



WELCOME TO THE GRID

On August 1, 2014 the National Electrical Safety Code (NESC) celebrated its 100th anniversary. For over 100 years now the NESC Committee has been working to provide a standard to keep electric workers and the general public safe from electrical hazard.

For the large majority of its existence the NESC has remained relatively unchanged. However, over the past few decades the code has undergone several changes as the industry faces broad change. As technology brings about revolutionary change the NESC will be faced with many new challenges in the power delivery industry. When the NESC first hit the scene there were no community solar, wind farms, fiber networks, or the concept of a "SMART Grid." As utilities are having to adapt, so too will the NESC.

A few of the proposed rule changes will address strength requirements for poles under 60 ft., photovoltaic panel pole attachments, and alignment of NESC's work rules with new Occupational Safety and Health Administration (OSHA) in particular arc flash requirements.

Protecting the safety of people and your interests are utmost to our design approach and project management teams. Let our team of trained professionals assist you in navigating the challenging times ahead. Best wishes and enjoy this edition.

Phil Carroll
Vice President



Joint Use Attachments

Getting More Complex and Challenging

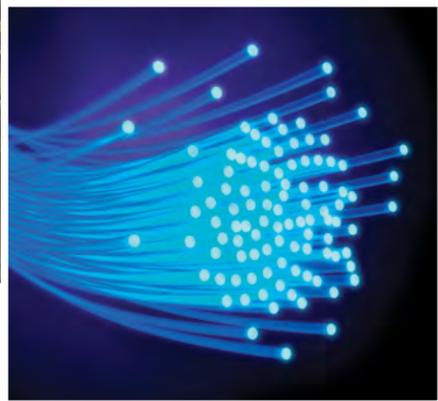
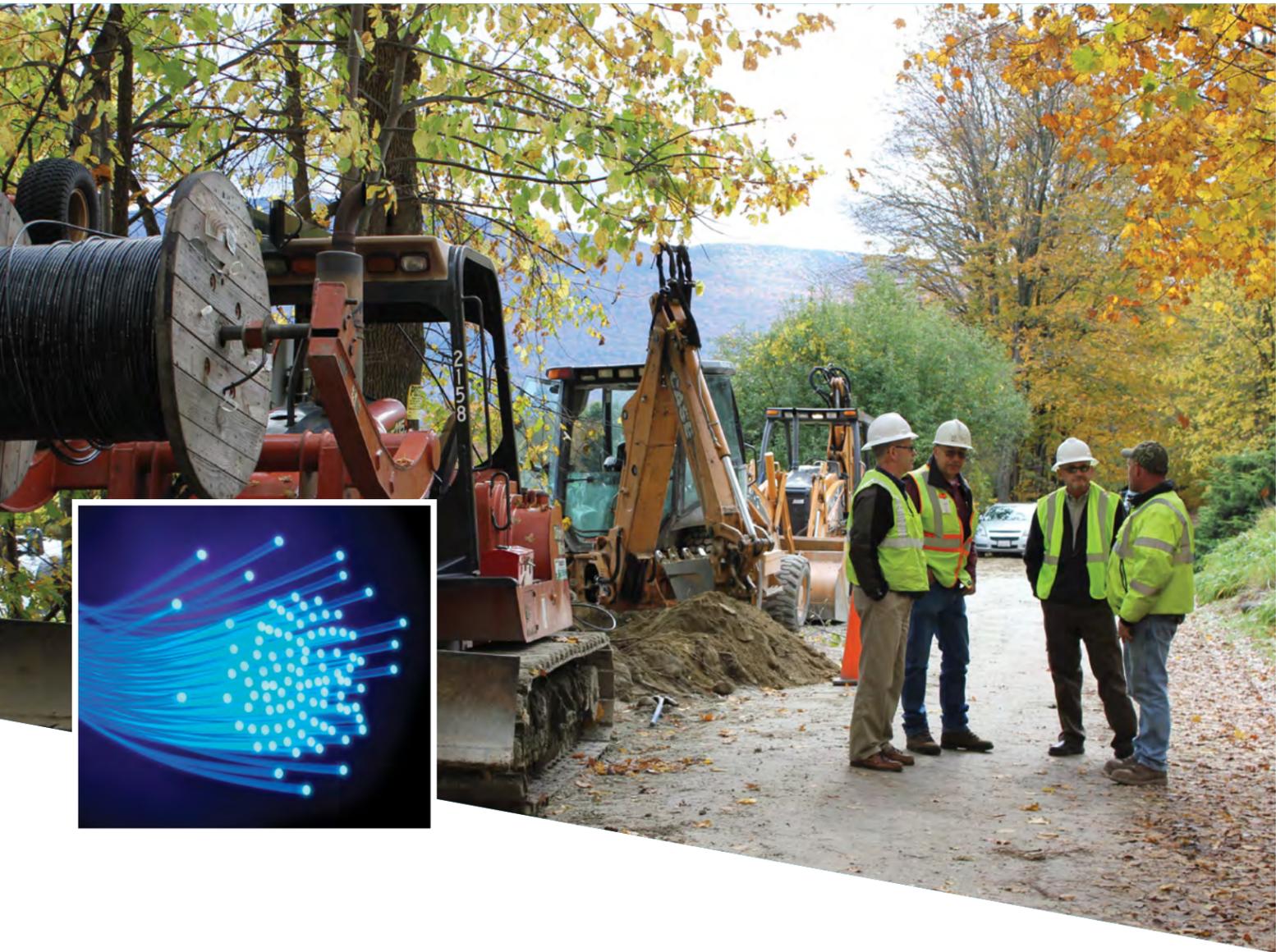
More and more these days, utilities are becoming increasingly aware of the potential issues, challenges and problems that can occur related to joint use activities (third-party pole attachments) that are not done properly. Many attachers would prefer to complete the engineering however, this is not in the best interest of the owner.

