Generation Interconnection Standards and Procedures

Engineering Assumptions for Generation Interconnection Studies

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I. Executive Summary

The Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice of Proposed Rulemaking ("NOPR") on April 24, 2002 on the Standardization of Generation Interconnection Agreements and Procedures. While FERC's proposed pro forma interconnection agreement and procedures hold out great promise for streamlining the process by which new generators obtain interconnection arrangements, the Commission's proposals lack precision in several important respects. Experience shows that this imprecision, if not addressed early and comprehensively, may be exploited by transmission owners so as to favor their transmission function and their marketing and generation affiliates.

Prominent among these imprecise features is the failure of the NOPR and the related pro forma interconnection agreement and interconnection procedures to devise objective and specific engineering assumptions for interconnection studies. All too often, interconnection studies have been manipulated to erect roadblocks in the path of new generation. This paper suggests a more specific, objective, and comprehensive approach. Hopefully, this approach will bring some order and equity to an interconnection process that is now rife with inconsistencies with respect to reliability criteria, modeling of generation re-dispatch, and design of the required transmission system reinforcements.

II. Introduction

In the wake of recent industry events, FERC's NOPR on the Standardization of Generation Interconnection Agreements and Procedures is being examined closely. In general, generation developers support unified interconnection standards. However, industry parties that now exploit the diversity and inconsistency of existing practices and standards are inclined to favor the continuation of the status quo.

Many hope that creating industry-wide standards and practices will resolve – or at least mitigate - problems that exist today for generators attempting to interconnect with the electrical transmission system. The belief is widespread that drastic action is called for. With a few exceptions, newly interconnecting generators believe that they are paying for transmission system improvements unrelated to the burden imposed by their interconnection applications. This obligation is being forced upon them as a pre-condition to receiving permission to interconnect. Generators are being saddled with costs to upgrade the transmission system, ostensibly so that the grid can maintain reliability standards after the addition of each new generator. However, in some instances the existing transmission system cannot achieve these same reliability standards in its present configuration. Generators also believe that certain transmission providers are using generation interconnection studies to provide advantages for the transmission providers themselves, irrespective of whether the transmission providers are generation owners.[1]

Although implementation of the proposed pro forma interconnection agreement and procedures will greatly facilitate and expedite the consummation of interconnection arrangements, the Commission's proposals remain imprecise in several important areas. These imprecise features are likely to be interpreted and applied in inconsistent ways by individual transmission providers. Unless changed, these features may continue to be exploited so as to favor transmission owners, generation affiliates of transmission owners and possibly other favored generators.[2] The imprecision arises mostly with respect to the interconnection study assumptions that transmission providers are allowed to make with respect to:

i. Applying transmission system reliability criteria in analyses of contingencies,

ii. Modeling of generation dispatch (and re-dispatch necessitated when modeling the addition of new generation), and

[1] Owners have an incentive to shift network upgrade costs to generators, even when those upgrades are not caused by the generator, particularly if the transmission owner is between rate cases or has a rate freeze in effect. The Authors of this paper have encountered numerous instances in which an applicant for a new interconnection is forced to pay for eliminating overloading that existed before the applicant interconnected.

[2] For example, by use of "inside" information with respect to needed upgrades, transmission providers can steer favored developers to sites that require few or no upgrades to accommodate new generation. On Long Island, New York, Keyspan sold its transmission assets to the Long Island Power Authority but retained the generation assets of its predecessor, the Long Island Lighting Company. Keyspan identified and secured several favored slots in the LIPA generation queue. A transmission provider or owner can also drive up the interconnection cost of a new generator, thereby favoring its affiliated generation. For example, by making self-serving assumptions, transmission providers can shift an unduly large portion of the total cost of upgrades needed by a transmission system to new generators.

iii. Designing network upgrades required for the relief of constraints.

This article addresses how such manipulation can be accomplished, and whether FERC's proposed generation interconnection standards and practices can prevent such manipulation.

