have begun to expire and the economy has picked up, I would expect a sharp increase in distribution spending.

If the utilities actually intend to modernize the network and improve reliability, that spending will have to include sharply higher sums for communications, metering and distributed resources. With the higher spending, expect rate filings as well. Those filings will concentrate managerial and regulatory attention back on the distribution network.

The fact that so few customers have left the utility for the competitive providers may offer a business opportunity to the utility, under the right regulatory framework. A modernized distribution entity could offer a sophisticated menu of pricing and services to the consumer, and could use its bargaining power to force better products and services from the other components of the supply chain, just as General Motors or Wal-Mart does in its markets. Regulators could reward the distributor for doing a better job for its customers. I suspect that investors would put money into utilities that make more money by satisfying customers.

Conclusion

Do not conclude that putting money into transmission has to be a bad idea, only that the current American framework for transmission seems an uninviting place for equity money, although it might provide opportunities for those seeking high return securities with fixed income characteristics.

As an equity investor, I do not see it as a business, and I would prefer to gamble on something that provides more fun or make charitable contributions to a worthier cause than to invest in a non-business.

I see greater opportunities in modernizing the distribution network business and in services that mitigate deficiencies of what the transmission network provides. But even those businesses require recognition from regulators that the purpose of the electricity delivery system is to provide consumers with the best products at the best prices, and those in the supply chain must all get paid on the basis of whether they have helped to meet that goal. □

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Will Incentives Get More Transmission Infrastructure Built?

by Robert W. Gee, President, Gee Strategies Group LLC

The power blackout of August 14 of last year was a wakeup call that something is seriously amiss with the country's electric power delivery system. Although an exhaustive government-led investigation concluded that the immediate cause of the blackout that day was largely due to ineffective and uncoordinated reliability management of the grid – along with poor vegetation management – knowledgeable observers have indicated that this incident also underscores a long-festering concern of hard asset adequacy given the system's fragility and lack of resiliency. No doubt the overarching policy issues of sufficient reliability standards, along with proper grid supervision and control, will continue to dominate discussion in courts, regulatory arenas, and Congressional cloakrooms. But it is unlikely during the interim that significant amounts of capital will be invested to enhance the means by which power is delivered to homes and businesses.

This is a serious problem. The growth of electricity demand in our economy, which over the years riveted our attention and resources to encourage newer, cleaner, and more efficient power generation capacity, has left an insufficient commitment of capital in the transmission segment of the power delivery business. Further exacerbating the situation, the breakup of the "family of assets" that used to reside under the traditional, vertically integrated utility in many venues has left – if not an abandoned orphan – something akin to a neglected, transmission stepchild. Having exercised poor parental supervision, we're now paying a price.

The solution offered in some circles is to reinvigorate investment by offering incentives to invest. Such incentives can take several forms. One approach would be through assignment of a reward premium to the utility's regulated equity rate of return. Typically, rates of return are awarded based on, among other things, references to comparable investment alternatives. Equity returns also are a function of anticipated costs of money over the foreseeable time period. The rationale behind assigning a premium to an authorized return rests on the premise that "business as usual" will not suffice to jump-start the type of management and investor behavior needed to address critical gaps likely to widen for the foreseeable future.

This type of incentive approach would be legislatively authorized by the House of Representatives' version of the energy bill still pending in Congress. Without specificity, it directs the Federal Energy Regulatory Commission (FERC) to utilize rate incentives. Additionally, a similar recommendation appeared in a report issued last year by one foundation-funded, blue-ribbon panel. The National Commission on Energy Policy called for "higher rates of return for approved measures, increased certainty of recovery, and performance-based rewards that share system savings between shareholders and users" to address inadequate investment in transmission.

This was the apparent reasoning of the FERC last year when it proposed adopting a policy to allow transmission-owning utilities to enjoy, for new transmission investment, a generic one percent mark-up to the customarily set equity rate of return. The FERC also proposed awarding additional return premiums of one half a percent for companies that participated in Regional Transmission Organizations (RTOs), and one and a half percent for RTO participants who meet certain independent-ownership requirements. The transmission investment incentive was part of a broader package of "carrots" designed to encourage voluntary structural reform of the firms who own and operate the grid.

Predictably, FERC's generic rate mark-up proposal has been lauded by most transmission-owning utilities, and sharply criticized by consumer advocates, commercial and industrial consumers, and some public power entities who are dependent upon transmission-owning utilities to deliver them power. Among their objections: current returns are ample to incentivize investment; this measure would be ineffective since transmission constitutes only about 10 percent of total grid assets, with the remainder under retail state jurisdiction; a reward premium would unjustly enrich utilities for making investments they are already legally required to undertake; investment rewards should be targeted only to those that remediate congestion; and enhancing the certainty of cost recoupment is the real issue, accomplished by allowing the current rate recovery of precertification expenses.

Were we in a purely business-as-usual setting, some of these objections would undoubtedly have merit. However, FERC's approach has logic when coupled with its rate incentives for structural reform regarding RTO membership and independent ownership requirements. Above all else, uncertain regulation currently stands as the paramount obstacle impeding new investment. Irrespective of whether one agrees with FERC's philosophical direction in striving for greater uniformity of market standards, the greatest weakness impeding investment has been the fundamental failure to provide the vision of an end-state for the grand experiment called restructuring. If financial incentives could accelerate structural reform and enhance regulatory certainty, and if any significant new investment could be encouraged, the fiscal impact on ratepayers may be worthwhile relative to the total cost of delivered power since transmission makes up only about 10 percent of that cost.

Additionally, the incremental cost from adjusting an equity return may pale when contrasted with what ratepayers already pay from the current cost of power failures. In an oft-cited survey conducted in 2000, the Electric Power Research Institute (EPRI) found that the country's annual exposure to power outages and disturbances ranged from $120 billion to $180 billion. If correct, consumers already pay this annual sum because these costs are absorbed in the form of higher costs for goods and services

One objection to FERC's proposed incentives for new investment, RTO membership, and transmission asset divestiture is that the cumulative cost to consumers could be as high as $13 billion over the duration of the incentives. As the EPRI survey demonstrates, cost exposure to that sum over a multi-year period could be dwarfed by the annual cost savings capable of being realized from improved reliability, and lessened outages and disturbances.

FERC has not offered up a silver bullet. It has, however, spawned a vigorous debate over how much we value reliability, what we (as a country) would be willing to pay for it, what steps we should consider to move us forward, and at what price we might ultimately concede that something – anything! – must be done.

Other incentives or mechanisms may have better merit than FERC's proposed prescription. But today's lesson should be: out-of-the-box thinking got us in the jam we are today, and most likely only out-of-the-box solutions will get us out of it.

Incentives aren't the ultimate answer, but they need to stay on the table. □

about the author

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Bulk Power System Reliability

A Case for Industry Self-Regulation

by Richard Barker, President & CEO, Quad Resources, Inc.

Although there seems to be general agreement that the bulk power system needs better enforcement of compliance with reliability standards and operating policies, there is disagreement over whether the enforcement authority should reside with the industry itself or with the federal government.

At present, the North American Electric Reliability Council (NERC) is the organization whose mission is ensuring that the electricity grid is reliable, secure and adequate. NERC is a voluntary organization consisting of representatives from utilities, control areas and interconnections which operate the grid. It is an industry group.

In its role, NERC develops operating guidelines, procedures, standards, policies and other rules of the road for operation of the interconnected bulk power system. NERC has no enforcement authority per se. It depends entirely on voluntary cooperation among its members to fulfill its mission, while peer pressure, reciprocity, mutual need, mutual benefit and other such forces reinforce members' incentive to cooperate.

The report on NERC's investigation into the causes and contributors to the 2003 Northeast and Midwest Blackout very candidly points out not only failures of transmission operators to comply with NERC standards, but failures of NERC to monitor and ensure compliance.

It also identifies a lack of uniformity in interpreting standards, inconsistent application of protection technologies, less-than-adequate sharing of planning information, out-of-date modeling data and failures to apply lessons learned from previous blackouts. All of these point not only to a need for better enforceability, but better cooperation among NERC members in planning and operating their individual pieces of the bulk power system.

Historically NERC and its members have done an excellent job of managing and regulating the grid. But recent changes in federal regulation have made NERC's job much harder than it once was. Open-access regulations now require transmission owners and operators to open their systems to use by other entities, including many non-utilities. Many of these new entrants have little or no experience in bulk power system operation, and little incentive to cooperate with other owners and operators, their interests being more oriented toward the commercial rather than the technical. So what once worked quite well has been seriously compromised by changes in federal regulation.

