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OCTOBER 2014 APPA LEGAL SEMINAR

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CAPACITY MARKETS AND RESOURCE ADEQUACY

APPA PRE-CONFERENCE WORKSHOP

OCTOBER 19, 2014

ALTERNATIVE RESOURCE ADEQUACY MECHANISMS

AND

WHERE CAPACITY MARKETS GO FROM HERE

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I. RESOURCE ADEQUACY WITHOUT MANDATORY MARKETS

Given the problems that mandatory, centralized capacity markets have encountered, it is not surprising that some regions of the country, even those with centralized energy markets, have declined to make the leap of faith and adopt them. Organized markets or not, all regions must ensure that they have adequate resources to serve growing demands. Other than mandatory centralized markets, how do entities solve the resource adequacy problem?

We should not, of course, overlook the traditional utility model. States that have not made the transition to retail access and auction-style markets still rely on traditional Integrated Resource Planning ("IRP"), where utility planners determine the most cost-effective set of resources necessary to meet a variety of goals — economic rates, environmental objectives, fuel diversity, reliability, avoidance of volatility — under the supervision of state regulators. In many ways, it has proven difficult to design market metrics that deliver all of the same values.

However, for those states that have moved away from the traditional utility model and dispensed with the obligation to serve, additional measures are needed to assure adequate resources for short-term markets. The California Independent System Operator Corporation ("CAISO") and the Mid-Continent Independent System Operator ("MISO") are two examples of resource adequacy programs without mandatory auctions.

A. The CAISO Bilateral Model

California has rejected the mandatory centralized capacity market on more than one occasion. Most recently, the CAISO committed to the California legislature that it would not file at FERC to move to such a structure unless certain conditions occurred.[1] The commitment is generally believed to have been in exchange for the legislature dropping consideration of SB

[1] Letter from Steve Berberitch to The Honorable Darrell Steinberg, President Pro Tempore, California State Senate (May 22, 2014).

1277, which, if passed, would have forbidden CAISO to make such a filing. While the constitutionality of such a law would have been highly questionable, California has made its wishes clear. Its opposition is grounded in its concern for its state jurisdictional priorities. In addition to its aggressive Renewable Portfolio Standard ("RPS"), California mandates that its utilities invest in storage, distributed generation, energy efficiency and demand response (to name a few), and is not interested in any mechanism that would prevent or penalize deployment of preferred resources through a Minimum Offer Price Rule ("MOPR") or any other price-based mechanism.

For now, the CAISO resource adequacy program remains based on self-supply and bilateral contracts. CAISO requires each load-serving entity ("LSE") to procure three types of resource adequacy ("RA") capacity—System, Local, and Flexible.[2] CAISO sets the reserve standard for all three categories of RA capacity, but allows local regulatory authorities[3] to set their own reserve number for system RA. CAISO currently sets RA targets once a year for the upcoming year; each local regulatory authority is responsible for ensuring its LSEs have procured enough capacity for the year. CAISO expects to expand its program to incorporate multi-year forward procurement targets when the CPUC finishes its proceedings to set those targets for its jurisdictional investor owned utilities ("IOU").

Once the requirements are set, each LSE either self-supplies its share of each category of RA, or contracts for capacity on the bilateral market. CAISO sets default rules for counting how much RA capacity any particular resource can provide, but local regulatory authorities are permitted to set their own counting rule for generic RA. CAISO requires each LSE to make

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[2] At the time of writing, the requirement to procure flexible capacity is still pending before FERC in Docket No. ER14-2574.

[3] Local regulatory authorities include the California Public Utility Commission ("CPUC"), and the state, and local governments with jurisdiction over state and municipal utilities.

monthly and annual showings that it has procured sufficient capacity to meet its obligations in each RA category. Once an LSE declares that a resource is being used to satisfy its RA obligation, that resource is designated as RA capacity and becomes obligated to offer energy and ancillary services into the CAISO markets according to specific rules that vary based on resource characteristics and RA category.

CAISO also maintains backstop procurement authority. After receiving annual and monthly showings from each load-serving entity, CAISO evaluates whether it has sufficient System, Local, and Flexible capacity. If CAISO determines that there is a deficiency in any category, it has the authority to procure additional backstop capacity. CAISO will offer resources that are available a fixed price to provide RA capacity on a backstop basis. The fixed price is the result of a 2011 settlement between various California parties, including load-serving entities and merchant generators.

B. MISO

MISO resource adequacy occupies a middle zone between the organized markets of the East and CAISO—there is an auction, but it is voluntary, and LSEs continue to rely largely on bilateral contracts and self-supply. MISO establishes annual fixed reliability targets for each capacity zone, and LSEs may meet their respective portion by either opting into the annual capacity auction (where self-supply in the form of bilateral contracts may be bid at zero in the auction) or opting out of the auction by submitting a Fixed Resource Adequacy Plan ("FRAP").[4] Unlike other regions, such as PJM, LSEs are not required to choose one option or the other. Thus, although MISO LSEs can cover all of their annual resource requirements, they can choose

[4] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,283, *reh'g denied*, 125 FERC ¶ 61,061 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,199 (2012) ("2012 Order").

to cover part of their load under a FRAP and procure the balance of needed zonal resource credits (i.e. the credits needed to meet their resource adequacy target) through the auction.

To ensure there is sufficient capacity throughout its 15-state footprint, MISO requires that LSEs arrange to meet the load in their respective load zones (with limited grandmothering for loads historically served by resources in other zones). Further, LSEs with supplies in excess of their loads must offer those amounts into the market.

Unlike the eastern markets, MISO capacity market bids are not subject to a MOPR. FERC considered and rejected this idea in 2012.[5] But in 2013, FERC seemingly reversed course and ordered supplemental briefing on its initial rejection of the MOPR.[6] After a year of no action, a group of capacity suppliers recently submitted a motion seeking expedited action, an order requiring a mandatory capacity market for buyers and sellers, a MOPR, the elimination of the ability to opt-out under the FRAP, and the establishment of a three-year planning commitment with a downward sloping demand curve.[7] The comment deadline has since passed, and FERC has not yet acted.

II. WHERE DO CAPACITY MARKETS GO FROM HERE?

With capacity markets in the East failing to accomplish their goals and further failing to entice other states and many market participants in the rest of the country to willingly follow suit, FERC's capacity market policy stands at a crossroads. EPA's proposed rule to govern carbon emissions from existing coal-fired power plants introduces further uncertainty into the market structure. Introducing a carbon price into the markets could potentially address certain problems that have arisen out of the organized capacity markets, such as nuclear plants in danger

[5] 2012 Order, P 70.

[6] *Midwest Indep. Transmission Sys. Operator, Inc*., 144 FERC ¶ 61,125 (2013).

[7] Motion for Expedited Action, Aug. 25, 2014, *Midwest Indep. Transmission Sys. Operator, Inc*., Docket No. ER11-4081, eLibrary No. 20140825-5176.

of closing due to insufficient revenues. However, coal plant retirements could throw capacity markets into even greater uncertainty, and are likely to further increase costs.

A. Price Formation in the Energy Markets: Back to the Future?

Over the past year, the events of the polar vortex, the increased significance of renewable portfolios, and repeated suggestions from a range of market participants have moved FERC to consider whether a solution to the problems with centralized capacity markets might be found by addressing price formation issues in the energy markets. FERC has opened a new docket[8] and is convening a series of technical conferences to consider these issues.

The attraction of such an approach is clear. Capacity markets have proven to be both highly complex and prone to unanticipated consequences. While the same observations can be made with regard to energy markets, capacity markets run relatively infrequently, and it can be years before the results of a particular auction can be assessed against actual market needs, especially in regions where capacity markets run several years forward. By then, it is too late to adjust for over- or under-procurement. In contrast, the energy and ancillary services markets run daily, and in some cases as often as every five minutes. The Commission can understand how its adjustments are performing much more quickly. Further, to the extent that price formation reforms in the energy market increase revenues to generators who might be at risk of retirement, there would be less risk when capacity markets fail to perform as well as hoped.

The Commission price formation concerns include:[9]

- Technical limitations in market software may prevent RTOs from fully modeling all physical constraints, leading to operator corrections with out-of-market dispatch.

[8] Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14-000.