On paper, there are specific requirements, regulations, and

codes in place from the Federal Communications Commission (FCC), the National Electrical Safety Code (NESC), as well as state public utility commissions (PUCs) and public service commissions (PSCs).

On the operations side, there can be significant costs associated with direct damage to poles and wires, as well as indirect damage caused by damaged poles and power lines from excessive winds, ice storms, or other events. These costs can include direct repair costs, claims from third parties resulting from damage to critical utility infrastructure, as well as

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Fiber Network Experience

For many of our utility clients, our high speed fiber expertise has garnered greater interest. Our 60-plus years of telecom make us a sought-out leader for high speed fiber networking and broadband buildouts.

Our experience in communications includes design of over 1,000,000

miles of copper, coaxial, and fiber optic telecommunications cable, and a variety of network and switching installations. With our experience in both communications and energy, we are the perfect partner to meet with and discuss your strategic options around fiber optics.

Learn more about Finley's capabilities. View our Finley Overview at www.fecinc.com/resources/presentations

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legal costs related to who did not provide accurate data to complete accurate engineering.

Protecting Your Assets

The FCC stipulates that engineering must be performed at the cost of the requesting party (the company wanting to do the attaching) to determine compliance with the NESC. Sometimes, the utility sets this up, by providing the attachers with the names of approved vendors, as long as the attachers provide proof that due diligence has been done and that proper engineering has been performed to ensure compliance with the NESC.

A utility that needs this work done has some options. One is to do the engineering itself. Another is to hire a third-party engineering firm to do the work. A third is to provide a list of qualified third-party engineering firms to the proposed attacher, which then contracts with the engineering firm.

In all cases, it is the responsibility of the attacher to ultimately pay the engineering costs. If the utility does its own engineering, or hires its own third-party engineering firm, it bills the attacher. If the attacher hires the third-party engineering firm, the attacher pays the engineering firm directly. If the utility does the engineering itself and doesn't determine the time spent doing so, they may not pass their costs on to the joint attacher. The joint attacher may therefore receive free engineering services,

and of course if something is free the utility ends up fielding many more requests to see if attaching to a pole line makes economic sense.

If the utility selects a third-party engineering firm such as Finley Engineering to do the engineering analysis, Finley will tell the joint attacher where to attach, how to attach, etc. We use technology and instrumentation to assess the proper clearances. We then bill the utility, which can then bill back to the joint attacher.

Finley's focus is to ensure that values are accurate. We just make sure we comply with the NESC. We also make sure that the agreements are written for the benefit of the utility, not the joint attacher. This can save the utility a lot of money.