Further, NERC itself has departed somewhat from the purpose for which it was originally organized. NERC initially concerned itself strictly with the grid's integrity, reliability and stability. Today's NERC is as much concerned with political and market issues as it is reliability, thereby diluting its effectiveness.

The failures identified in the NERC investigation suggest a new, more comprehensive role for NERC or some other NERC-like organization. In its report, NERC makes fourteen recommendations, many of which imply greater activism on NERC's part.*

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected.

Legislation to grant NERC this enforcement authority and then allow NERC to do its job is perhaps a good idea. Legislation that creates a new federal agency or new federal powers to define standards and policies or to enforce compliance is not.

Legislative proposals seldom survive intact. The enabling legislation approach to enforceability runs a risk that the resulting legislation will be something altogether different than what NERC needs. Nevertheless, if NERC can get the enforcement authority it needs, legislation may be a good solution.

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As for the potential success with voluntary compliance, there is an organization within the electrical industry that has achieved great success and effectiveness with voluntary compliance. The Institute of Nuclear Power Operations (INPO) is an entirely voluntary organization to which all nuclear plant operators in the United States belong and support.

INPO does more than establish operating policies and guidelines. It also conducts nuclear plant inspections, applying a rating to each facility. INPO regularly borrows personnel from nuclear plants to assist in inspection and audit activities at other facilities, and also lends personnel from its own staff to fill vacancies in operators' facilities. This interchange of personnel promotes the exchange of ideas and expertise and allows operator personnel to gain understanding of the regulatory world while ensuring that INPO personnel have real-world experience. It also facilitates the exchange of information among the nuclear operators themselves, assuring uniformity in interpretation and application of policies and procedures.

Like NERC, INPO depends entirely on voluntary compliance of its members. The big difference is that voluntary cooperation at INPO works. Why? What are the incentives?

First, nuclear operators are keenly aware that a major incident at any one nuclear plant will have serious consequences for all plants. So it is to everyone's benefit to cooperate. In fact, anyone refusing to cooperate would put all in jeopardy. Another incentive is that of insurance. A favorable INPO rating means lower liability insurance costs. An unfavorable rating will have the opposite effect. So there is a very real financial incentive to voluntarily cooperate and comply. Indicative of INPO's success is the reduction of NRC on-site personnel at many nuclear facilities in the U.S.

Admittedly, in the world of bulk-power system operations, the stake in mutual cooperation is not as high as it is in the world of nuclear operations, but there are, or should be, some very definite incentives. All operators depend on the reliability of the grid, and all are at risk if the grid is not reliably operated.

These risks are both financial and regulatory. From a financial perspective, everyone connected to the grid will suffer if reliability is inadequate. Continued reliability problems will no doubt result in federal action and costly new regulations which will likely make matters worse than better.

So what can NERC do to reinforce cooperation and compliance?

A regular NERC inspection program with visiting or even, in some cases, resident NERC advisors will serve to keep compliance issues on the front burner among NERC members. A rating system similar to INPO's would serve as a quick indicator of a system's reliability.

Interchange of personnel and data, including information about problems, potential problems and solutions, would help strengthen cooperation and promote uniformity of understanding and application of NERC policies and guidelines.

Enforcement of stronger, more uniform terms and conditions of service for new entrants to transmission access should make NERC oversight and compliance a condition for use of the open access transmission system which would, in effect, force new entrants to comply.

NERC should advise complying members of neighbors who fail to comply, such advisories allowing them to take the actions necessary to protect or immunize their own systems against problems in the uncooperative system – sanctions, as it were. Among these actions would be setting relays and configuring systems to more quickly disconnect and isolate the offending system during major disturbances, thereby protecting the rest of the grid from the problems on the non-complier's system. Grid reliability would improve, while reliability of the non-conforming system would decrease.

Finally, publicizing NERC's activities, ratings and the results of its inspections, including information regarding systems which are found to be in non-compliance, along with the actions taken against them, will exert tremendous pressure from the public, state regulators and legal counsel to resolve the problems.

NERC's seeking of enabling legislation is one approach to solving the enforceability issue. There are risks. A return by NERC to its original purpose, and a more aggressive approach to voluntary compliance is another. Either, or a combination of the two, can obviate the need for a new federal electric reliability agency and all the potential problems and costs that would no doubt entail.

There can be no doubt among those who understand the grid that industry solutions will be far less costly and more effective than federal solutions. Whatever is done should be done quickly before another incident like the one on August 14, 2003, gives the politicians the additional ammunition they need to force a federal "solution." □

* August 14, 2003, Blackout: NERC Actions to Prevent and Mitigate the Impacts of future Cascading Blackouts — February 10, 2004

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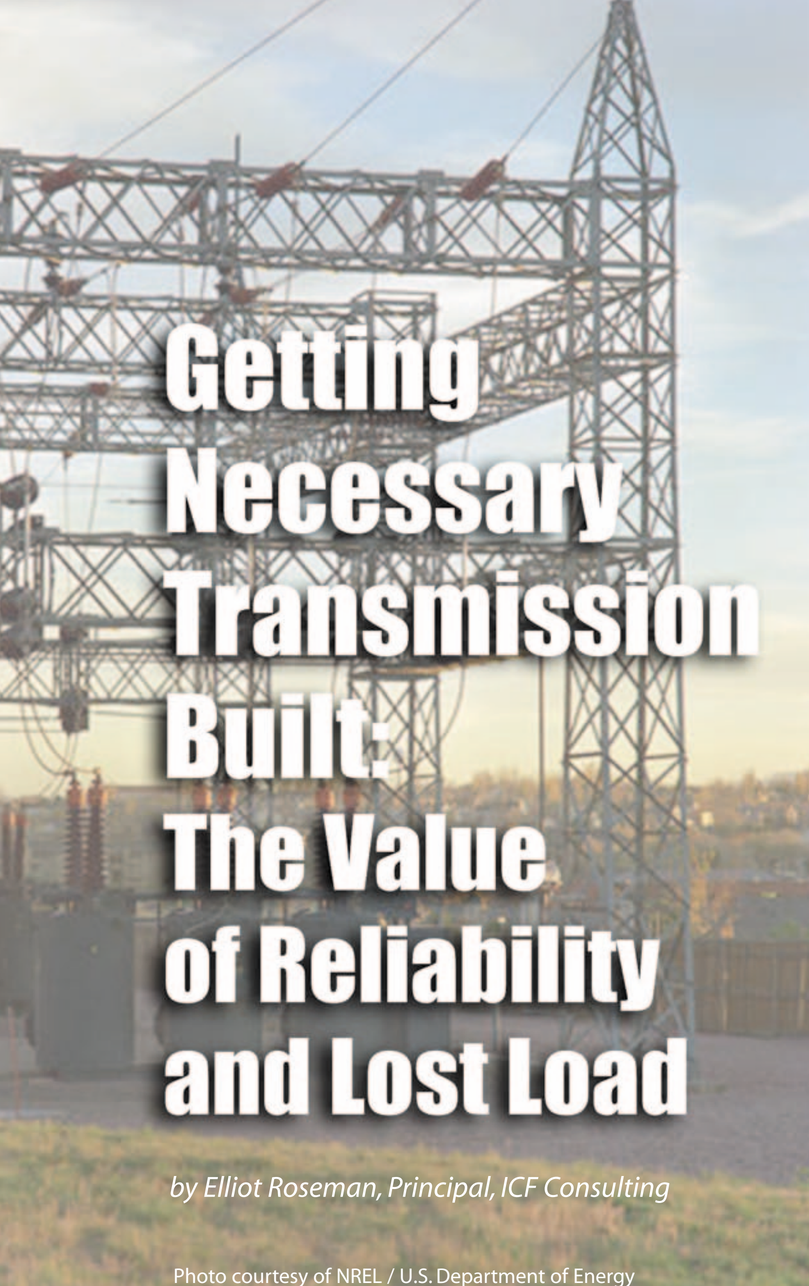

Getting Necessary Transmission Built: The Value of Reliability and Lost Load

by Elliot Roseman, Principal, ICF Consulting

Photo courtesy of NREL / U.S. Department of Energy

The power grid in the U.S. is highly reliable; most utilities provide power well above 99% of the time. But every so often, and with increasing frequency, we are faced with temporary outages, extended blackouts, flickering lights and dark computer screens. These glitches in the operation of an otherwise sound power system are the results of years of inadequate investment in our electric transmission and distribution systems.