[9] Notice, June 14, 2014, Docket No. AD14-14-000, eLibrary No. 20140619-3043.

- Market clearing prices may not reflect all components of a unit's operating cost, leading to uplift payments, which distort price signals.
- Demand remains largely price insensitive.

Recognizing that not all of these problems can be addressed at once, the Commission is targeting four specific issues to be examined in detail in upcoming technical conferences:

- Using uplift payments, especially when part of a sustained pattern rewarding a small number of specific resources;
- Offering price mitigation and price caps may prevent resources from recovering their full costs by preventing the resource from obtaining scarcity revenues;
- Scarcity prices set at inappropriate levels, and;
- Operator interventions that affect prices.

Separately, a number of entities have advocated improvement and augmentation of the ancillary services markets as preferable to the creation of individual capacity markets for attributes such as "flexibility." For example, CAISO's Market Surveillance Committee recently recommended that short-term markets, rather than capacity markets, should be the primary mechanism for incentivizing flexible capacity:[10]

> Finally, we conclude that short-term markets should be the primary source of economic incentives for providing flexibility to the CAISO system. There are two reasons for this conclusion. First, short-term energy, reserves, and flexiramp markets respond by providing energy precisely when needed during ramp periods, and thereby avoid the very serious conceptual and practical problems of trying to accurately evaluate the contribution of imports, storage, start-limits, energy-limits, and other attributes in resource adequacy markets. Second, whether there is a market failure in

[10] James Bushnell, *et al*., Members of the Market Surveillance Committee of the California ISO, *Opinion on Flexible Resource Adequacy Criteria and Must-Offer Obligation* (2014), *available at* http://www.caiso.com/Documents/Decision-FlexibleResourceAdequacyCriteriaMustOfferObligation-Final_MSC_Opinion.pdf.

> those short-term markets that would yield too little flexibility is not well understood. There are several changes that are being made or could be made to the CAISO markets to ensure that flexible resources are appropriately incented. These include creation of a flexiramp product; separation of day-ahead and real-time bid cost recovery; moving to 15 minute markets for interchanges under FERC Order 764; geographic expansion of the energy imbalance market; decreasing the use of out-of-market dispatch; and expanding scarcity pricing through appropriate reflection of energy imbalance and other constraint violation penalties in locational marginal prices. If these changes are successful and if flexible RA requirements are not overstated relative to actual system need, we anticipate in the long run that flexible RA capacity will receive little or no premium in the RA markets.

The thinking is that new or different ancillary services, such as ramping up, ramping down, or load following would better meet flexibility needs than a separate flexible capacity market. The concern with slicing up capacity markets into tranches for flexible characteristics—renewable resource portfolios, storage, existing vs. new resources, long-term contracts or any other resource type or characteristic—is that it forces the RTO to allocate the market among the various tranches, which amounts to a considerable amount of operator discretion to influence market outcomes.[11] In regions where capacity markets do not exist, market participants have argued that energy market pricing reform could eliminate or mitigate the need for capacity markets.

So far, only one of the technical conferences has occurred, with the next one scheduled for October 28. It is far from clear what lessons FERC will derive from the information presented, or what changes it might order. During the first conference, at least one Commissioner expressed a desire to gather the "low-hanging fruit" and to improve price formation in a relatively short time frame.

[11] Matthew Morey, *et al.*, Christenson Assocs. Energy Consulting, LLC, *Ensuring Adequate Power Supplies for Tomorrow's Electricity Needs*, 71-74 (2014), http://www.hks.harvard.edu/hepg/papers/2014/Ensuring%20Adequate%20Power%20Supplies%20for%20EMRF%20Final.pdf.

That desire notwithstanding, the amount of low-hanging fruit that exists is debatable. All of these issues can become very complex, very quickly, and the solutions are not always obvious. "Virtual bidding" in California is an example of this problem. CAISO implemented virtual bidding in its market in early 2011 with the intent to improve market efficiency and performance by reducing the price differences between its real-time and day-ahead markets.[12] Less than a year later, CAISO concluded that virtual bidding was actually causing real-time and day-ahead prices to *diverge* at intertie scheduling points, and thus filed at FERC to suspend virtual bidding at the interties.[13] Theoretical solutions to improve price formation can, in practice, produce unexpected results.

Similarly, the polar vortex event demonstrated that gas prices could, under extreme conditions, rise much more quickly than the gas price indices RTOs use to calculate a unit's start-up costs. The solution might seem to be allowing generation owners to use actual gas prices in the start-up cost component of their bids, but this solution overlooks the reasons why start-up bids were based on gas price indices in the first place. Generators who own many units and buy large quantities of gas often have large gas portfolios, making it problematic to link a specific gas purchase to a specific generating unit operating on a specific day. The index is used to avoid creating opportunities for generators to game their bids by making creative calculations to derive their start-up costs. Moving away from use of the indices would require a different solution to that problem.

Finally, of course, adoption of the various proposals made (and yet to be made) in the technical conferences would likely result in raising prices in the energy and ancillary service

[12] *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,039 (2010), *on reh'g*, 134 FERC ¶61,070 (2011), *on reh'g*, 136 FERC ¶ 61,056 (2011).

[13] *Cal. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,087 (2013).

markets. Such an outcome would likely be very unpopular with load interests, unless there was a clear parallel to lower costs in the capacity markets. We do not know where this series of technical conferences will lead, but the outcome may have significant impacts on capacity markets and proposals to reform them.

B. Carbon Pricing and Capacity Markets

A wild card likely to have a significant impact on the direction capacity markets will take in the future is the EPA Clean Power Plan, the Notice of Proposed Rulemaking under which the EPA proposes to regulate the emissions of CO2 from existing power plants.[14] The comment period on the proposed rule is scheduled to close on December 1, 2014, with the EPA planning to finalize the rule by June of 2015.

Without drilling down into a level of detail that exceeds what is required to discuss capacity markets, the rule would set state-specific emissions guidelines that include rate-based CO2 emissions targets (which could be converted to mass-based targets) based on EPA's determination of the Best System of Emissions Reduction ("BSER"). The EPA is proposing to use four "building blocks" as its BSER. Those building blocks, *i.e.* the various tools EPA has proposed could be deployed to reduce a state's overall CO2 emissions, are:

- Block 1: Improve the average heat rates of coal-fired power plants by 6%.
- Block 2: Dispatch existing natural gas combined cycle ("NGCC") units in lieu of coal-fired and oil/gas-fired steam powered electric generating units, attaining an annual average capacity factor of 65% or more.

[14] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014) (to be codified at 40 C.F.R. pt. 60), *available at* http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf.

- Block 3: Shift energy production to lower carbon producing sources by increasing renewable energy capacity construction, completing all nuclear units currently under construction and avoiding the projected retirements of certain nuclear capacity, estimated at six percent of each state's historical nuclear capacity.
- Block 4: Increased demand-side energy efficiency and demand response programs to reduce the need for new generation units.

States could use these building blocks or other measures as a portfolio to attain their assigned emissions reductions. States could also deny permits to coal-fired power plants or limit their permitted operating hours to attain the target reductions. If a state fails to submit a plan, the EPA will impose a Federal Implementation Plan. Because it is beyond the EPA's jurisdiction to order things like redispatch, construction of renewables, avoidance of nuclear retirements or energy efficiency or demand response programs, an EPA-issued plan would likely be limited to shutting down the coal plants or restricting hours of operation for any emissions goal above what could be achieved by heat rate improvements.

States will have the option of submitting an individual plan ("State Implementation Plan" or "SIP"), or joining together with other states to create regional compliance plans.[15] In theory, regional compliance presents an opportunity for RTOs to integrate carbon prices into their operations by implementing portions of the compliance plans of their member states in their energy dispatch. Assuming an appropriate carbon price, a carbon adder could change the dispatch of the generation fleet in ways that could lower emissions; and lower the cost of emission reductions by more than states could manage on their own. Indeed, a regional compliance plan in RTO states offers the only practical means by which states can achieve

[15] 79 Fed. Reg. at 34,916.

building blocks two and three, since states do not typically control the dispatch order of resources located within their borders, nor do they have much influence on the revenue streams flowing to nuclear plants at risk of retirement. A carbon adder could direct increased revenues in the energy markets to nuclear plants in danger of retirement, which could help address fuel diversity concerns. Carbon prices are factored into energy bids in California and certain New England states, demonstrating that these programs can be incorporated into RTO energy markets without undue disruption.