III. Historic Generation System Planning

In a vertically integrated utility, power system planning historically involved three main steps:

i. Load Forecasting,
ii. Generation Planning, and
iii. Transmission Planning

At the risk of oversimplifying what can be a very complex process, load forecasting was usually based on the historic trend of the load growth, and the forecast was weather normalized.

Generation planning provided an answer to the questions of when- and how much- new generation should be placed in service in order to provide a reliable supply for the growing load under a least-cost criterion. The most frequently used generation reliability standards were Reserve Margin ("RM")[3] and loss of load probability ("LOLP").[4] Although there were many variations on the acceptable standard of reliability, it was widely accepted that a reserve margin of 15%-25% and/or an LOLP of "one day in ten years" would provide sufficiently reliable supply. Some studies[5] show that a Reserve Margin required to meet a LOLP of 1-day in 10 years is approximately 25 to 30%. Therefore, it is alarming that FERC's NOPR on Standard Market Design proposes a

[3] Reserve Margin: The difference between the total available generating system capacity and the annual peak system load, divided by the peak system load; i.e., it is the excess of installed generating capacity over annual peak load expressed as a fraction (or in percentage) of annual peak load.
"Expansion Planning for Electrical Generating Systems-Guidebook", IAEA, Vienna, 1984, page 244.

[4] LOLP: A reliability index that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. More specifically, it is defined as the number of days per year or hours per year when available generating capacity is expected to be insufficient to serve all the daily or hourly loads. "Expansion Planning for Electrical Generating Systems-Guidebook", IAEA, Vienna, 1984, page 245.

[5] PUC of Wisconsin, Docket No. 05-CE-113, Final Environmental Impact Statement on Arrowhead-Weston Electric Transmission line, October 2000, page 31.

minimum Reserve Margin of 12%,[6] leaving it to the Regional State Advisory Committees to revise this number higher voluntarily.[7]

The next step was the transmission system planning process. That process explored the various alternatives for transmission system development and sought to identify the least-cost proposal that would accommodate the reliable transfer of generation output to load. Transmission planning used a general reliability standard of N-1, or "N minus one",[8] when developing alternatives for the future use of the transmission system. Under the N-1 standard, the loss of a single facility should not result in the overloading of other equipment or violation of voltage limits, particularly during peak demand periods.

Continuous supply depended on the availability of the generation supply as well as the transmission system, and some LOLP methods simulated the effect of transmission limits and transmission outages upon bulk power reliability. Nonetheless, it was common in performing LOLP studies for planners to focus on generator outages and to assume that all generation could reach all load.

Inter-regional planning groups (such as regional reliability councils) determined the capabilities of existing and planned transmission systems to be used for inter-regional transfers and often recommended that additional facilities be added to facilitate transfers needed to provide reliability and power supply economics. These steps of integrated resource planning were performed in several iterations in order to determine the least (total) cost alternative that complied with both generation and transmission reliability standards.

However, this traditional method of integrated resource planning is rarely followed in the new electric regime. Because vertically integrated utilities are fewer in number and because their generation is often subject to competition from independent power producers, the generation versus transmission trade-offs are not systematically addressed. In addition, vertically integrated utilities no longer control the amount and timing of competitive generation additions (except possibly through their administration of new generator interconnections under the pro forma open access transmission tariff or "OATT"). More and more, the generation element of the bulk power planning function is

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[6] FERC NOPR on Standard Market Design, Docket No. RM01-12-000, July 31, 2002, page 266.

[7] Of course, it would not be productive for a region to mandate a high reserve margin if surrounding regions opt for a low standard. When cascading failures occur, they do not exempt sub regions with high reserves. All the interconnected systems would cascade into darkness together, irrespective of whether one or more of the sub regions adhered to a stiffer standard for installed reserves.

[8] Some utilities define their own more stringent standards.

carried out by Independent Power Producers ("IPPs") while the Regional Transmission Organization ("RTO") is seen as the entity that will carry out the transmission planning function.