When the power is out, economic activity quickly grinds to a halt. This is increasingly so as we become more dependent on power due to computers, rechargeable mobile telephones and other equipment, particularly in formerly off-peak times. Unless an outage is truly short term, the consequences are non-trivial: the contents of our refrigerators may defrost and spoil; all of our business (from office buildings to shopping malls to hotels to fast-food establishments) shut down; industrial companies can lose entire production lines or hours of lost output; and hourly workers may lose substantial wages. Once they occur, most of these losses are not recoverable.

The cost of such outages is substantial. According to the Electric Power Research Institute (EPRI), roughly 2 million businesses have been losing $46 billion per year in lost production due to power outages and another $6.7 billion annually due to power quality issues (e.g., voltage fluctuations), for a total of more than $50 billion per year.

ICF estimates that the economic impact of the August 14, 2003, blackout was $6 billion to $10 billion. Further, we calculate that the average cost of transmission-related outages alone over the past 5 years has been $12 billion.

So there is substantial room for improvement.

ICF recently completed a major study sponsored by Kohlberg Kravis Roberts and Company (KKR) in which we determined that strategic transmission investments of about $8 billion (net present value) over the next 26 years could lower the wholesale cost of power by much more than the cost of those investments. Also, in the KKR study, ICF determined that these investments would have benefits of about $60 billion (net present value), approximately 8 times their cost, in savings to the economy from potential reductions in transmission-related outages.[1]

Clearly, the value of power (also called the "value of lost load" or VoLL) is much greater than the price we are charged for this service. Simply dividing the total U.S. GNP of $10.6 trillion in 2002 by the total number of GWh consumed (3.46 billion) implies an economy-wide value of electric power of $3.06 per kWh. Research carried out largely in the 1990s by a number of utilities revealed that the economic value of power is greatest in the commercial sector, where the opportunity to recover lost revenues incurred when the power was out is small.[2]

These studies also found that the multiple of the value of power over and above the tariff amount charged by utilities (the "VoLL multiple") ranges from 50 to 120 times, depending on the sector.

Increasingly, these events are not momentary outages, but rather extended blackouts that reveal the stress under which the transmission and distribution grids have been placed in recent years. Wholesale power transactions canceled due to overloaded lines rose five-fold from 1998 to 2002. Congestion is the "cholesterol" of the transmission system; it blocks the power arteries and puts stress on the system that can contribute to a major breakdown.

To avoid or recover such costs, some parties have sued those they believe responsible for outages such as the August blackout to recover their lost economic value.

But litigation is not the answer.

The cost of a system that would be close to 100% reliable, with virtually no outages or power quality issues, could be prohibitively expensive.

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But if not litigation or massive investment, what would it take to avoid these very real economic costs? The answer: Strategically targeted transmission investment.

> *We need to identify and make investments in transmission over and above the amount required to maintain current levels of reliability, both to lower the wholesale cost of power, and importantly, to reduce the economic impact from transmission-related outages.*

With over $50 billion per year in economic activity at stake, one could justify building upgraded transmission lines, expanded rights-of-way, better monitoring equipment, substations and distribution reinforcements, and increases in tree-trimming budgets, thus mitigating much of the problem. Fortification of the transmission system could be completely paid for through the savings realized in economic output alone in just one year, even if one places no value at all on the massive inconvenience for customers whenever a major outage occurs.

The problem is, however, that the way in which we evaluate and justify the cost of building new transmission and distribution has nothing to do with measuring the economic impact of the outages that may occur. It's simply not part of the equation.

Moreover, it is hard to win approval for transmission in particular due to the difficulties in obtaining or expanding rights-of-way. Further, there is a process that has been played out for the past several years to try to assign the cost of new transmission to parties other than the utility (e.g., an independent power producer) if the investment will support a private transaction rather than a reliability improvement.

While reasonable in principle, the difficulty with the "participant funding" approach is that many transmission investments have both private and reliability benefits, so it is tough to determine how to "split the transmission baby", and the relative importance of these two approaches to valuing transmission may shift over time. This process of determining cost responsibility for upgrades has further delayed some needed transmission, and a number of utilities are operating perilously close (or for brief periods, beyond) their operating limits while waiting to determine who will make needed investments and incur those costs.

Thus it appears that we are evaluating the need for new power sector investments too narrowly. As a society, we need to find a way to incorporate the economic value of electric power into our calculus of whether and where to build new facilities. The utilities need to have a new paradigm that requires them to consider both the reliability of the system and the economic value of making incremental infrastructure investments. They should be compensated for investments made on that basis.

We need to identify and make investments in transmission over and above the amount required to maintain current levels of reliability, both to lower the wholesale cost of power, and importantly, to reduce the economic impact from transmission-related outages.

State regulators should require utilities to add new criteria to evaluate the current and future level of potential outages and determine the economic value of lost load. This measure should be incorporated when developing resource plans and determining the new facilities that they believe should be built.

Utilities must not be discouraged from being efficient. There should be incentives for increasing reliability and penalties if reliability decreases from recommended levels. For a period of time, utilities and non-utility developers of transmission should be given incentives for reducing the economic costs of transmission-related outages.

If the current state regulatory system does not do so, the Federal government should step in to require the building of key transmission lines on the basis of both their economic value and the enhancement of national security. This idea parallels the provisions in the Energy Bill that was not passed recently pertaining to "backstop" authority for FERC to build "national interest transmission corridors."

The U.S. economy and the power system are increasingly synonymous. Investment in the electric transmission system has been sub-optimal. Performance should therefore be linked through the companies that provide transmission and through the regulatory process by taking into account the Value of Lost Load in making resource decisions. □

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[1] We note that in ICF's analysis, this strategic transmission investment would be incremental to transmission investments made to maintain current levels of reliability and investments made in power generation to satisfy growing demand.

[2] Some studies showed that the longer term (as opposed to momentary) value of unavailable power to the commercial sector can range from $10 to $20 per kWh, compared to $3 to $5 per kWh in the industrial sector and $1 to $2 per kWh among homeowners, while others showed closer cross-sector numbers.

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about the author

Elliot Roseman is a principal with ICF Consulting in Fairfax, VA, with 25 years experience in the energy industry. He works closely with public and private clients on key issues relating to electric transmission, industry restructuring, regulation and corporate strategy. He has been published widely and speaks regularly to industry groups.

SCADA in the Energy Industry — A Janus View

by Chuck Newton, President, Newton-Evans Research Company

The worldwide application of supervisory control and data acquisition (SCADA) technology has been ongoing for nearly 40 years. By now, midsize and larger utilities and pipelines throughout the world have implemented several generations of SCADA systems installed in control centers and field-based data acquisition equipment.

Newton-Evans Research Company conducted its first comprehensive studies on the use of SCADA technology in energy industry applications for power delivery, gas utilities and petrochemical transmission pipelines in 1983. In the intervening 21 years, a great amount of SCADA related development has occurred from a technological standpoint to be sure. However, we cannot overlook the impact on newer applications from external development such as the major regulatory changes affecting industry structure, the impact of the looming energy bill, standard market design initiatives and ramped-up security concerns.

The use of one or more types of control systems in modern electric utilities and energy pipelines is extensive, if not pervasive. This is true for the industrialized West and for the developing nations of the world. Around the world, there are more than 4,000 viable electric power utilities, managing as much as 30 million kilometers of power lines. There are thousands of liquid and gas transport pipelines operating nearly two million kilometers of large diameter pipe. There are more than one thousand gas utilities responsible for more than three million kilometers of distribution pipelines. The global energy industry spends more than one billion dollars each year to maintain, upgrade and replace the installed base of SCADA technology.

The initial waves of utility automation during the late 1960s through the late 1970s helped to resolve many of the then paramount technical operating issues for larger electric and gas utilities and energy pipeline operators. These included the monitoring and control of electric power transmission and delivery – plus similar transport and delivery applications in the pipeline business – leading to sophisticated algorithmic-based applications software that enabled power utilities to determine unit costing, provide transmission network security, and provide for interchange transactions and transmission load-flow studies.

In the electric power field, these early developments were led by the precursor systems integration arms of today's industry giants: ABB, Areva, GE and Siemens. In the pipeline industry, early approaches for load balancing, batch tracking, leak detection and other applications were taking root, spearheaded by such companies as Amocams, Foxboro, Tejas and Teledyne.