Regional plans could also help with cross-border emissions impacts. For example, a utility could have load in three states and generation in yet another, all subject to separate state plans. A demand response program in one state may reduce generation and emissions in another. Closing a coal plant in one state may increase generation in another. A renewable resource in one state may sell its Renewable Energy Credits ("REC") out of state. EPA has not yet successfully grappled with the difficulty of accounting for cross-border effects in individual state plans. A regional plan could help distribute credit for all state efforts appropriately. Not surprisingly, the ISO/RTO Council ("IRC") sees a role for its members in measuring compliance with regional plans.[16]

1. **Challenges for Creation of RTO Regional Plans**

Notwithstanding the potential benefits of creating regional or sub-regional compliance plans within RTOs, there are a number of factors working against this outcome. Difficulties include:

[16] ISO/RTO Council, *EPA CO_2 Rule- ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals* (2014) ("IRC CO_2 White Paper"), http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.

- Timing: Even with the lengthy comment period on the EPA rule, many states are still struggling to grasp the compliance implications within their own borders. They are far from looking at regional plans at this time, and implementation of the rule, if it is allowed to go forward, will take much longer than the EPA now contemplates.
- Non-compliance: It is quite possible that some states will choose not to submit a plan. Absent cooperation from the state legislature and the governor's office, some states may not be able to form a plan. If such a state is in a RTO, what impact will its decision have on the states around it?
- Consistency: In order to form a successful regional plan, states must coordinate on basic decisions (such as whether to use a rate-based or mass-based standard). What if they cannot agree?
- Leaders and laggers: States that are currently in a good position to achieve compliance with their emissions targets might have little incentive to pool their obligations with states that are far behind, much the same as regions with lower power prices have had little incentive to form or join RTOs.
- State borders do not match RTO borders: Some states are divided between RTOs, or between RTO and non-RTO regions. Since each state must create a plan that covers the entire range of sources within its borders, they might have to participate in multiple regional plans.
- Jurisdiction: Many states already believe that too much of their jurisdiction has been ceded to RTOs and will be reluctant to cede any more.

- Demand response pricing is uncertain: In the wake of the DC Circuit decision[17] striking down FERC's Order No. 745 on demand response pricing in energy markets, the role of demand response in organized markets is completely uncertain, and may remain so for some time.
- MOPRs and renewable energy: ISO-New England failed to obtain an exemption from the market clearing requirement for renewable resources.[18] Although a limited exemption exists in PJM, FERC's view is that guaranteed clearing for any type of resource undermines the market. A problem for RTO regional plans is the fact that the MOPR construct is not compatible with the concept of must run or must take renewable resources in the markets.
- Flexibility Challenges: Increased reliance on intermittent renewable resources increases the need for dispatchable units that can balance the steep ramps occurring when intermittents go on and off line due to wind or solar conditions. There is tension between this need and the EPA's desire to see NGCC units displace coal. Coal units operate at baseload for a reason, and if NGCC units must assume that role, many more will be needed to balance the grid.

2. **Reliability and Retirements**

Although it is unknown how carbon pricing will affect bids in the energy markets, there is no doubt that the coal plant retirements envisioned by the rule will have an impact on reliability and the capacity markets. It is already clear that the RTOs are concerned about

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[17] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. May 23, 2014*), reh'g en banc denied*, No. 11-1486 (D.C. Cir. September 17, 2014).

[18] ISO New England, Inc., 142 FERC ¶ 61,108 (2013).

resource adequacy in the face of coal plant retirements.[19] An initial analysis conducted by MISO suggests compliance could drive the retirement of an additional 14 GW of coal plants beyond those already announced.[20] Of course, much depends on the assumptions used. The MISO analysis claimed to find substantial cost savings over individual state plans. It is also significant that the same MISO study determined that applying the EPA building blocks and rate-based approach to the fifteen states MISO reaches would cost about $60 a ton, well above EPA cost estimates.[21] The MISO estimate did not include transmission upgrades or new gas pipelines.

Reliability concerns are already central to any discussion of the proposed rule. In a white paper on the proposed rule, the IRC suggested establishing a Reliability Safety Valve ("RSV"). Through the RSV, the ISO or RTO would perform reliability assessments in advance of final SIP approval.[22] Since operational restrictions on a plant located in one state can affect reliability in other states, the reliability assessment would address regional SIP effects. The IRC believes the RSV process should include potential interim measures keeping units online while a longer term solution is developed. If RTOs and ISOs can temporarily veto the retirements of units in states within their borders, this will have implications for achievement of state plans. Obviously, the RSV proposal could affect the viability of individual state plans.

Tied to the question of reliability, FERC is already facing issues related to whether retirements of coal-fired plants might be made for anticompetitive reasons to manipulate capacity

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[19] Moeller *et al.*, Update on MISO 2016 Resource Adequacy Forecast, Sept. 18, 2014, http://www.ferc.gov/CalendarFiles/20140918110305-A-3-total.pdf.

[20] Matthew Bandyk, *MISO sees EPA CO_2 rule driving another 14 GW of coal retirements*, SNL Financial (Sept. 17, 2014), https://www.snl.com/InteractiveX/article.aspx?ID=292467404KPLT=2 (subscription required).

[21] Jeffrey Tomich, MISO Study Suggests Bigger is Better When it Comes to EPA Carbon Compliance," EnergyWire (Sept. 18, 2014). http://www.eenews.net/stories/1060006050.

[22] IRC CO_2 White Paper at 2.

market prices. Given the extensive retirements of coal-fired EGUs anticipated as a result of this rule, coal plant owners are damned if they retire the emits and damned if they don't.

The first such case has already been brought to FERC's attention by way of ISO-New England's eighth capacity auction ("8th FCA") results[23] in which: (1) the total price tag of the auction compared to previous years increased by over $1 billion, and (2) in an area that has traditionally been resource long, the auction closed with less capacity selected than ISO-NE needed for the 2017-18 year. While there were administrative changes to this auction (i.e. higher default price, first auction with MOPR),[24] the main issue was a dispute centered on the announced retirement of Brayton Point, a coal-fired generator with over 1500 MW capacity. On January 27 of this year, Brayton Point Energy notified ISO New England that it would retire the plant on June 1, 2017, coincident with the 8th capacity market commitment period. The announced retirement had the effect of moving ISO-New England from a surplus capacity condition to a deficit for the commitment period, and the deficit could not be addressed before the auction. ISO-NE certified that the auction was non-competitive, and set the clearing price using the administrative rules applicable to non-competitive situations.

When ISO-NE filed the results of the auction at FERC, numerous government entities from the New England states, citizen's organizations and consumer groups filed protests.[25] Short one Commissioner, the Commission deadlocked on a two/two tie. Chairman LaFleur and Commissioner Moeller would have found the auction to be just and reasonable, while future Chairman Bay and Commissioner Clark would have set the matter for hearing. The Commission

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[23] Forward Capacity Auction Results Filing, Feb. 28, 2014, Docket No. ER14-1409, eLibrary No. 20140228-5324.

[24] *New England Power Generators Ass'n, Inc. v. ISO New England Inc*., 146 FERC ¶ 61,038 (2014); *ISO New England, Inc.*, 131 FERC ¶ 61,065, *on reh'g and clarification*, 132 FERC ¶ 61,122 (2010), 135 FERC ¶ 61,029 (2011), and 138 FERC ¶ 61,027 (2012), *review denied New England Power Generators Ass'n. v. FERC*, 757 F.3d 283 (D.C. Cir. 2014).

[25] *See* Docket No. ER14-1409.

failed to act on the tariff filing prior to its statutory deadline, consequently, the filing became effective by operation of law.[26]

All the Commissioners issued statements elucidating their views: Chairman LaFleur and Commissioner Moeller favored regulatory certainty for generation owners and a decision not to disturb auction results conducted in accordance with the tariff. Commissioners Bay and Clark stated that FERC should not refuse to investigate an alleged abuse of market power, which ISO-NE stated was unmitigated. Further, they argued that the Commission's assurance that it would review the reasonableness of market results was rendered illusory by the failure to review these results.