IV. Current Generation Interconnection Procedure

Today, as a result of the restructuring of the electric power industry, generation and transmission systems each tend to be owned or controlled by separate, unaffiliated entities[9]. Generation development companies make their own decisions on investment in new generation projects based on their views of the market, and seek to develop generation on sites close to load pockets, gas pipelines and transmission lines, geothermal steam sources or locations with high winds. Participants in many deregulated markets have taken the position that there is no longer a need for a central planner to answer questions on when and how much generation should be constructed to insure that the reserve margin is acceptable or that LOLP equals 1 day in 10 years. The operative assumption is that prices will increase as reserves decline, spurring developers to respond and to restore adequate levels of generating capacity. The spate of California and Midwest prices spikes and curtailments vividly demonstrated the flaws in this simplistic notion. Clearly, some threshold level of installed reserves is required.

IV. 1 Position in the Generation Interconnection Queue

Under present generation interconnection procedures (that differ somewhat in various parts of the country), it is the general practice for a generation developer to apply to the ISO and /or transmission owner to obtain a position in the generation interconnection queue. Just a quick examination of the ISOs' and utilities' recent generation queues[10] suggests that all generation additions applied for, if constructed, will provide reserve margins and LOLP far beyond that which was considered adequate in past years. Some regions expected that their reserve margin would grow to over 30% within a few years. If all planned generation had been developed, it would have created an excess of power, which is a precondition for competition. However, the 2002 meltdown of the generating sector has now created the reverse concern.

[9] There are many remaining examples in which generation and transmission is owned by a single entity. FERC continually seeks to restrain the abuse of market power inherent in that arrangement, but the weakness of the independent power sector has sapped enthusiasm for this approach and has sidelined some of its principal proponents, most notably Enron and Dynegy.

[10] However, there are still publicly unavailable generation interconnection queues. An example is the Southern California Edison generation interconnection queue, a queue that is hidden both from the developers of new generation and from the public.

In general, a generator's position in the queue ensures that the project developer will not be responsible for any transmission system reinforcements caused by the interconnection of a generator placed behind it in the queue. Nevertheless, each generator may be required to share the cost for transmission system upgrades with generators that hold positions ahead of it in the queue. There are variations on this general theme. Under the sophisticated, probabilistic approach followed by the PJM Interconnection, L.L.C ("PJM ISO"), a transmission upgrade that may be required to connect a developer holding a position early in the queue may actually be eliminated if a later generator is interconnected. In such cases, the generator with an early position in the queue may be absolved of paying for an upgrade specific to its project and instead be required by PJM to contribute to the cost of a separate upgrade required for a developer with a later queue position. But there are obvious limits to the realization of this PJM ideal in that, eventually, piecemeal upgrades must often be constructed in order to connect needed generation. Otherwise, needed generation might not be connected in time to meet growth in peak demands.

IV. 2 Generation Interconnection Studies

Transmission system upgrades are determined through several studies that differ in scope and details. However, in the determination of necessary upgrades, the perfect can become the enemy of the good. That is, the pursuit of the perfect combination of transmission upgrades can delay interconnection of generators and bring on blackouts.

The common studies for most regions are:

i. Feasibility Study
ii. System Impact Study and
iii. Facility Study

The completed application for a specific interconnection that places the applicant in the queue is generally followed by a Feasibility Study.[11] The Feasibility Study provides preliminary information on the required transmission system upgrades and associated costs, based on a steady state load flow and short circuit analysis. An application typically includes the requirement for a payment of $10,000 to $25,000, which should cover the cost of the Feasibility Study.[12] If a developer decides to continue the process of

[11] In the California ISO, the denomination of studies is reversed. The feasibility study includes detailed design of facilities and is conducted after the impact study and the facility study.

[12] Some ISOs and utilities perform feasibility studies twice a year for all the candidates in the same queue. This means that having 50 applicants in the same queue can provide additional revenue of $1,000,000 to $2,000,000 per year only for the performance of the feasibility studies.

interconnection, the next step is an Impact Study that determines the transmission system reinforcements needed through analyses based on the steady-state load flows, short-circuit studies, and stability analyses. These types of studies usually require a payment of approximately $50,000-$100,000. Finally, if the developer desires to continue pursuing an interconnection, the Facility Study provides details on required upgrades and a more accurate cost estimate for necessary equipment additions. This study requires a separate payment.