The next wave of SCADA related automation came during the late 1970s to early 1980s when distribution electric and gas utilities made widespread use of distribution SCADA systems, typically supplied by SCADA specialists who understood distribution applications. Companies such as Advanced Control Systems, QEI, Tejas (now Telvent) and Landis & Gyr (now part of Siemens Power T&D) developed and continued to serve the energy distribution systems market. Other early suppliers included Sangamo/Weston and Leeds & Northrup and Moore Systems.

There are several ways to look at the changes that have occurred and continue to occur in the development of the SCADA related systems marketplace. Some of these include the operating environment, the applications, the systems costs, the extent of coverage, the platform architectures and the communications methodologies and protocols. Each of these has undergone significant, if not radical, change over the past 20 years, and each continues to be rethought as we move forward.

Operating Environments and SCADA Platforms

By 1984, the majority of SCADA systems were operating in a "closed" proprietary operating environment. Very little SCADA operating information was exchanged with, or made available to, groups outside of operations, with the exception of engineering departments. By 1994, changes occurred as newer technology enabled broader information sharing, and as end-users began to realize and seize upon the extensive wealth of information available in the SCADA data repositories of the time. Most utility operations managers were sufficiently concerned with security to limit direct access to their real-time mission-critical systems, instead providing downloaded, read-only access to historical information gathered from their systems.

Platforms from the late 1960s were largely mainframe computers operating proprietary systems supplied by IBM and Control Data Corporation. With the development of very large scale integration (VLSI) circuitry, the 1970s and 1980s evidenced the widespread use of super-minicomputers, supplied by companies such as Control Data, Harris Corporation, Digital Equipment, Modcomp, SEL, Data General, all then still based on closed operating systems.

By 2004, the control center world has largely evolved to enable access to selected operational data via secured intranet for utility and pipeline operations, engineering, metering, IS and other internal personnel, as well as to key customers. In light of today's global cyber-security concerns with energy infrastructure operations, many utilities and pipelines that had been persuaded to move to partially or completely open environments have been re-evaluating such decisions.

Internet accesses, open protocols and wireless access to data acquisition units have the potential to increase vulnerability of SCADA systems. However, some of these concerns are currently being addressed by use of multi-tiered passwords, and development of sophisticated encryption and authentication techniques.

Applications Developments

In 1984, the real concern among power utility operations managers was monitoring and controlling key transmission and key distribution substations. Pipeline operators needed information from their pumps and booster stations. Utilities with power generating facilities also were linking up with in-plant DCS systems where installed, or otherwise adding automatic generation control (AGC) signaling applications to their SCADA applications library. Suppliers continued to focus on improving remote site data acquisition and control methodologies.

By 1994, the need for a worldview of operations had been established, with an eye among many power utility operations managers to acquire operating data to MV substation level and outside the fence. The use of intelligent electronic devices (IEDs) first appeared about this time. Network modeling, loading profiles, usage patterns and the like had been developed for power networks and for pipelines.

Currently, these have been refined and updated to work in more competitive market environments, in both the pipeline and power fields, and work is underway to improve SCADA data security. An awareness of the evolving open market, the energy industry's relationship with power marketers and traders, the make/buy decision-making process largely occurring in electric power control rooms, and the concern with customer premises activities, are all having an impact on near-term developments within the systems integrator community. For gas utilities, increasing demands from the AGA and federal regulators on supply sourcing will require a vendor focus on development of software resolutions to these issues.

Across the board in the 1990s, additional changes were underway among users and vendors, driven by developments in the computer and communications industry, as more and more IS managers demanded to be free of vendor proprietary operating systems and communications protocols. As such demands flowed over onto the SCADA community, large and mid-size systems moved to UNIX platforms, while smaller systems attempted to work with the early versions of Windows NT.

Defacto industry standards for open protocols evolved, such as DNP in the electric power community. Internationally the IEC communications working groups formulated widely implemented protocols for SCADA and substation environments. ICCP was developed to facilitate peer-to-peer interchange of data among utilities, and between utilities and ISOs and RTOs. EPRI and the industry developed the U.S. flavored UCA/MMS.

What the Future Holds

Over the next few years the industry focus will be on increasing the ability of users to secure their SCADA systems through the use of virtual private networks, encryption, authentication and participation in a number of task forces and working groups set up in the energy industry.

Outside of a relative handful of utilities and pipeline operators, we still don't get it, when it comes to the issue of infrastructure cyber security. Limiting access to business records and files is vital for any organization. Limiting access to real-time, mission-critical computer and communications systems typified by SCADA technology is paramount to the continued safe and secure operation of the world's power grids and energy pipelines. The passage of a comprehensive energy bill in the U.S. will undoubtedly have a significant impact on the next generation of SCADA-based technology developments. □

about the author

Chuck W. Newton is the President of Newton-Evans Research Company, a Maryland-based researcher of technology trends affecting operations of the world's primary energy industries. Prior to forming Newton-Evans in 1978, Chuck worked at General Electric and at Control Data Corporation. Mr. Newton earned an MBA from Loyola-Baltimore and a BA degree from Fordham University. Chuck's professional memberships include CIGRE, IEEE Power Engineering Society, ENTELEC, UTC, AMRA, AWWA, AMA, and CASRO.

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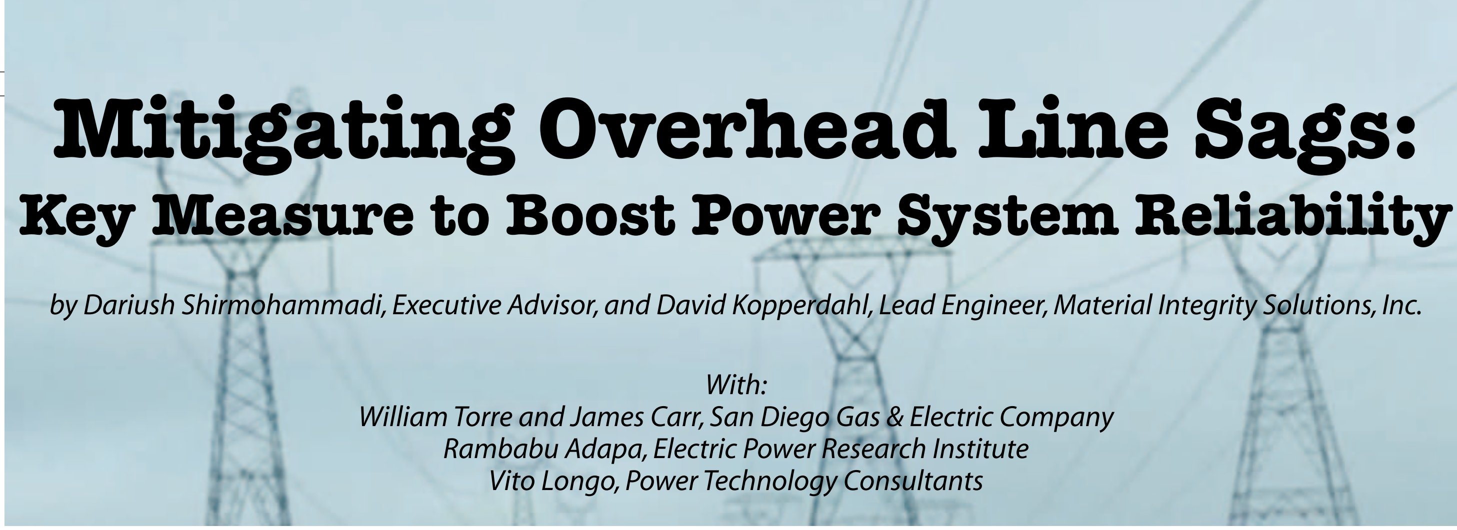


Mitigating Overhead Line Sags:
Key Measure to Boost Power System Reliability

by Dariush Shirmohammadi, Executive Advisor, and David Kopperdahl, Lead Engineer, Material Integrity Solutions, Inc.

With:
William Torre and James Carr, San Diego Gas & Electric Company
Rambabu Adapa, Electric Power Research Institute
Vito Longo, Power Technology Consultants

Excessive transmission line sag is one of the most prevalent causes for limiting the line ampacity and has reportedly resulted in numerous power system outages, particularly for line rating of 230kV and below. Thermal expansion of the conductor resulting from high ambient temperatures, low winds, and high line current can lead to excessive line sag. Increases in demand, especially on hot summer days, increases the likelihood of excessive sag and the associated reliability issues.

Utilities have traditionally implemented two classes of solutions to deal with this problem. The first class aims to limit conductor temperature rise by:

- Implementing operating measures to reduce power flow in the affected line;
- Reconductoring the affected line with a conductor of larger cross-section; and
- Building a new line "in parallel" with the affected line.