CONCLUSION

Between the potential reforms in the daily energy markets and the proposed EPA rule, altering the dispatch from least-cost economic dispatch could carry tremendous potential for prices to rise in all markets. On the other hand, because FERC seems inclined to pursue changes aggressively and the industry will need to implement whatever rule emerges from the EPA process, there is a potential for altering historic capacity market structures and assumptions. The risks are high, but involvement in both of these regulatory efforts may also offer the most promising opportunities for re-engagement with FERC on the question of self-supply. In this case, the need to change the markets may also be the catalyst for improvements APPA members seek.

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[26] Notice of Filing Taking Effect By Operation of Law, Sept. 16, 2014, *ISO New England, Inc.*, Docket No. ER14-1409, eLibrary No. 20140916-3065.

CAPACITY MARKETS AND RESOURCE ADEQUACY

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October 19, 2014

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BEYOND CENTRALIZED CAPACITY MARKETS

- Centralized capacity markets are not working
- CAISO and MISO have resource adequacy programs without mandatory auctions
  - CAISO bilateral model
  - MISO's voluntary auction
- Looming energy market changes may be a catalyst for capacity market reform
  - FERC's Price Formation workshops
  - EPA's Clean Power Plan could radically alter least-cost economic dispatch

SPIEGEL & McDIARMID LLP

CAISO'S RESOURCE ADEQUACY PROGRAM

- California choices
- Based on self-supply and bilateral contracts, not a centralized market
- LSEs must procure three types of capacity—System, Local, and Flexible
- LSEs procure resources to satisfy the reserve standards
- LSEs make annual and monthly showings that they have procured sufficient capacity
- CAISO maintains backstop authority; acquires shortfall for fixed price

SPIEGEL & MCDIARMID LLP

MOPR – FREE ENVIRONMENT WITH LIMITIATIONS

- CAISO quantifies need for each category and what resources can satisfy. Local Regulatory Authorities can establish need for System RA and qualifying resources
- CAISO sets requirements for local and flexible capacity
- LSE's may-self-schedule System RA resources or provide economic bids
- Flexible RA resources must offer economic bids in energy and ancillary services market in certain hours

  Flexible Resource Adequacy Capacity – Must Offer Obligation (FRAC-MOO); 149 FERC ¶ 61,042 (October 16, 2014)

SPIEGEL & MCDIARMID LLP

MISO'S RESOURCE ADEQUACY CONSTRUCT

- MISO sets annual zonal Fixed Reliability Targets
- LSEs meet respective planning resource requirement
  - Opt-in to Auction
  - Opt-out by submitting a Fixed Resource Adequacy Plan
  - Combination of two

Midwest Indep. Transmission Sys. Operator, Inc., 122 FERC ¶ 61,283 (2008) (conditionally accepting MISO's Resource Adequacy proposal), *reh'g denied*, 125 FERC ¶ 61,061 (2008).

Midwest Indep. Transmission Sys. Operator, Inc., 139 FERC ¶ 61,199 (2012)(June 2012 Order)(among other things, rejecting mandatory auction and MOPR, but accepting zonal charges and annual auction construct).

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AUCTION DESIGN

- Voluntary Auction (for now)
- Annual Auction
  - Two months forward
- No MOPR (June 2012 Order, 66-69)
- Self-scheduled resources (e.g. Self supply, bilateral contracts) bid $0 and receive the auction clearing price
- Capacity deficiencies are met by either paying a capacity deficiency charge or procuring capacity through the Planning Resource Auction
- Zonal Deliverability Charge (June 2012 Order, PP 71-77)
  - Load in one zone acquiring capacity resources from an external zone is subject to a deliverability charge
  - Limited grandmothering until end of 14/15 planning period for LSEs using historical external capacity resources

SPIEGEL & McDIARMID LLP

MISO FIXED RESOURCE ADEQUACY PLAN

- FRAP participation declared before each annual auction for all or part of LSEs annual requirements; can change inclusion from year to year.
- If supplies greater than FRAP, excess must be offered into the market, subject to a 50 MW withholding threshold
  - See June 2012 Order, P 41 "the withholding of supplies in excess of FRAP can represent an exercise of market power"; *see also id.* P 260.

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MISO UNCERTAINTY
DOCKET ER11-4081

- Aug. 2013- FERC order initiating briefing on rejection of MISO's MOPR proposal.

Midwest Indep. Transmission Sys. Operator, Inc., 144 FERC ¶ 61,125 (2013)

- Aug. 25, 2014- Capacity Suppliers Motion for Expedited Action

eLibrary No. 20140825-5176

  - Mandatory market for suppliers and buyers
  - MOPR
  - Eliminate FRAP
  - Three-year planning commitment
  - Downward sloping demand curve
- Sept. 9, 2014- Comment deadline
- FERC has not yet acted

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ADDRESSING CAPACITY MARKET ISSUES: ENERGY MARKETS

- Price formation issues in energy markets
  - Concerns:
    - Out of market dispatch due to technical software limitations that prevent full modeling of physical constraints
    - Uplift payments distorting price signals
    - Demand is largely price insensitive
  - Issues being examined by the Commission
    - Beneficial uses of uplift payments
    - Whether price mitigation and price caps prevent resources from recovering their full costs
    - Scarcity prices set at inappropriate levels
    - Operator interventions that affect prices

  Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14-000

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ADDRESSING CAPACITY MARKET ISSUES: ANCILLARY SERVICES MARKETS

- Centralized capacity markets are poor vehicles for procuring multiple tranches of capacity, e.g. flexible resources, RPS, storage, existing vs new resources, multiple capacity zones, etc.
- Properly designed ancillary services may be preferable to the creation of multiple capacity products.
- Short-term markets can incentivize specific attributes, such as flexibility, precisely when they are needed
- Short-term markets can be adjusted and refined based on immediate performance, instead of waiting years to evaluate the results of a forward auction.

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DOWNSIDE OF DAILY MARKET APPROACH

- Fixes tend to raise prices in daily markets
- Unintended consequences
- The rules were set up that way for a reason – increased complexity
- Technical Conferences

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ADDRESSING CAPACITY MARKET ISSUES CARBON PRICING

- EPA Clean Power Plan
- EPA sets state-specific emission guidelines that include state specific rate-based CO_2 emission goals based on the "best system of emission reduction" (BSER).
- Emission Goals based on four building blocks
  - Block 1: Improve by 6% the average heat rates of coal-fired electric generating units (EGUs);
  - Block 2: Dispatch existing natural gas combined cycle plants in lieu of coal-fired and oil/gas-fired steam powered EGUs;
  - Block 3: Shift energy production to lower carbon producing sources by: increasing renewable energy capacity, completing all nuclear units currently under construction; and avoiding the projected retirement of six percent of each state's historical nuclear capacity;
  - Block 4: Increase demand-side energy efficiency rates.
- Portfolio approach
- Individual state implementation plan (SIP) versus regional compliance

U.S. Envtl. Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Proposed Rule, 79 Fed. Reg. 34830 (June 18, 2014)(to be codified at 40 CFR Part 60), *available at* http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

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BENEFITS TO RTO REGIONAL CARBON PLANS

- Proven potential—existing market mechanisms have already incorporated carbon reductions
- Carbon adder
  - Environmental Dispatch
  - Could aid plants at risk of retirement
- Could address cross-border emission impacts

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CHALLENGES TO RTO REGIONAL CARBON PLANS

- Timing
- Non-compliant states
- Reaching an agreement
- Existing leaders and laggers
- Some states only partially located in an RTO
  - Multiple regional plans
  - Coordination across RTO seams
- Jurisdiction
- Pricing uncertainty for demand response

Elec. Power Supply Ass'n v. FERC, 753 F.3d 216 (D.C. Cir. May 23, 2014), *reh'g en banc denied*, No. 11-1486 (D.C. Cir. Sept. 17, 2014)(*vacating sub nom*. Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011), *clarified*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012))

- MOPRs and Renewable Energy

ISO New England, 142 FERC ¶ 61,108 (2013), *reh'g pending* (rejecting State requests for a renewables exemption)

- System flexibility needs

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GENERATION RETIREMENTS

- Reliability concerns
  - MISO projecting Clean Power Plan will lead to an additional 14GW of coal plant retirements