V. Generation Interconnection Procedure as Proposed in the NOPR

The Generation Interconnection NOPR requires that the interconnection studies to be performed in order to identify direct interconnection facilities and network upgrades consist of short circuit/fault duty, steady state and stability analyses, similar to those required under existing practices.[13] Those studies are conducted for two categories of generation interconnection:

i. Energy Resource, and
ii. Network Resource.

Unfortunately, these underlying analyses are often not provided to the applicant, which prevents the applicant from identifying which type of resource its generation is best suited to become.[14]

V.1 Studies Required for Energy Resources

The NOPR defines the required studies for an Energy Resource as follows:

> *The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct interconnection facilities required and the Network Upgrades necessary to address short circuit issues associated with the interconnection facilities. The*

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[13] Interconnection Agreement, Article 4, page 11.

[14] It is beneficial for those generators contemplating making an interconnection request to be able to access the modeling data used by the transmission provider, in order for the generator to run sensitivity analyses on its planned unit, its size, and its location. Access to this data would be a benefit for both provider and generator, so long as the transmission provider no longer has the opportunity to manipulate the data to produce results that favor the transmission provider in some way. A vertically integrated utility will desire to use its generation first to serve load (ahead of using a competitor's generation), in spite of the fact that new merchant generators coming on-line tend to have lower costs, higher efficiencies, higher availabilities and lower environmental impacts than do existing generation. In this case, the provider has an incentive to keep its modeling data private so that it can manipulate the system to produce a result more favorable to the provider's other interests.

> *stability and steady state studies would identify necessary upgrades to allow full output of the proposed Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Facility without requiring additional Network Upgrades.*
> (FERC NOPR on Generation Interconnection, Section 4.1.1.2 of Interconnection Agreement, page 11)

For energy-only resources, this provision seems to escalate the rigor of the required studies, but for a very good purpose. Currently, although a steady state load flow analysis is ordinarily required, the steady state load flow was really superfluous because such resources had no rights to deliver energy except on a non-firm basis.[15] As a result, even though some portion of an energy-only resource might have qualified as a Network Resource at no incremental cost, or even though qualifying a new generator as a Network Resource for 100% of its rated output might have been achievable at a nominal incremental cost, the developer of an energy-only resource would not have been able to ascertain those facts from its impact study. Now, the impact study will provide information on both of those issues and enhance the likelihood that each new generator will become a Network Resource – at least in part.

For energy-only resources, the NOPR makes no change with respect to short circuit studies and fault duty analyses. In the past, such tasks were required to be performed (and must continue to be performed under the NOPR standard) for energy-only resources in order to identify the specific interconnection facilities needed in order to maintain stability and to isolate faults. This is intuitively correct. In other words, a new generator has to demonstrate that just by virtue of interconnecting - but producing no net output - it would not put the transmission system in danger of instability and that it would not cause fault currents (during short circuits) that exceed the capability of protective devices to interrupt power flows and to isolate the faulted portion of the system.

As noted, the NOPR requires that load flow and stability analyses be conducted for an Energy Resource in order to identify (1) Network Upgrades that would allow full output for the Energy Resource to be delivered and (2) the maximum allowed output of the Facility that would qualify as a Network Resource, without requiring additional Network Upgrades, at the time the study is performed. This is very valuable information that can be used by the developer of new generation to decide whether, and how much of, its facility should be qualified as a Network Resource.[16]

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[15] This is still the case with Energy Resources under the NOPR.

[16] If the new generator initially does not ask to be considered a Network Resource and then later opts for that status, that generator may step into the shoes of another new generator that is seeking that status. This may change the obligation of new generators with later slots in the queue to pay for upgrades.