All these solutions deal with the root of the problem and, except for the first listed, they do not require constant monitoring and specific maintenance activities and costs. However, all come with a very high opportunity or actual costs.

The second class of solutions deals with the outward symptom of line sag:

- Raising tower to compensate for the excess sag;
- Adding intermediate towers at key line locations to increase ground clearances; and
- Managing objects underneath line spans such as vegetation management.

The first of these two measures is both expensive and can be impractical in areas where height of transmission towers can become the source of other complications. The latter measures are the most common approach to keeping lines clear of underlying objects.

However, each has its own limitations, including frequent and expensive monitoring and maintenance. Even the complete removal of all underlying objects will not resolve the harmful clearance problems created by excessive line sag.

SLiM: A New Approach

The newest device to mitigate line sag (hence commercially called the Sagging Line Mitigator or SLiM) deals directly with the cause of the line sag: line elongation due to rising conductor temperature. SLiM installs in series with the line and becomes shorter as the conductor temperature rises due to high current flow and ambient conditions.

SLiM maintains a nearly constant effective line length and sag within the span as conductor temperature rises. Its benefits include low cost, passivity and practically zero maintenance.

The concept behind SLiM (i.e. shortening the line length during high temperature conditions by use of special materials) has been around for a number of years. However, earlier embodiments proved impractical and unreliable because of limited range of operation and high potential for fatigue failure.

The SLiM design and embodiment was invented and prototyped by Material Integrity Solution of Berkeley, CA, with partial funding from the California Energy Commission (CEC) and the Electric Power Research Institute (EPRI). After going through extensive functionality and reliability testing at a utility and at independent laboratories, SLiM is currently going through a final demonstration stage at San Diego Gas & Electric.

As conductor temperature rises, the "Actuator" within the SLiM device, which consists of a "Shaped Memory Alloy ", contracts. This action requires the Actuator to heat up as the conductor's temperature rises due to current flow and ambient conditions. For this purpose, some or all the conductor current is directed through the Actuator. Finally, the Lever in SLiM will amplify the Actuator's contraction and provide for an effective reduction in the length of the conductor within a span.

The pre-production model of the SLiM device was designed to "reduce" the conductor length by as much as eight (8) inches. This reduction in length translates into a large decrease in sag (magnitude depends on span configuration and conductor type). A reduction of about 4 feet in sag was achieved for a 500 ft tower span during the functionality testing at the Pacific Gas & Electric Company.

As conductor temperature returns to normal, SLiM returns to its original shape, preventing excess tension in the line, and readying the device to respond to the next conductor temperature excursion.

By using a simple, passive, and reliable construction, SLiM has been designed to have a very long life and remain virtually maintenance-free. Its use of industry standard connectors allows for installation by linemen at any span. Since the device was designed to be installed similar to "splicing technique", it can be installed using live-line procedures. Its operation is also adjustable to match specific line and configuration requirements.

Functionality Testing

The SLiM device went through full scale functionality testing at the PG&E facilities in July 2002. The tests were conducted on two 500' spans (a control-span and a test-span with one SLiM device) of 795kcmil 54/7 ACSR (condor) conductor operating at 5000lbs and 90oF. Conductors were heated by a current of up to 1200A. The sag differential between the two conductors at a maximum temperature of 210oF was ~4'. Results from these tests have shown that SLiM can eliminate excess sag problems.

Reliability Rating and Simulation Studies

In addition to the functionality testing at PG&E, the following series of reliability tests and simulation studies were performed on SLiM at various facilities including Kinectrics Lab (formerly Hydro Research Division) and IREQ (Hydro Quebec Institute of Research):

- Electrical connection testing
- Corrosion and fatigue
- Short circuit testing
- Mechanical stress testing
- Electromagnetic transient (EMTP) studies
- Dynamic (vibration) studies using Finite Element Techniques

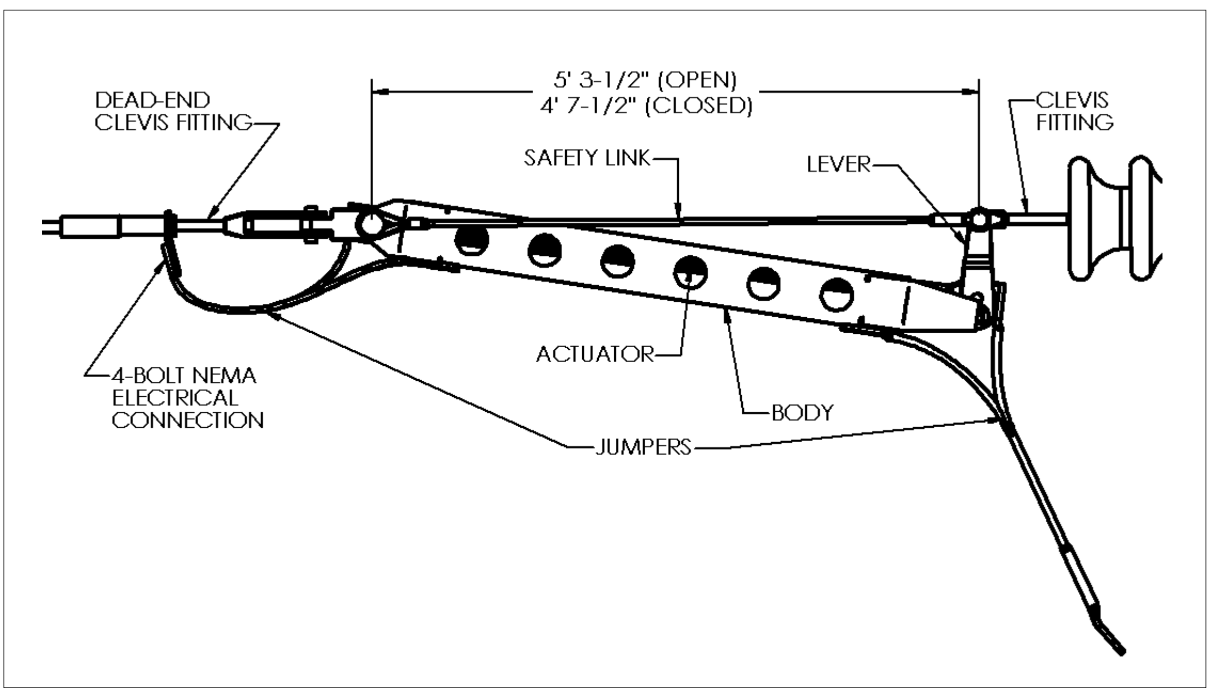
These tests/studies have all shown that the device is reliable for its intended applications and will have no negative effects on the line's electrical or mechanical performance.

Possible SLiM Applications

A high-voltage system contingency situation (i.e., outages on one or more lines) can cause loading on nearby lower voltage lines that exceed their established thermal limits. These limits are normally established to maintain conductor-to-ground clearances. Thus, the action of SLiM, which mitigates the usual sag caused by high temperature operation, can allow for safe line operation during the contingency situation. Line capacity is increased by allowing operation beyond conventional thermal limits. And, expensive line modification projects to address such contingency operation may not be averted or delayed.

Many older lines were constructed to 120°F maximum conductor temperature operation. Studies have shown that SLiM can enable operation of such lines at a conductor temperature exceeding 200°F without compromise of line clearances, tensions or integrity. This can represent a multi-fold increase of rated line capacity.

System planning may project that certain lines will become overloaded as local growth increases demand. In this instance SLiM can delay the need for either a new line or considerable line modifications while the anticipated load materializes.