    9.18.2014 Commission meeting, presentations on MISO's resource adequacy forecast (Docket AD14-3) http://www.ferc.gov/CalendarFiles/20140918110305-A-3-total.pdf
  - Reliability Safety Valve
- Could inclusion of GHG lead to Market Manipulation?
  - Longer planning scheme = greater ability to manipulate forward markets
  - ISO-NE 8th Annual Capacity Market Precursor

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ISO-NE 8TH FORWARD CAPACITY AUCTION

- Prior to auction, pricing rules modified increasing default price

  New England Power Generators Ass'n, Inc. v. ISO New England Inc., 146 FERC ¶ 61,038, (2014).
- Brayton Point Retirement, 1500 MW + coal fired resource
  - Timeline
    - Oct. 18, 2013 Brayton Point Energy submits a binding request to retire
    - Dec. 20, 2013, ISO-NE determines plant needed for reliability and rejects retirement request
    - Jan. 27, 2014 Brayton Point Energy provides notice that it would retire plant on June 1, 2017 (i.e. coincident with 8th FCA Capacity Commitment Period)
  - Moved NE from surplus to deficiency condition
  - Due to timing of announcement "impossible" to fill shortfall
- ISO-NE certifies auction was non- competitive, Docket No. ER14-1409
  - Clearing prices set through administrative pricing rules
  - Total cost greater than $3 billion (versus first seven auctions ranging from $1.06-1.77 billion)
  - Auction closed with less capacity than needed for 2017-18
- Public power, states, unions, and others complain

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FERC DEADLOCKED

- Commissioners Bay and Clark favor hearing
  - "[T]here is evidence suggesting the exercise of market power, and it is uncontroverted that the market power, if it existed, was not mitigated. . . To the extent any portion of those prices was attributable to an exercise of market power, the auction will have imposed unwarranted costs upon consumers."
  - "To now assert that the [filed rate] doctrine precludes an examination of auction results renders illusory the Commission's prior assurance it would undertake a 'thorough review of the final auction clearing prices.'"
- Chairman LaFleur and Commissioner Moeller would have found just and reasonable
  - "It is [] imperative that the rules governing the FCA be transparent and that auction participants not be subject to significant regulatory uncertainty or after-the-fact ratemaking."
  - "[T]he only way to achieve different final rates would be to – implicitly or explicitly – retroactively revise the Commission-approved rules upon which ISO-NE conducted the auction and require ISO-NE to charge a rate not on file with the Commission."
  - "While markets do not always result in a low price, they will establish the best price to enable a matching of supply and demand."
- **End Result: Tariff accepted by operation of law**

  eLibrary No. 20140916-3065

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WHAT IS NEXT?

- Action in the energy markets may determine fate of capacity markets
- Carbon pricing could kill or cure capacity markets or just generate confusion and costs
- Energy pricing reform may be critical
- Infrastructure costs will increase

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Questions?

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October 15, 2014

RISK-BASED REGISTRATION: A RAY OF HOPE FOR RATIONALIZING NERC COMPLIANCE OBLIGATIONS

OCTOBER 2014 APPA LEGAL SEMINAR

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RISK-BASED REGISTRATION: A RAY OF HOPE FOR RATIONALIZING NERC COMPLIANCE OBLIGATIONS

OVERVIEW

The Energy Policy Act of 2005 added Section 215 to the Federal Power Act (FPA), which gives the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) (as the FERC-approved Electric Reliability Organization) authority to establish and enforce reliability standards on "all users, owners and operators of the bulk-power system," including public power entities. FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1). Under NERC's Rules of Procedure, reliability standards are mandatory and enforceable only against entities included on NERC's Compliance Registry. Over 1600 unique entities are currently on the NERC Compliance Registry.[1] This includes more than three hundred public power entities, including some that are very small.

In response to concerns about unnecessary burdens resulting from holding small entities responsible for NERC compliance, NERC has undertaken the Risk-Based Registration Initiative (RBR), with the goal of partially reversing the growth in burden where not justified by risk posed to reliability. If approved by the NERC Board of Trustees and FERC in its current form, RBR would eliminate three functional registration categories, raise the registration threshold for another, and limit responsibilities for some lower-risk entities that remain registered. The initiative is also intended to improve registration procedures, and increase uniformity in registration decisions.

[1] NERC, NERC Compliance Registry List, Summary (Aug. 27, 2014), http://www.nerc.com/pa/comp/Registration%20and%20Certification%20DL/NERC_Compliance_Registry_Matrix_Summary20140827.pdf.

Drafts of various RBR documents were most recently posted on August 26, 2014 for a 45-day public comment period that just concluded (on October 10),[2] with the expectation of seeking NERC Board of Trustees approval in November, and then filing for FERC approval. NERC contemplates implementation by the end of 2015.[3] Because the documents are not yet final, and neither NERC Board of Trustees nor FERC approval is assured, uncertainties remain. We believe, however, that the initiative shows real promise to provide needed reduction in unwarranted compliance burdens on all involved (over-registered entities, NERC, and its Regional Entities), while allowing resources to be freed up to focus on activities that yield far greater reliability benefits than ensuring compliance with reliability standards by entities whose actions can have minimal, if any, effect on the bulk power system.

REGISTRATION

FERC and NERC have jurisdiction over *all* "users, owners, and operators" of the bulk power system. FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1). When the legislation that became Section 215 of the Federal Power Act was being drafted, many expected NERC standards to apply to the larger entities whose actions needed to be subject to reliability standards "to provide for the reliable operation of the bulk power system" (FPA § 215(a)(3), 16 U.S.C. § 824*o*(a)(3)) so that "instability, uncontrolled separation and cascading failures of the [bulk power] system will not occur as a result of a sudden disturbance, including cybersecurity incident, or unanticipated failure of system elements" (FPA § 215(a)(4), 16 U.S.C. § 824*o*(a)(4)). As defined by Section 215, "bulk-power system" means "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)" and "electric energy from generation facilities needed to maintain transmission system reliability" but the term "does not include facilities used in the local distribution of electric energy." FPA § 215(a)(1), 16 U.S.C. § 824*o*(a)(1).

In the rulemaking processes associated with implementing Section 215, NERC proposed using a Statement of Registry Criteria to identify entities that should come forward to be registered (or be subject to registration by NERC) for compliance and enforcement with reliability standards,[4]

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[2] The August 26 posting is available under the "Proposed Revisions" tab at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. Unless otherwise specified, all references to RBR in this paper refer to the documents included in that posting. For convenience, we are attaching the version of Appendix 5B to NERC's Rules of Procedure, the Statement of Compliance Registry Criteria, that was included in the August 26 posting) ("Draft Registry Criteria").

[3] *See* Implementation Plan, which is Appendix A to the August 2014 Risk-Based Registration Phase 1–Enhanced Draft Design Framework and Implementation Plan, http://www.nerc.com/FilingsOrders/us/ruleofProcedureDL/August26_EnhancedDraftFrameworkandImplementationPlan_Final.pdf.

[4] Motion for Leave to File Reply Comments and Reply Comments of North American Electric Reliability Council and North American Electric Reliability Corporation, Docket No. RR06-1-000 (June 12, 2006), eLibrary No. 20060612-5082 ("2006 NERC Answer").

and which would then be placed on a list. This approach would provide certainty to all involved as to which entities are subject to compliance obligations, which come with the potential for enforcement through penalties of up to $1 million per violation per day. NERC's proposed Registry Criteria generally excluded from registration entities that did not meet specified criteria (e.g., as to assets owned or operated, or size/connection voltage).

FERC was initially leery of placing limitations on reliability obligations: in the Order No. 693 NOPR[5] (the rulemaking in which FERC approved the first set of NERC standards), FERC proposed to reject NERC's proposed Statement of Compliance Registry Criteria,[6] calling it a "blanket waiver" that was inappropriate because there could be instances where a small entity's compliance was critical to reliability (Order No. 693 NOPR, P 51).[7] Instead, FERC "propose[d] to direct NERC to take… factors [such as entity size and role] into account in determining applicability, as well as compliance requirements, *for a particular Reliability Standard*." *Id.* (emphasis added).