V.2 Studies Required for Network Resources

For Network Resources, the NOPR attempts to define assumptions for the studies more directly, but as is the case with Energy Resources, specification of the assumptions remains too general:

> *The interconnection study for NR Interconnection Service shall assure that the Generator's Facility meets the requirements for ER Interconnection Service and as a general matter, that such Facility interconnection is also studied with the Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generator Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the Transmission Provider's Transmission System, consistent with the Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are [is] displaced by the output of the Generator's Facility.*
> ((FERC NOPR on Generation Interconnection, Section 4.1.2.2 of Interconnection Agreement, page 12)

This excerpt from the proposed IA requires that the generation interconnection for a Network Resource be studied:

- At the time of the Transmission Provider's peak load,
- Under a variety of severely stressed conditions,
- Consistent with the Transmission Provider's reliability criteria, and
- Under the assumption that a portion of existing generators' output is displaced by the output of the proposed generator.

The problem is that these assumptions can be interpreted (and now are interpreted) in vastly different ways by different entities.

V.2.1 Transmission System Reliability Criteria

Merely incorporating "the Transmission Provider's reliability criteria and procedures" will not ensure evenhanded treatment or lessen discrimination against new generators. Transmission providers/owners often employ their own unique reliability criteria and these criteria can be more stringent than those employed by the North American Reliability Council ("NERC") and by the relevant regional reliability council. Furthermore, those more stringent criteria differ from one provider to another even within a single regional council.

It is well known that regions use differing planning standards with the result that the reliability and adequacy of transmission systems differ from region to region. Some utilities that in the past used lax criteria in planning for local areas have turned over - or will turn over - deficient transmission systems to RTOs and ISOs. In these situations, new generators are sometimes called upon to remedy and pay for deficiencies in the transmission system that pre-dated their request for interconnection - deficiencies that they did not cause. Therefore, it is necessary that interconnection studies be performed using a base case that simulates the transmission system that existed prior to the proposed generator addition. This approach should ensure that the generator is being made responsible only for incremental criteria violations and not for pre-existing ones.

For this and other reasons, newly interconnecting generators are often placed at a disadvantage vis-à-vis pre-existing generators. Pre-existing generation is often owned by the transmission provider or has been sold by the transmission provider to an affiliate or to a favored buyer. Pre-existing generation has often been granted a grandfathered right to firm access to the grid in spite of the fact that providing that access violates reliability criteria. Accordingly, the NOPR should be amended to make it clear that the transmission provider is required to pay for all network upgrades needed to bring its transmission system into compliance with the relevant reliability criteria before testing for the effects of new generation. This may mean that the transmission provider must pay for upgrade costs that are now being shifted to newly interconnecting generators (or loads). It may also mean that the transmission provider will go back to grandfathered generators (or loads) for contributions to needed upgrades to the extent that interconnection agreements and tariffs enable transmission providers to do so.[17]

V.2.2 Severely Stressed Conditions

The NOPR proposes that network resources should be studied "under a variety of severely stressed conditions". This proposal may create more disadvantages for new generation developers. Transmission systems are usually not planned based on severely

[17] The Authors are aware of interconnection agreements that enable the transmission owners to take a "second bite" from the interconnecting generator, forcing the generator to pay for upgrades long after it commences service. This is sometimes justified because the timing and amount of future generation additions – even when they are permitted - are not always certain and the transmission provider wants to protect itself as a murky situation becomes clearer. This has turned out to be a particular problem with respect to high-voltage facilities that have been denominated as "distribution" as a result of "refunctionalization" under Order No. 888. Power flows related to station service to the generator are retail sales that are governed by State law whereas outbound deliveries of generation are governed by the relevant OATT.

stressed conditions. Severely stressed conditions are used primarily to assess short-term future operating conditions and to determine procedures that must be employed in order to avoid or mitigate their consequences. Moreover, testing for severely stressed conditions would allow each transmission provider to establish its own set of "severely stressed conditions" with the result that transmission providers could insist upon vastly differing network upgrades in similar circumstances.