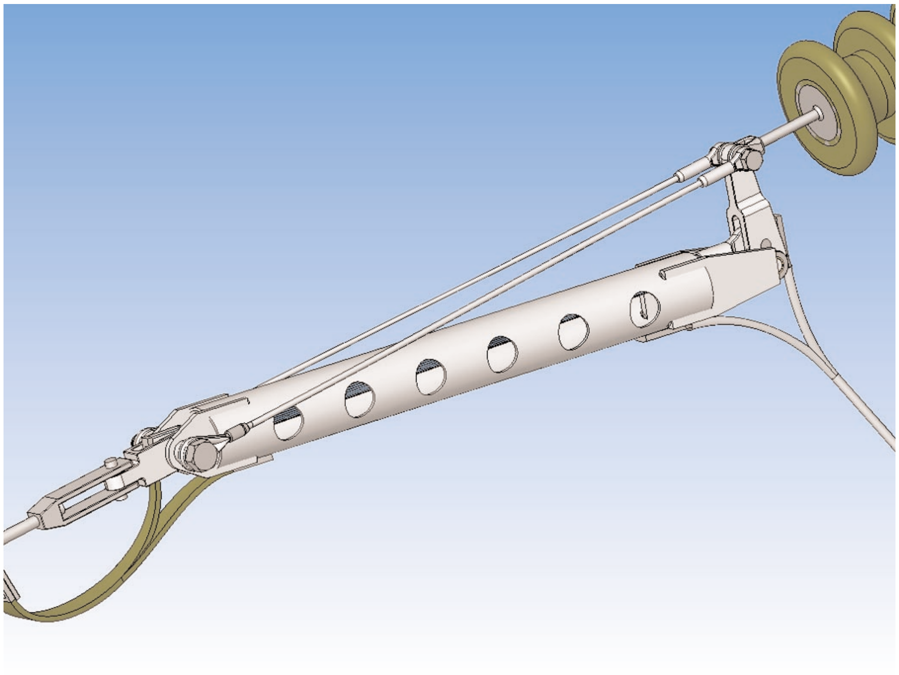


SLiM Schematic.

Demonstration

Under the sponsorship of EPRI and in Tailor Collaboration with several participating utilities (British Columbia Hydro, Consolidated Edison, Pacific Gas & Electric, San Diego Gas & Electric Company, Southern California Edison, Public Service of New Mexico, Northeast Utilities and National Grid) SLiM's performance will be demonstrated on up to three operating transmission lines. The number of demonstrations will depend on the number of project funding utilities.

The project is intended to provide participating utilities with first-hand information on the operational performance of this new kind of line hardware device. The demonstration is designed for operation during one "hot" season. The length of the trial can be extended, if necessary, with cooperation of the host utilities.



SLiM Device.

The project will compile practical "engineering-type" information to aid utilities in designing, specifying, installing, inspecting, and maintaining these devices. The results of this project will position participating utilities as informed buyers and users of this new technology.

The project will answer such questions as:

- How is SLiM best applied on a line with high temperature sag problems?
- What are relevant design parameters for SLiM application and use?
- Are there differences between real line installations and prior tests of SLiM?
- What, if any, additional special installation considerations are necessary for SLiM?
- Are there limits to SLiM applications?
- What are installation, operation, and lifetime costs of using SLiM?
- Are special inspection or maintenance methods necessary?

The project was initiated in June 2003 and is expected to be completed by March 2005. The first demonstration will take place at SDG&E and is expected to complete by the end of 2004. □

Comment on this article.

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Dariush Shirmohammadi is the Executive Advisor to Material Integrity Solutions, Inc. of Berkeley, CA. He is also the Chief Consultant with Shir Power Engineering Consultants, Inc. of Beverly Hills, CA, where he offers business and technical consulting on designing and implementing electricity markets and on improving the reliability of the electric power systems. His 27-year tenure in power industry includes positions as Senior Vice President and Head of Americas Energy Markets with OM, a Managing Consultant with PA Consulting Group, the Director of Emerging Energy Market Services with Perot Systems Corporation, and the Director of Energy Systems Automation Group with Pacific Gas & Electric Company. Dariush has authored numerous technical papers and has lectured in academic, industrial and regulatory forums around the world. Dariush has a Ph.D. in Electric Power Engineering from the University of Toronto and is a registered professional engineer. He is also a fellow of IEEE.

David Kopperdahl is the Lead Engineer for Material Integrity Solutions, Inc. and has over 7 years of experience in the design, analysis, and product development of mechanical and electromechanical systems as well as orthopedic biomechanics. His key strengths are in mechanism design, finite element modeling, stress analysis, kinematics analysis, material testing, and machining/fabrication processes. David received his Ph.D. in Mechanical Engineering from the University of California, Berkeley, with minor in Material Science. He has M.S.M.E. from UC, Berkeley and B.S.M.E. from UC, Davis. He has numerous technical publications.

Legal Matters:

A Checklist for Investigation of Facts Following an Electrical Contact Accident

by Cynthia M. Curric, Esq., Partner, Crisp, Page & Currin, L.L.P.

You are the electric utility's safety coordinator. You receive the following urgent call: A well repairman, Joe Adams, has just completed well repairs and has raised a forty-foot well pipe into the air to put it back into the well. The pipe has come into contact with your electric utility's 7,200-volt electric line. Electric current traveled from the line down the pipe, and Joe Adams has sustained severe electric burn injuries. He has been rushed by ambulance to the local hospital.

As the safety coordinator, questions fly through your mind. Was the electric line conspicuous? Was the line in compliance with height requirements of the National Electrical Safety Code? What actions should you take, as safety coordinator? Whom do you notify?

It is imperative in this urgent situation that evidence be gathered from the scene quickly and accurately. It is most important that the utility representative focus on the facts. The investigation of a contact case should focus on fact finding, and not on fault finding.

The electric utility needs someone on site immediately, before the scene or the evidence changes in any way.

We propose the following twelve (12)-point action checklist to ensure acquisition of all relevant data:

The Dozen Duties Checklist

1. Notify CEO and Safety Coordinator.
2. Notify general counsel.
3. Notify insurance company.
4. Have general counsel employ expert to gather data ASAP.
5. Notify OSHA and/or local law enforcement/fire departments, as required.
6. Take photos/video of contact site and lines, before repairs and then later after repairs.
7. Record specific and accurate measurements and take photos at each relevant point (point of contact; point of arc; height of line), all with a measuring tool in the photos.
8. Take photos of entire scene; take close-ups, distance shots, points of contact, and panoramic views, date each photo; provide description of photo and location/angle from which taken.
9. Draw a diagram to include as part of the incident report. Include line heights, lateral distances to objects and buildings, distances from contact point to all other points of reference. Sign and date the diagram.
10. Preserve evidence from scene (such as wires showing point of contact or arc).

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11. Have general counsel interview witnesses (tape record individual interviews; have tapes transcribed; preserve tapes).
12. Order copies of all information that is publicly available, such as reports by OSHA, local fire department, while all information is fresh on everyone's mind.

The electric utility should have an Incident Report form that is used regularly to gather all of the pertinent information for internal purposes. The form should state that the information is gathered to assist the corporation in undertaking subsequent remedial measures, which, if taken prior to the incident, would have made the incident less likely to occur. In addition the Incident Report form should state that it is prepared in anticipation of litigation, or for trial, concerning the incident.

Finally, the Incident Report form should state that it is a confidential communication from the corporation to the corporation's general counsel, seeking legal advice regarding the incident. Inclusion of this information on the Incident Report form will make it less likely that this material would be subject to discovery in a litigation setting. Corporate management should confer with its legal counsel in drafting such language.

The Incident Report form should list not only the date and time of the incident, but also the time the electric utility was notified of the incident. Other specifics to be gathered on the Incident Report form include: location; date the form was completed; identification of the individual preparing the form; name, address, and telephone number of the individual injured; a description of the extent of the injury; the location of medical treatment; the identity of electric utility employees or agents at the scene; identification of other witnesses; identification of law or other officials investigating; a statement of weather and geographical conditions, including terrain; system data including voltage, type and size conductor, and type pole structures; protective devices including type, location, rating, and whether the protective devices operated; a description of the incident; whether an outage occurred, and if so the time and the duration of the outage; code requirements for the line in question; identification of any product or equipment involved; description of any warning signs, and; the nature of any property damage.

In addition, the Incident Report form could request a listing of any factors, events, conditions or actions that may make similar incidents less likely to occur in the future. The Incident Report form could also request corrective action taken or recommended to prevent a similar incident.

Copies of the Incident Report form should be distributed only to specified top management and the company's general counsel.

The U.S. Department of Labor, Bureau of Labor Statistics, for work-related electrocutions and electric shocks for the year 1995. Construction trades led all other occupational groups affected by contacts with electric current. Electricians and their apprentices accounted for 20% of the electrocutions as well as 20% of the electric shocks. Other occupations that often result in electric related injuries include mechanics, farming jobs, construction laborers, and machine operators.

In addition, other examples of public contact cases include the following scenarios:

- Consumer raising radio or TV antenna into line
- Farm machinery contacting line (auger, cotton picker, or irrigation pipes)
- Machinery on a construction site contacts line (crane, boom or measuring rod)
- Consumer raising metal portable ladder into line
- Sailboat mast contacting overhead lines
- Painters/workmen contact line
- Cable company employees contact electric lines
- Roof contractor contacting line
- Car hitting pole causing downed line
- Firemen contact downed line

The company's safety coordinator should have, always ready, a tool kit chock-full of the equipment needed to investigate such an incident. The tool kit should include camera and extra film; video camera and extra video cassettes; tape measure; measuring rod; yard stick; ruler; and several copies of an Incident Report form.