In response to significant pushback from the American Public Power Association (APPA), Transmission Access Policy Study Group (TAPS), and others, however, FERC's Order No. 693 accepted the Registry Criteria in substantially the same form that they exist now.[8] As a result, compliance with NERC standards is mandatory only for entities that are listed on NERC's Compliance Registry for a function (e.g., Generator Owner, Distribution Provider, or Balancing Authority), and only with respect to standards that identify that function in their applicability

[5] Notice of Proposed Rulemaking re Mandatory Reliability Standards for the Bulk-Power System, 117 FERC ¶ 61,084, Docket No. RM06-16 (Oct. 20, 2006) ("Order No. 693 NOPR").

[6] *See* 2006 NERC Answer, Appendix B. The Registry Criteria as proposed in June of 2006 were significantly revised and refined before FERC ultimately accepted them, but the key components—the size-based thresholds for some functions, and the ability to reach below that line to register an entity that is material to BPS reliability—remain substantively unchanged from what NERC proposed at that time.

[7] At the same time, the Order No. 693 NOPR proposed to apply reliability standards to transmission to all significant local distribution systems (but not the distribution system itself), transmission to load centers and transmission connecting generation that supplies electric energy to the system, as well as below-100 kV facilities that could limit or supplement the 100 kV+ transmission systems). Order No. 693 NOPR, P 68. FERC ultimately relented on that approach as well, agreeing in Order No. 693 to rely, at least initially, on the Bulk Electric System definition, discussed below. Order No. 693, P 75.

[8] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 118 FERC ¶ 61,218, 72 Fed. Reg. 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007), *effective date stayed*, 72 Fed. Reg. 31,452 (June 7, 2007) ("Order No. 693"), *aff'd*, Order No. 693-A, 72 Fed. Reg. 40,717 (July 25, 2007), 120 FERC ¶ 61,053 (2007); *see* Further Comments of Transmission Access Policy Study Group in Support of Supplemental Filing of North American Electric Reliability Corporation, Docket No. RM06-16-000 (Feb. 13, 2007), eLibrary No. 20070213-5045; Supplemental Comments of the American Public Power Association, Docket No. RM06-16-000 (Feb. 14, 2007), eLibrary No. 20070214-5050.

sections.[9] The Statement of Compliance Registry Criteria includes limitations on registration for some functions based on size and connection voltage, so that the smallest entities are not registered in the absence of a determination that a particular small entity is material to reliability. While a significant improvement over the Order No. 693 NOPR, the Registry Criteria limitations were—and are—overly conservative; the thresholds are too low, and thus sweep in many small entities that do not have a material impact on BPS reliability. RBR proposes to improve this situation.

A) Current Registry Criteria

The Statement of Compliance Registry Criteria consists of several parts that build upon each other. Part I states that "[e]ntities that use, own or operate Elements of the Bulk Electric System as established by NERC's approved definition of BES below are (i) owners, operators, and users of the Bulk Power System and (ii) candidates for Registration," and quotes the current Bulk Electric System (BES) definition.[10] Part II then states NERC's current functional type definitions to provide an initial determination of the functional types for which the entities identified in Part I should be considered for Registration. Part III lists criteria limiting the registration of entities that were selected to be considered for registration pursuant to Parts I and II for certain functions.[11] Parts IV and V, respectively, deal with joint registration (e.g., where a joint action agency registers for compliance obligations of its members) and NERC obligations to add entities to the Compliance Registry. Finally, Notes identify grounds for registering an entity that does not meet the Registry Criteria, or for declining to register an entity that does meet the Registry Criteria; whether an entity is demonstrated to have (or not to have) a material impact on BPS reliability trumps the outcome of Parts I through III of the Registry Criteria.

1. Part I: BES Definition

The Registry Criteria have already been updated to incorporate the new BES definition, which went into effect on July 1, 2014. The new definition is significantly clearer and more granular than the original, which simply read "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial

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[9] Compliance obligations apply prospectively from the date of registration for a particular function. Order No. 693, P 97.

[10] NERC, Appendix 5B, Statement of Compliance Registry Criteria, Revision 5.1 (effective July 1, 2014) ("Current Registry Criteria"), Section Part I, http://www.nerc.com/FilingsOrders/us/RuleofProcedureDL/Revised_August262014_Appendix5B_StatementCriteria_Final.pdf.

[11] Load-Serving Entity (LSE), Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Transmission Owner (TO), and Transmission Operator (TOP).

transmission facilities serving only load with one transmission source are generally not included in this definition."[12] The new definition[13] consists of (1) a core definition of the BES as facilities over 100 kV; (2) bright-line "Inclusions" adding clarity to the core definition and including facilities that would not necessarily be covered by the 100 kV bright line (e.g., transformers with more than one winding over 100 kV; over-20 MVA generators connected at over 100 kV); (3) bright-line "Exclusions" excluding facilities that might otherwise be included by the 100 kV bright line (e.g., 100 kV+ radials serving load and/or less than 75 MVA of non-BES generation); and (4) a case-by-case exception process through which registered (and potentially registered) entities, Regional Entities, and NERC can include or exclude facilities that are not correctly categorized by the core definition, Exclusions, and Inclusions.[14] The core definition, Exclusions, and Inclusions are a set of bright lines intended to correctly categorize the vast majority of elements without the need for judgment calls. The exceptions process then handles the hard cases at the margins, with procedural safeguards to constrain the exercise of discretion.

While the new BES definition, which clarifies the set of equipment to which reliability standards generally apply, is now included in Part I of the Registry Criteria, it is not integrated into the remainder of the current Registry Criteria on a consistent basis.

2. Part II: Functions

Part II lays out the functions for which an entity can be registered. Of particular note in the RBR context, the current Part II definitions of TO and TOP refer to owning or operating transmission "Facilities." The capitalized term "Facility" is defined in the NERC Glossary and Rules of Procedure as "a set of electrical equipment that operates as a single *Bulk Electric System* Element" (emphasis added).[15] All references to "Facilities" in the Registry Criteria thus incorporate the new BES definition (including the outcomes of the BES exception process); something is a "Facility" if and only if it is part of the BES. However, the Registry Criteria's definitions of GO and GOP do not use the term Facility, but instead refer to owning/operating generating "units."

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[12] Order No. 693, P 75 n.47 (quoting NERC's definition of Bulk Electric System).

[13] Current Registry Criteria, Part I (*see also* attached Draft Registry Criteria, Part I).

[14] *See* NERC, Appendix 5C to the NERC Rules of Procedure, Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System (July 1, 2014), http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_5C_ProcForReqAndRecExFromAppOfNERCDefBES_20140701.pdf.

[15] NERC, Appendix 2 to the NERC Rules of Procedure, Definitions (July 1, 2014), http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_2_ROP_Definitions_20140701_updated_20140602_redline20140826%20-%207%20terms.pdf.

3. Part III: Additional Criteria for Certain Functions

Pursuant to Part III of the current Registry Criteria, LSEs are subject to registration if they have at least 25 MW peak load and are "directly connected to the Bulk Power (>100 kV) System."[16] A DP is registered if it is a "Distribution Provider system serving >25 MW of peak Load that is directly connected to the Bulk Power System."[17] In addition, DPs and LSEs of any size or connection voltage that participate in a required UFLS or UVLS program, and DPs that have a required Special Protection System or required transmission Protection System, are subject to registration.

Generator Owners and Generator Operators are registered if they own/operate an individual generator with more than 20 MVA nameplate capacity, or a plant with gross aggregate nameplate of 75 MW, directly connected to the BPS. Also subject to registration are owners and operators of any generator, regardless of size or interconnection voltage, that is a blackstart resource designated as material to the TOP's restoration plan or material to BPS reliability.[18]

Transmission Owners and Transmission Operators are subject to registration if they own/operate any "integrated transmission Element associated with the Bulk Power System 100 kV and above,"[19] or lower voltage as defined by the Regional Entity as necessary to provide for reliable operation of the grid, *or* any element, regardless of voltage, included on a Regional Entity's critical facilities list. This terminology has led to confusion, for example, regarding the registration implications of owning transformers with a single winding over 100 kV.