Some language much more definitive than "severely stressed conditions" should be used to define the criteria for testing a transmission system with a new generator addition. It would be useful if the final rule clearly defined transmission reliability criteria that should be applied in the generation interconnection studies of each transmission provider. Those criteria should be consistent with NERC planning standards. As a starting point, single element contingency outages in addition to any outage associated with line or transformer maintenance that is already scheduled should be applied in the interconnection studies.

V.2.3 Modeling of the Generation Displacement

One recurring problem in interconnection studies – the lack of uniform, objective criteria for modeling the displacement of other generation when adding the new one - has not been addressed or resolved by the NOPR. In any interconnection study,[18] the output of some combination of existing generators must be displaced when modeling the addition of new generation. That is, the sum of (a) load, (b) losses and (c) net exports on one side of the equation must be in balance with the summation of (d) generation and (e) net imports on the other side of the equation - in any load flow simulation. So, when the output of a new generator is added to the simulation, one must back down the output of some combination of previously dispatched generation. There seems to be no objective or uniform criteria for specifying this assumption despite the fact that such an assumption (1) can substantially alter the overloads ostensibly caused by a new generator and, (2) can greatly effect the magnitude and cost of needed upgrades. Indeed, in the Authors'

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[18] Each of these studies uses the same input database commonly known as the load flow base case. The load flow base case contains data defining the load connected to the substations, generators, and attributes of the transmission system for the entire U.S.A. power system. However, those regions or areas that are under particular ISO or transmission owner operating responsibility are modeled in detail, while the outside systems are less detailed or "equivalentized". Currently, transmission providers use the NERC database to create the load flow base cases that model their system conditions at peak and non-peak periods for varying years in the future. Since the September 11th events, access to load flow cases and utility transmission system maps has been restricted by FERC, although previously this information was available to the public through the FERC Form 715. PJM, however, posts its base line load flow cases after completing the studies for a particular queue.

experience, the generation re-dispatch assumption is often made by the transmission planner in ways that are blatantly self-serving and subjective.

In the command-and-control regulated systems of the past (in which the fuel, efficiency and operating costs of each generator was a matter of public information), one could make educated guesses about what generation would be displaced first at any given load level. However, such cost and efficiency information is no longer publicly available with respect to many generating resources. In many circumstances, it is difficult to make even an educated guess about what generation would be displaced. Another impediment to making an educated guess is the fact that the dispatch of generation in a market-based bidding system is based on bids and not necessarily based on marginal costs.[19] In summary, one is no longer able to make educated guesses about what pre-existing generation will be re-dispatched in any particular scenario.

This lack of transparency has led transmission analysts to take a variety of approaches to modeling the redispatch of generation. In current practice, the approaches vary from shutting down particular generators - sometimes located at the same substation to which the new generator will be interconnected (ISO NE) - to reducing proportionally the total generation output inside the region to equal the output of the proposed generation (PJM), to increasing the total load to accommodate an increase in generation (ERCOT).

The NOPR does not provide any direction as to which approach should be used for modeling generation displacement. In addition, modeling is complicated by the NOPR requirement that all existing generation and all new generators in the queue ahead of the new generator being analyzed should be modeled in the base case:

> *The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no queue position but have executed an Interconnection and Operating Agreement or requested that an unexecuted Interconnection and Operating Agreement be filed with FERC.*
> (NOPR, Standard Generator Interconnection Procedure, Section 6.2, Page 13)

A literal application of the NOPR approach may result in the modeling of thousands of MW of generation in excess of the peak load on the transmission system. A

[19] These data are no longer a matter of public record.

transmission analyst can significantly alter the amount and cost of network upgrades required in connection with a new generator depending upon which of these assumptions he elects to make. Unless the Commission specifies which of the great variety of displacement approaches available to the analyst must be applied, the analyst will have the latitude to manipulate a situation. That is, merely by changing assumptions, the analyst can convert a situation in which a single new generator should be required to make no transmission upgrades into a situation in which the generator is required to make very extensive transmission additions.