Be prepared to perform each of the dozen duties on the checklist. □

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Cynthia M. Currin is an attorney in private practice in Raleigh, North Carolina in the law firm of Crisp, Page & Currin, L.L.P. She is the editor of the Currin Energy Page®, a monthly publication reporting electric legal issues (www.currinenergy.com). Ms. Currin earned her A.B. in 1977 and her J.D. in 1980 from University of North Carolina, where she was Phi Beta Kappa. She concentrates her practice in Electric Utility, Electric Cooperative and Corporate Law. She has served as counsel for electric utilities for over 23 years. She is President of the North Carolina Electric Membership Cooperative Counsel Association. She is a former member of the Board of Governors of the North Carolina Academy of Trial Lawyers (NCATL), a member of the NCATL Editorial Board, and past editor of NRECA's Legal Reporting Service. She is a certified arbitrator and mediator in the State of North Carolina.

Business Electric:

Is Reliability a Good Investment?

by Arthur J. O'Donnell, Independent Energy Journalist, The Energy Overseer

We have something of a consensus opinion that additional infrastructure investment is necessary to improve reliability. Exactly how much capital investment is needed remains open to debate. In its most recent estimation of investment to upgrade and maintain a power delivery system that meets the needs of the 21st century, the Electric Power Research Institute (EPRI) suggests at least $5.5 billion must be spent each year for the next 20 years—$110 billion in all.

Even a $200 billion investment could reap $700 billion in benefits, if transmission owners can be convinced to invest at that level. Other articles in this special issue address whether this is even likely.

But what about the other side of the buck? Does the need for reliability investment present an opportunity for profitable investments by individuals and institutions in the companies that make the hardware that would go into a modernized and robust electricity delivery system? If so, which are the companies most likely to capitalize on this highly anticipated market?

We know that the failure to provide reliable electric service can be hazardous to a company's fiscal health and its public perception. The prime example is First Energy (stock symbol: **FE**). The Ohio-based utility has borne much of the blame for allowing a somewhat routine tree-line contact event to get out of control and trigger a cascading outage affecting over 50 million people throughout the Northeast.

FE's share price was already on a downward trend in July, based on questions about its nuclear power operations. The stock-price slippage turned into a landslide immediately after officials began pointing fingers at the utility's operators and miscommunications with the Midwest Independent System Operator. Not only was the company hit with multiple class-action suits by attorneys purporting to represent shareholders, FE was vilified by one Democratic presidential aspirant, who called for outright revocation of the utility's license to sell power at wholesale and its local operating franchises.

From a high point of $39.42 per share at the start of July 2003, FE's stock price plummeted to $25.82/share on August 17, and has faced a long, hard climb back to the $39/share level. All along the trail, FE executives have been fighting the stigma of their utility being the trigger of the Great Eastern Blackout. Shareholders have stuck with the company, apparently believing that the utility is not completely to blame, despite the harsh spotlight.

In comparison, another major Ohio-based utility, American Electric Power (**AEP**), avoided much of the liability for the outage, as its controllers and systems automatically responded to limit outages within its territory. As a result, AEP executives not only earned some bragging rights when they testified to Congress about how they were able to keep the lights on for most customers, they also avoided a stock price hit. The usual crests and dips in price notwithstanding, AEP for the past nine months been on the upswing, reaching its 52-week high price of over $35/share in March before leveling out a bit in the past month.

While the public perception of an electric utility is tied very strongly to its reputation for reliability, an increase in spending for transmission systems is not likely to result in any particular boom in utility investor interest. A potential financial upside would be avoidance of possible penalties for failing to meet new reliability standards, if approved by Congress.

The Federal Energy Regulatory Commission might spur new infrastructure investment with incentives such as higher-than-average rates of return, but the net impact on a company's revenues will be minor. Transmission makes up only a small portion of the utility bill.

The bottom line: Additional reliability spending will be a pass-through expense for the transmission owners and utilities, beneficial mainly for adding new value to a largely depreciated asset base and avoiding rate disallowances or other penalties

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for reliability failures. Many believe that mandatory reliability standards, with enforcement teeth, will be the only way to bring investment up to the needed levels.

Where would the money go?

By any measure, $100 billion to $200 billion in additional spending would be a substantial increase to what is currently being budgeted for transmission system capital improvements. The Department of Energy has documented the steep and steady decline in transmission capital investment over the past 25 years. Transmission-related spending has fallen by over $100 million each year, dropping from a high of $5 billion annually in the late-1970s to a little over $2.5 billion per year in the most recent calculation.

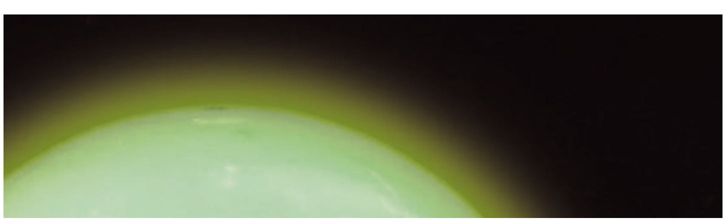
The makers of wire, steel towers, transformers and switchgear have all seen their production and sales figures languish during the past two decades. Worse still, an expected boom in orders from non-utility and merchant power producers collapsed with the wholesale market. Major manufacturers that were once the preeminent brand names of the industry have endured bankruptcy, disappeared, or been merged with others. Equipment facilities that until recently were considered "state of the art" have changed hands or been shuttered — sometimes both — as their owners shift production across borders.

But change is already in the works.

With an upsurge in overall economic activity in the first part of 2004, many industrial companies are reporting a welcome rise in confidence and factory utilization, says the National Electrical Manufacturers Association. Specific to the power equipment business, major manufacturers of large transformers are reporting a noticeable increase in orders, and dominant makers of wires used for high-voltage transmission cite an increase in utility purchases of bare wire for overhead transmission in 2003, reversing recent trends.

The mood of the industry is increasingly hopeful, with some analysts already seeing a 20 percent increase in transmission construction activity compared to last year. "It will go skyrocketing," says Pete Sholman of Allegheny Marketing. "The only question is when."

In EPRI's current forecast of needed investment, more than doubling the current rate of spending on delivery infrastructure is necessary just to keep pace with the growth in demand for electricity and to relieve the most serious system bottlenecks that have developed as a result of past growth. Even more needs to be invested to meet the increased demand for ultra-high power quality—that means everything from a "self-healing grid" to more efficient end-use technologies.



The big-ticket items for spending over the next 20 years are as follows:

High current/superconducting wires and cables	$30 billion
Reliability centered, predictive maintenance	$20 billion
Automation of transmission grids and substations	$10 billion
Power electronics: controllers, current limiters and breakers	$10 billion
Higher voltage lines and substations	$10 billion
Emergency restoration services	$10 billion

Numerous other categories — from energy storage systems to dynamic thermal monitoring devices — account for the rest of the EPRI reliability budget. The market for an individual category of products is quite large, for instance, in sensors/monitors and communication systems. According to EPRI, some 400,000 units costing an average $10,000 apiece would comprise a $4 billion market in the time frame envisioned.

There are several problems an individual or institution faces in trying to identify potential reliability investment plays. First of all, the industry sectors most likely to address the reliability need are incredibly fragmented and the vast majority of firms are not publicly traded corporations. In the world of power relay equipment and sensors, for example, such companies as Schweitzer Labs and S&C Electric may be poised for great things, if spending plans come even close to projections. However, as private companies, the resulting profits will not be reflected or distributed in any public marketplace.

Focusing on the few companies that sell stock to the public certainly narrows the field. Familiar names that have been part of the electric industry for a century remain leaders. A half-dozen multi-national firms—ABB, Ltd (**ABB**), Cooper Industries (**CBE**), Eaton (**ETN**), General Electric (**GE**), Schneider Electric (**SCHN-Berlin**) and Siemens AG (**SI**)—account for nearly half of the domestic market for electric power equipment. Many other companies, ranging from American Superconductor (**AMSC**) to SPX Corporation (**SPW**) and Hubbell, Inc.(**HUBb**), are eager to see increased spending for the niche markets they serve and power equipment they sell.