Finley Engineering offers a number of services related to asset management permitting, including: collecting field data required for analysis, providing structural evaluation for ground clearance, performing structural analysis utilizing PLS-POLE software, calculating vertical separation of cables and conductors, providing engineering remedies,

providing prints, populating work management systems, coordinating construction, performing post inspections, and closing out projects. Finley offers a complete turn-key solution so the utility can focus on running their core business and keep costs truly separated from other parties increasing their expenses.

Finley also offers National Electrical Safety Code (NESC) compliance audits, including: identifying NESC violations, designing recommendations, facilitating all utilities, providing construction drawings, project management, construction management, and conducting post-project inspections.

FERC Order No. 1000: IMPLICATIONS FOR ALL UTILITIES

On August 15, 2014, the U.S. Court of Appeals for the District of Columbia affirmed FERC's Order No. 1000 (issued July 2011), which is designed to build on Order No. 890 and reform FERC's electric transmission planning and cost allocation methods for public utility transmission providers.

In sum, Order 1000 is a move toward expanding transmission planning from regional to interregional planning, based on the idea that wider planning is better planning.

Order 1000 has potential implications for all utilities, large and small, even those that do not own, or plan to own, transmission assets.

General Requirements

Order 1000 establishes three requirements for transmission planning:

1. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890, and that produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.

3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

Order 1000 also establishes three requirements for transmission cost allocation:

1. Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purpose of cost allocation.
2. Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective.
3. Participant funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

ROFR Implications

Order 1000 also establishes reforms for non-incumbent developers. Under Order 1000, public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal (ROFR) for a transmission



facility selected in a regional transmission plan for purposes of cost allocation, subject to some limitations: 1) This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation. 2) This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers. 3) Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting or transmission facilities.

The rule also recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

That is, Order 1000 removes the federal ROFR for transmission

projects that are identified in a regional plan for the purposes of cost allocation. As a result, many transmission projects that have traditionally been assigned based on geographic location and service territory may not be open to competition. In sum, incumbent utilities will no longer maintain the federal ROFR to build, own and operate large-scale transmission projects that are located within their service territory. Removal of this ROFR could potentially change the way large transmission projects are identified and awarded.

According to Moody's Investor Services, Order 1000 is particularly important as a result of the removal of the ROFR from regional tariffs, where incumbent transmission providers had historically been given a preference on transmission projects in their existing territories. Still, though, Moody's believes that incumbents will be able to maintain an edge in bidding in their own territory as a result of long-held relationships with regulators, existing rights-of-way, proven operational track records, and knowledge of the network in their territory. In fact, according to Moody's, large transmission owners may be the ones that are best positioned to win new transmission projects put up for competitive bids.

Transmission-Only Entities

Another result of Order 1000 is that many utilities are actually creating transmission-only subsidiaries as a way to bid for new transmission projects. Many of these subsidiaries may enter new service territories by establishing partnerships or joint ventures with incumbents that are already established in those territories.

In addition, according to Michael A. Socha, P.E., Director of Business

Development, Energy Division, for Finley Engineering Company, some of these new entities may actually seek outright purchase of existing transmission assets from other utilities.

"Utilities used to be able to extend their transmission lines, and were the only ones who could," said Socha. "Order 1000 now says that, if other entities are able to build lines cheaper and also maintain those lines, these other entities can enter the market and compete with the utilities." In addition, if the utilities in their home territories are not interested in building new transmission lines, these other entities can also enter the market.

"We are starting to see new transmission-only companies pop up in the market," said Socha. "These entities are in business to build transmission lines and/or to purchase existing transmission lines." As a result of this trend, it is possible that some utilities may be approached by these new entities seeking to purchase their transmission assets, and/or to purchase right-of-way so they can build their own new transmission lines.

If a utility is interested in selling its transmission assets to one of these companies, it is very important that they secure the services of a qualified and independent third-party firm to be sure the utility receives the proper payment and to also help them determine all of the subsequent implications of the sale.

"For example, Finley can assist a utility in conducting an inventory of assets, as well as a valuation," said Socha. "Many utilities may undervalue the true worth of their assets, which is why a professional third-party valuation is so important." According to Socha,

utilities must define the actual point of ownership/sale when entering a substation (i.e. high side transformer bushings), along with other related assets (control house, high side relays, etc.).

Second, Finley can provide an assessment of what impact the sale of the utility's transmission assets will have on its system.