It seems reasonable to suggest that FERC incorporate the PJM proportional reduction displacement approach.[20] Historically, this approach has resulted in moderate requirements for transmission upgrades and also has not jeopardized the reliability of the PJM transmission system.

V.2.4 Design of Network Upgrades

The results of interconnection studies show the transmission system reinforcements that are ostensibly required to accommodate the new generator interconnection. In the Authors' experience, transmission owners and providers tend to specify the addition of a new transmission line as the upgrade necessary to relieve constraints instead of examining other, less costly and less-intrusive options. To lessen the tendency of transmission owners to take a "brute force" approach, the final rule should require a design of the reinforcement that is identical to the approach that utilities and transmission providers apply in their own transmission system planning processes. Under that approach, those who perform the generation interconnection studies would be required to explore all options on the existing system such as new operating procedures, replacement of the limiting elements (e.g., re-conductoring existing circuits, increasing clearances between the line and ground on line segments that are limited by line sag or replacement of measuring equipment), bundling line conductors, reconfiguration of the grid, or any other intervention that does not require a new transmission line.

If the transmission provider is allowed to employ low-cost operating procedures to remedy criteria violations (overloads, voltage excursions and instability) as an alternative to making network upgrades, then new generators should also be permitted to employ

[20] Proportional displacement is only one feature of the very sophisticated, probabilistic approach to the problem of defining needed upgrades that is employed by PJM. The PJM approach – despite its analytical rigor – has led to relatively reasonable requirements for Network Upgrades as compared to those being specified under procedures administered by individual transmission owners, ISOs and other RTOs.

operating procedures to alleviate criteria violations identified in their system impact studies.[21] Such an approach would foster more evenhanded treatment of new generators. This can cause substantial effects (time delays) in capacity - short regions in that a new generator may become subject to what can be very onerous state certification requirements and processes once a massive upgrade has been designated.

In addition, there are a variety of new technologies that should be implemented to increase the capability of the national existing transmission system, such as the implementation of dynamic thermal ratings that vary with wind velocity, ambient temperature, and other weather related parameters, and new type of conductors. Applications of those technologies can substantially increase the capability of existing lines.

VI. Conclusions

The roadblocks identified above will only slow down the development of needed generation. Because new generation tends to reflect technological advances, it produces power at a lower cost than does existing generation and reduces environmental impacts. More specifically, emissions of pollutants from modern generation are lower per kWh of production than those from existing generators. Existing transmission constraints and the imposition of network upgrades will effectively reduce the incentive of market participants to build the new generation that is necessary to the continued reliability of the electric system.

In spite of the best efforts of the industry and an impressive feat of Commission rulemaking, the Generation Interconnection NOPR was not able to remove all incentives of transmission owners to manipulate the studies required for interconnection. It is therefore necessary to establish national generation interconnection standards with clear definitions of the study assumptions - on reliability criteria, generation displacement, and design of transmission system reinforcements - in order to prevent such manipulation.

[21] The Commission's consideration of self-funding of upgrade projects is particularly vulnerable to the disparity between the low per-unit cost associated with some upgrades and the high per-unit costs of upgrades typically required of applicants of newly interconnecting generators and loads. A for-profit transmission provider (such as an independent transmission company) is in a position to identify all the low-cost upgrades before other applicants can do so. A transmission provider is uniquely situated to identify low-cost upgrade opportunities because of institutional knowledge of the transmission system and because it has early access to the stream of applications for interconnections and the results of impact studies and facility studies. Armed with this "inside information", the transmission provider can seize the economic benefits of those low-cost upgrades for itself.

Another major deterrent to manipulative behavior is the establishment of truly independent RTOs that retain control over transmission system planning, that do not delegate crucial studies and other functions (rating of lines) to transmission owners, that have no profit incentive to exploit inside knowledge of the transmission upgrade process and that have no affiliation with the generation owners. These impartial RTOs should have little or no incentive to manipulate study results or to allocate costs on an inequitable basis.

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