B) The Need for Reform

In the seven years of experience with enforcement of NERC standards, it has become clear that the current registration scheme has produced a great deal of over-registration. APPA, TAPS, and others have argued repeatedly over the years that the excessive number of registered entities results in significant and undue burdens both for small registered entities and for NERC and the Regional Entities, who are responsible for monitoring compliance of numerous small registered entities. This burden on all involved is disproportionate to any reliability benefit of keeping such small entities registered, and has the added effect of diluting NERC's reliability mission with unnecessary and costly distractions. A further problem is the lack of clear procedures and deadlines for entities to seek deregistration. Some specific problems are outlined below.

[16] Current Registry Criteria, Section III.a.1.

[17] *Id.*, Section III.b.1.

[18] *Id*., Section III(c).

[19] *Id.*, Section III.d.1.

The Registry Criteria include the commercial functions of Interchange Authority, Load-Serving Entity, and Purchasing-Selling Entity. The treatment of LSEs in the Statement of Compliance Registry Criteria and standards is particularly confused; the requirements in NERC standards applicable to LSEs often overlap with those imposed on the DP, and many relate to ownership or operation of elements of a distribution system,[20] even though the LSE role does not require ownership of any physical assets.[21] A further wrinkle was added when FERC, in a registration appeal by three competitive retail power marketers, construed the Registry Criteria's requirement that "Load-Serving Entity peak Load is > 25 MW and is directly connected to the Bulk Power (>100 kV) System"[22] to foreclose registration of an LSE that owns no physical assets, even if it fits the definition in Part II of the Registry Criteria, because the LSE itself is not "directly connected" to the BPS.[23] FERC noted that, even if the alternative interpretation were correct—that the *load* had to be directly connected to the BPS—NERC had not demonstrated that the retail power marketers' customers were "directly connected to," as opposed to "served through," the BPS.[24] To avoid any reliability gap, the Registry Criteria were revised to provide for DPs to be registered as the LSE for all load directly connected to their distribution facilities.

As noted above, while the Part II definitions of TO and TOP require ownership/operation of "Facilities" (a term which, as described above, ties to the new BES definition), the definitions of GO and GOP do not use that defined term, and are thus disconnected from the BES definition. Furthermore, the Part III limitations on registrations of GO/GOPs and TO/TOPs (Sections III.c and III.d) are similar but not identical to the BES definition. Unlike the current Part III of the Registry Criteria, the new BES definition excludes radials serving some generation, as well as radials serving only load, and further excludes certain "local networks"; and the current Part III does not automatically incorporate the results of the BES exception process, so that if even NERC finds that the only transmission element owned/operated by a registered TO/TOP is no longer part of the BES, deactivation as TO and TOP is not automatic.

With respect to DPs, LSEs, and GO/GOPs, Part III of the Statement of Compliance Registry Criteria refers repeatedly to direct connection to the Bulk *Power* System, but does not define it (although the term is defined, in general terms, in Section 215 of the FPA and in the NERC

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[20] *See, e.g.*, FAC-002-1, Coordination of Plans for New Facilities, http://www.nerc.com/files/FAC-002-1.pdf.

[21] The Statement of Compliance Registry Criteria defines the LSE as the entity that "[s]ecures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers." Current Registry Criteria, Part II.

[22] *Id.*, Section III.a.1.

[23] *Direct Energy Services, LLC*, 121 FERC ¶ 61,274, P 36.

[24] *Id*. PP 37-38.

Rules of Procedure). It is thus unclear whether, for example, a DP/LSE connected to a 138 kV "local network" is subject to registration—it is not directly connected to the BES, but is it directly connected to the BPS? While FERC recently applied the BES definition to make this determination,[25] NERC had argued that the existing language allowed greater flexibility. In addition, the peak load thresholds in Part III are too low, and raising them would not increase risk to BPS reliability.

There are also significant concerns about whether the general "all or nothing" approach to application of reliability standards imposes a burden disproportionate to reliability benefits. For example, a small TO/TOP is subjected to compliance with literally hundreds of requirements, even though it may own only a single limited BES transmission Facility, and lack the wide area view to meaningfully comply with many of the applicable standards. Similarly, small generators that rarely operate have questioned whether their compliance burden is unduly heavy, a consideration that will weigh against continuing to operate the generation in question.

The current procedures governing registration are problematic as well. For example, they contain no deadlines for Regional Entity action on requests for deactivation,[26] with the result that some deactivation requests have languished for significant lengths of time without action by the Regional Entity.

C) Risk-Based Registration

NERC's CEO, Gerry Cauley, has made Risk-Based Registration a major initiative for 2014, viewing it as the final cornerstone of his objective to move NERC to a more risk-informed enterprise. In recent years, NERC has adopted a more risk-informed approach to reliability standards[27] and to compliance and enforcement.[28] NERC now seeks to apply a risk-informed

[25] *S. La. Elec. Coop. Ass'n*, 144 FERC ¶ 61,050 (2013) ("*SLECA*").

[26] NERC refers to an entity's removal from the Compliance Registry for a particular function as "deactivation"; if an entity is deactivated for all functions for which it was registered, it is considered "deregistered."

[27] NERC strives for "results-based" standards, http://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx; *see also* Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards, Order No. 788, 145 FERC ¶ 61,147 (2013) (approving NERC's request to retire 34 reliability standard requirements that provide little protection for Bulk-Power System reliability or are redundant with other requirements).

[28] NERC's Find, Fix, Track, and Report (FFT) initiative (*see*, most recently, *N. Am. Elec. Reliability Corp*., 148 FERC ¶ 61,214 (2014)) and Reliability Assurance Initiative (RAI) (http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx) are aimed at making compliance and enforcement more risk-based. RAI does not affect the requirements with which an entity must comply (and document compliance), but it allows audits to be scoped on a more individual basis, and affects how instances of noncompliance are handled. RBR, on the other hand, could reduce or eliminate certain lower-risk entities' compliance obligations.

approach to registration, as well, to better focus resources where they will yield the maximum benefit to reliability.

The Risk-Based Registration Initiative, or RBR, is on a very aggressive schedule. In early 2014, NERC formed a Risk-Based Registration Advisory Group (RBRAG) consisting of representatives from industry, the Regional Entities, and FERC, as well as a Risk-Based Registration Task Force with members drawn from industry and the Regional Entities, charged with providing expertise with respect to the technical aspects of the initiative.

With the help of the RBRAG and the Task Force, NERC has developed a draft framework document and proposed revisions to the Rules of Procedure to implement RBR; the documents were posted for stakeholder comment in June, and again on August 26 for a 45-day comment period that has recently concluded. A draft technical report, intended to provide the technical basis for NERC and FERC approval of the proposals, was included in the later posting. The expectation is that the RBR proposal will be presented to the NERC Board of Trustees at the Board's November meeting, to be followed by a NERC filing for FERC approval.

KEY ELEMENTS OF RBR, AS PROPOSED IN THE AUGUST 26 FRAMEWORK AND ASSOCIATED DRAFT REVISIONS

A) Synchronize with the new BES definition

As discussed above, the new BES definition is significantly more granular than the original, and includes an exceptions process for adding elements to, or removing elements from, the BES, in cases where the definition does not properly categorize an element. The proposed revisions to the Registry Criteria would leverage this granularity by eliminating the disconnect between the Registry Criteria and the BES definition.

For GO/GOPs and TO/TOPs, it is proposed that registration be based on ownership/operation of BES generation or transmission assets, respectively. To achieve this result, the definitions of GO and GOP in Part II of the Registry Criteria will be revised to refer to ownership/operation of generating "Facilities" rather than the current generating "units"; no changes to the definitions of TO and TOP are needed, as they already refer to "Facilities." Looping the BES definition into the Part II definitions of these functions renders the Part III(c) and III(d) limitations on them redundant and, as discussed above, the existing Part III limitations are inconsistent with the new BES definition. These portions of Part III are thus proposed to be deleted.

As an example of how the revised Registry Criteria would interact with the new BES definition, if an entity owns and operates no transmission other than a 138 kV loop that either qualifies for one of the Exclusions in the BES definition or is excluded from the BES through the case-by-case BES exceptions process, the entity will no longer own or operate "transmission Facilities," and thus will not be subject to registration as a TO/TOP; if already registered, the entity can request that its TO and TOP registrations be deactivated.