With few exceptions, the largest of these firms have worldwide markets for a multitude of products that go far beyond the electric power industry. Eaton (**ETN**), for instance, is the top seller of relays and industrial controls, with $7.2 billion in sales for 2002, and a stock price that hovers around the $60/share rang even after a 2/1 split earlier this year. In business since 1916, Eaton is best known in the utility business for its Cutler-Hammer brand of diagnostic devices. But the power division is only a small portion of Eaton's overall business, which lately has been on the upswing because of its automotive and fluid power segments. The same could be said for Emerson Electric (**EMR**), the world-wide conglomerate that straddles utility, industrial and consumer product lines.

Danaher Corporation (**DHR**) is positioned in the T&D field through its 1995 purchase of Joslyn Hi-Voltage, but that is a minor component of the overall business. Similarly, Germany-based Schneider Electric (**SCHN**) rises to near the top of the list for makers of electric transformers, by virtue of its Square D subsidiary, but its share of the U.S. utility and power transformers is miniscule. Hubbell, Inc. (**HUBb**) has a presence throughout the electrical products industry, and while its acquisitions of such well-known brands as A.B. Chance and Ohio Brass has bolstered its Hubbell Power Systems division, the corporation's fortunes rest on a broad platform of marine systems, automation and other industrial products.

"Finding the magic investment opportunity in electric system reliability may be elusive. At this point, this columnist would not offer any recommendations at all, except to identify those firms that are most likely to be competing for any additional dollars that are devoted to upgrading our deteriorating system."

Waukesha Electric Systems remains one of the few U.S. companies active in the depressed power transformer market, following its acquisition of Rockwell's transformer manufacturing operation in 1999. The company is just one part of SPX Corporation (**SPW**), whose fate in the stock market has been more recently influenced by a settlement of litigation with Microsoft. Sales of cooling equipment and telecommunications equipment to Asia is considered more of a bright spot than the domestic market for electric power transformers.

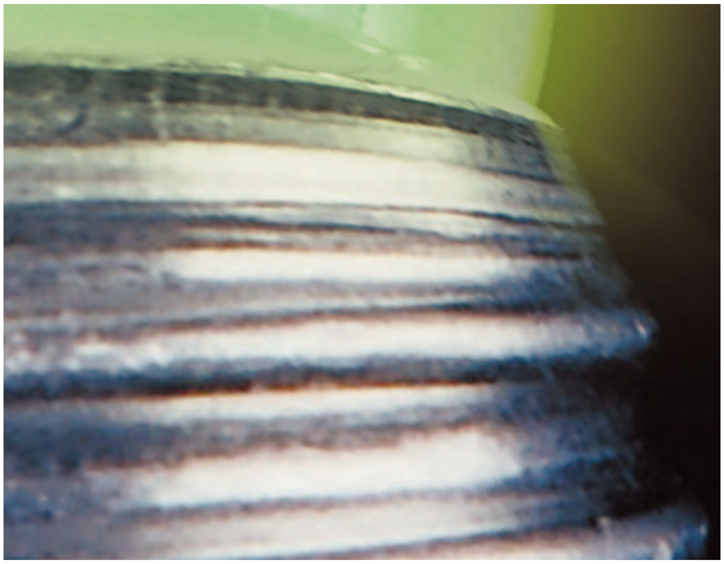
For the most part, these companies' stock prices will rise and fall based on factors other than transmission spending. Their fates are tied to overall industrial activity in the major markets of North America and Europe, and a finally stirring Asian economy.

For such diversified equipment and consulting companies as ABB, Ltd, (**ABB**), an increased investment in power electronics, broader use of flexible alternating current transmission (FACTS) and high-voltage direct current (HVDC) as seen by EPRI, might be a welcome source of revenues, especially after several very difficult years for the company. Still, it would be a small part of the company's $18 billion in world-wide sales last year, and as ABB executives review their strongest markets, selling electric motors and industrial robots in China represents significantly more potential than even a doubling of the U.S. market for power transformers.

So, finding the magic investment opportunity in electric system reliability may be elusive. At this point, this columnist would not offer any recommendations at all, except to identify those firms that are most likely to be competing for any additional dollars that are devoted to upgrading our deteriorating system. To do so, I've set up a "reliability investment portfolio" on my Yahoo account, meant to track more closely 14 of the companies I've named to see how they will fare as the debate over electric system reliability proceeds. Utilities FE and AEP are on the list as utility benchmarks, joined by a dozen firms that make or supply network-grade electric power equipment (see chart).

Company	**Ticker Symbol**	**Per Share Price Aug. 15, 2003**	**April 23, 2004**	**Change**
American Electric Power	NYSE: AEP	$27.42/share	30.77	+ 3.35
FirstEnergy	NYSE: FE	29.98	39.25	+ 9.27
ABB, LTD.	NYSE: ABB	4.69	6.09	+ 1.40
American Superconductor	Nasdaq: AMSC	13.20	14.35	+ 1.15
Composite Technology	OTC: CPTC.OB	0.60	0.91	+ 0.31
Cooper Industries	NYSE: CBE	47.48	57.99	+10.51
Danaher Corp.	NYSE: DHR	75.71	93.99	+18.28
Eaton	NYSE: ETN	89.25	60.95 *	+32.65 *
Emerson Electric	NYSE: EMR	52.51	62.07	+ 9.56
General Cable	NYSE: BCG	8.15	8.42	+ 0.27
General Electric	NYSE: GE	28.78	30.69	+ 2.91
Hubbell, Inc.	NYSE: HUBb	38.54	44.95	+ 6.41
Siemens AG	NYSE: SI	59.11	77.35	+18.24
SPX Corp.	NYSE: SPW	48.15	49.20	+ 1.05

** adjusted for 2:1 stock split February 24, 2004.*



Tomorrow's Technologies Today

Turning once again to EPRI's priority list for spending, one might detect a specific market opportunity for sellers of high-voltage power conductor and cable. There are a few public companies, including General Cable Corporation (**BGC**) and Alcan (**AL**), which along with privately held Southwire Corporation, currently have a lock on the market for "bare wire" conductor used for high-voltage lines. With new transmission construction at a near stand-still for a decade, their most promising markets have been to replace traditional aluminum core steel reinforced (ACSR) wire with alloys or aluminum core steel support (ACSS) cable at a higher cost for improved reliability.

After several years of depressed sales, these wire companies are finally reporting increased sales to utilities and in one instance, a return to nearly full production capacity at their factories. Offsetting the good news has been the recent run up in the cost of conductor metals, copper and aluminum — although many wires contracts have a metal-price adjustment as part of the deal.

Keys to profitability for these firms will be almost directly proportional to the amount of new transmission capacity that is added to the U.S. grid. Current projections see 7,500 miles of new high-voltage transmission on the planning boards throughout the nation. Compare that to only 350 miles of new transmission lines above 230-kV that were reported by utilities to the Energy Information Agency in 2002, and another 1,000 miles of lines restrung each year to improve carrying capacity.

Further down the road, domestic upstarts in the high-temperature superconductor (HTS) arena and other conductor technology, plus multinationalists Pirelli and Sumitomo, may be on the cusp of a boom in transmission conductor spending, if they can successfully bring their products to market.

Currently, the most viable niche in utility applications will be in underground cable installations through highly developed communities, where the expense of overhead wiring or community opposition militates against traditional overhead high-voltage configurations. Because of superior conductivity and less need for transformers, superconductive cable applications have a smaller local impact than traditional lines.

HTS and composite wire makers see the possibility of broader commercial application by the end of the decade, although they are initially targeting underground cable applications in very dense urban centers. One of the first long-length utility demonstrations will take place beginning in 2006 in East Garden City, Long Island.

Right now, such companies as American Superconductor (**AMSC**) and Composite Technology Corporation (**CPTC**), are rising and falling on investor expectations rather than proven financial results.

The task for these newer entrants will be to turn demonstration projects into commercial installations and help transform a traditional and moribund utility market into a high-tech arena, in line with EPRI's vision.

Just don't expect results overnight.

Disclaimer: Arthur O'Donnell is an independent energy journalist, not a stockbroker or investment analyst. O'Donnell owns no stock in any of the companies reviewed, and none of the above is intended as investment advice. □

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*As the founding editor of the **California Energy Markets** newsletter in San Francisco from 1989 through 2002, O'Donnell earned First Place honors from the National Press Club of Washington, D.C., in the category of "analytic reporting for newsletters" in the 2001 awards. He was honored as "Person of the Year" by the Power Association of Northern California in January 2003.*

In 1981-82 he was a Graduate Fellow in Business and Economics Reporting at the University of Washington.

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