Third, if the utility does make the decision to sell, Finley can provide insight into how the utility should utilize the funds it receives on the sale of its transmission assets. Examples could include beefing up its existing distribution system, entering other markets (such as fiber to the home), and/or even lowering its retail rates to customers.

"Finally, some of these new entities may also approach utilities that don't even own any transmission, to see if they can purchase some right-of-way so they can build their own transmission," he said. Here, again, Finley can provide assistance in valuation and implications.

Finley Engineering has multiple locations to serve you. Our Energy Group is based out of Kansas City and Lamar, Missouri. For more information, visit www.fecinc.com.

STEP Program Back in the Forefront: SPARE TRANSFORMER EQUIPMENT PROGRAM

Renewed interest in a program launched by the Edison Electric Institute (EEI) in 2006, moved front and center in early 2013, in the wake of the now well-publicized sniper attack on PG&E's Metcalf Transmission Substation.

The program, called Spare Transformer Equipment Program (STEP) actually came into existence as a result of the 9/11 terrorist attacks. Given the long lead times required for manufacturers to build substation transformers (up to two years), the goal of STEP was, and continues to be, the opportunity for member utilities to purchase spare transmission transformers from other member utilities following a "triggering event," which is defined as an act of terrorism that destroys or disables one or more substations and results in the president of the U.S. declaring a state of emergency.

STEP is open to any investor-owned utility, government-owned utility, or rural electric cooperative in the U.S. and Canada that owns transformers.

While STEP is similar to mutual assistance programs, there is one important distinction: While utilities that are members of mutual assistance programs are free to volunteer or not volunteer to help other utilities following disasters, members of STEP are required to sell their spare transformers to fellow utilities that suffer triggering events. In addition, member utilities are required to own and maintain a specified number of spare transmission transformers.

The Federal Energy Regulatory Commission (FERC) is also on-board with the program. The sale of a substation transformer typically requires the approval of FERC, which can involve a lengthy process. However, given the nature of a triggering emergency event, FERC has given blanket authority approval to STEP-related sales.

Another feature of STEP is that utilities can volunteer (but are not obligated) to sell spare transformers to other members that experience normal failures or other emergencies that do not meet a triggering event definition.

The utilities participating in STEP manage the program through an equipment committee and an executive committee. EEI serves as the day-to-day program manager. The committees also arrange for and coordinate transportation of transformers to and from member utilities. Options include truck, rail and/or barge.

Currently, 54 utilities are members of STEP, and their service territories cover over 70 percent of the U.S. transmission grid.

In late 2014, EEI expanded the concept of STEP with another program – SpareConnect. SpareConnect is an on-line tool available to utilities that are members of STEP, allowing them to network and share other related critical spare equipment, including bushings, fans, and auxiliary components in times of need.

SpareConnect does not create or manage a central database of spare equipment. Rather, it provides decentralized access to points of contact at electric utilities so that, in the event of emergencies, members are able to connect quickly with each other to arrange for the purchase of necessary equipment.

SpareConnect actually formalizes what has already existed on an informal basis among utilities, which have had a history of sharing equipment with each other in response to various unexpected outages and other emergencies.



New DOE Distribution Transformer Efficiency Requirements Go Into Effect in 2016

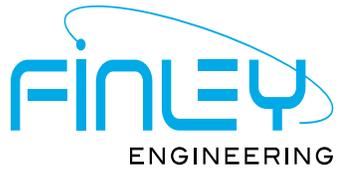
New increased efficiency requirements for transformers will go into effect in 2016, according to the U.S. Department of Energy (DOE). The DOE estimates that the new standards will save up to \$12.9 billion in total costs to consumers, and 3.63 quadrillion BTUs of energy for equipment sold over the 30-year period between 2016 and 2045.

DOE has regulated the energy efficiency level of low-voltage dry-type distribution transformers since 2007, and liquid-immersed and medium-voltage dry-type distribution transformers since 2010.

The DOE estimates that the new amended standards will further decrease electrical losses by about 18 percent for low-voltage dry-type transformers, 8 percent for liquid-immersed transformers, and 13 percent for medium-voltage dry-type transformers.

To view the accompanying charts, download our white paper here:
www.fecinc.com/resources/DOE





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THE GRID

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