Distribution Providers, which are currently registered if they have a peak load that meets the threshold specified in the Registry Criteria and are directly connected to the BPS, would instead be registered based on direct connection to the BES, determined by the result of application of the new BES definition and exception process. As discussed below, NERC also proposes to raise the DP size threshold from 25 MW to 75 MW. In other respects, the proposed revised Registry Criteria maintain the existing formulation ("Distribution system serving 25 MW [proposed to increase to 75 MW] of peak load that is directly connected to the BES"), which, according to NERC, requires a determination as to whether the entity's *system* is directly connected to the BES.[29]

B) Elimination of registrations that are commercial in nature

The RBR proposal would also eliminate registrations for three functions that are more commercial in nature, and do not substantially contribute to BES reliability: Interchange Authority (IA), Load-Serving Entity (LSE), and Purchasing-Selling Entity (PSE). These functions would be removed from the Registry Criteria and Rules of Procedure, and NERC would deactivate all IA, LSE, and PSE registrations upon implementation of RBR. Conforming changes would then be made to Reliability Standards and other NERC documents going forward as appropriate. This is expected to reduce burdens on registered entities, as well as on NERC and the Regional Entities, without posing a material risk to BPS reliability. For example, there are more than 400 registered Purchasing-Selling Entities, i.e. entities that purchase and sell energy and capacity. Of the four reliability standards applicable to PSEs, none imposes a responsibility that is not already borne by another function, generally the Balancing Authority. Of the few violations by IAs and PSEs, none has posed a serious risk to reliability;[30] and very few LSE violations have been discovered in recent years.[31]

[29] *See* August 2014 Phase - 1 Enhanced Draft Design Framework and Implementation Plan at 6. While FERC's decision in *SLECA*, appears consistent with that interpretation, some have continued to contend that only the peak load that is directly connected to the BES should be considered for purposes of assessing whether the peak load threshold, discussed below, is satisfied.

[30] NERC, Risk Based Registration Technical Justification (Aug. 26, 2014), at 4-5, 7, http://www.nerc.com/pa/comp/CAC/riskbasedregistrationdl/TechnicalReport_08262014_Final.pdf.

[31] *Id*. at 11.

C) Raising size threshold and reducing burden on small DPs

1. Increasing DP peak load threshold

Currently, a DP can be registered if it is directly connected to the BPS and has a peak load of more than 25 MW. The RBR proposal would raise that threshold to 75 MW (as well as replacing "Bulk Power System" with "BES"). Most of the other criteria for DP registration would be retained, however; DPs could be registered regardless of size or connection to the BES—as they can today—based on their control, ownership, or operation of Facilities that are part of a required BES-protective Under-Voltage Load Shedding program, a required Special Protection System, or a required transmission Protection System. In addition, to further protect reliability, a DP could be registered, again regardless of size or connection voltage, if it is responsible for providing services related to Nuclear Plant Interface Requirements pursuant to an executed agreement or has field switching personnel identified as performing unique tasks associated with the TOP's restoration plan that are outside of their normal tasks.

While NERC's draft technical report on this issue is not complete, it appears that the load represented by DPs under 75 MW is too small to have an impact on reliability, and that the current 25 MW threshold is far too low to provide reliability benefits justifying the burden. The RBR proposal would significantly reduce or eliminate compliance burdens for many small DPs that do not provide other important reliability services.

2. "UFLS-Only" DPs

The current Registry Criteria also call for registration of any DP, regardless of size, that participates in a required BES-protective Under-Frequency Load Shedding (UFLS) program.[32] Even DPs under 25 MW that participate in a required UFLS program must currently comply with *all* applicable DP (and LSE) reliability standards. The RBR proposal would remove that provision from the Registry Criteria; but would keep DPs that do not meet any of the remaining DP criteria, but participate in a required UFLS program, on the registry as "UFLS-Only DPs."[33] As proposed, UFLS-Only DPs would be responsible for complying with PRC-006, any applicable regional reliability standards whose purpose is to develop or establish a UFLS program, and any other reliability standards that identify UFLS-Only Distribution Providers in the applicability section, but *not* for any existing standard governing maintenance of UFLS protection systems (e.g., PRC-005), nor for any other standards applicable to a Distribution Provider.

[32] Current Registry Criteria, Section III.b.2.

[33] Draft Registry Criteria, Section III(b).

The concept behind this proposal is that DPs that currently participate in UFLS programs should continue to do so; but that the risk posed by not requiring such entities to perform and document maintenance and testing on a set schedule is miniscule (as indicated by NERC's technical studies thus far), and does not warrant imposing the burden of such requirements on these entities. There is not a current proposal to revise the Functional Model or the NERC Glossary to add UFLS-Only DPs as a separate functional entity; instead, NERC is treating them as DPs whose compliance obligations are limited to a specified sub-set list of reliability standards identified in the Registry Criteria.

D) Procedural improvements

The RBR proposal includes changes to NERC's Rules of Procedure to clarify and improve the procedures related to registration.[34] RBR would add a specified process with deadlines for deactivation (i.e. removal from the registry for a particular function). In addition, taking a cue from the BES definition's use of both bright lines and a case-by-case exception process, the RBR proposal includes a non-exclusive list of materiality factors that may be used by the Regional Entity to register an entity that otherwise does not meet the bright lines in the Registry Criteria, and by an entity to show that it should not be registered despite meeting the bright line Registry Criteria. To drive greater consistency among regions, such materiality questions, as well as disputes regarding the application of thresholds, are to be reviewed by a NERC-led panel with multi-regional representation. The existing appeals process would be available following any decision by the NERC-led panel.

While, as discussed below, consideration of limitations on standards and requirements applicable to lower-risk TO/TOPs and GO/GOPs has been postponed to a second phase of the RBR initiative, Phase I of RBR does include several procedural improvements related to such limitations. First, procedures are proposed for entities, at any time, to request that they be subject only to a "sub-set list" of otherwise-applicable standards, on a case-by-case basis.[35] Second, the proposed revised procedures make clear that entities that qualify as UFLS-Only DPs can be moved to that status by their Regional Entities, without need for a more involved process unless the Regional Entity disagrees with the registered entity. Third, the RBR proposal eases the burden on a registered entity to attest at every compliance contact that a requirement is not

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[34] *See* NERC, Appendix 5A, Organization Registration and Certification Manual, August 26, 2014 Draft, http://www.nerc.com/pa/comp/CAC/riskbasedregistrationdl/Revised_August%20262014_Appendix_5A_OrganizationRegistration_Final_posted.pdf.

[35] NERC has always had discretion to limit entities' compliance obligations in this way; *see, e.g.*, *Cedar Creek Wind Energy, LLC, et al.*, 139 FERC ¶ 61,214 (2012). Clear procedures may allow more entities to request and receive such treatment and will help ensure consistent treatment of such entities.

applicable (e.g., because the entity does not own the relevant equipment) by allowing the entity to make a one-time attestation, subject to revision if the underlying facts change.

CHALLENGES

A) NERC and FERC approval

Because RBR involves changes to NERC's Rules of Procedure, it is not subject to a stakeholder vote, but stakeholder comments must be solicited and considered by the NERC Board. If the Board approves the proposal, it must then be filed with and approved by FERC. The technical justification must thus be sufficient to support NERC Board and FERC approval—not a low bar. The completed technical evaluation will be presented to the NERC Board in November, and included in the FERC filing. Industry support for NERC's proposal will be key to success at that stage.

B) Key elements moved to Phase II

One element proposed as part of RBR has been postponed to a Phase II to allow more time for technical analysis. One impetus for the RBR initiative was that there are entities registered as TO and TOP whose BES transmission is limited, and insufficient to give them the wide-area view on which many TO and TOP standards are predicted. A similar situation may exist with respect to small GO/GOPs whose generators rarely operate. While such entities may pose sufficient risk to BES reliability to warrant continued registration, they should be subject to fewer standards than entities that have a more significant impact on BES reliability. The concept is to limit compliance obligations for a clearly defined set of lower-risk entities to a specific list of standards and requirements that would be identified on a qualifying entity's listing on the Compliance Registry. The intent would be to reduce unnecessary compliance burdens on those entities and on NERC and the Regional Entities, while preserving compliance obligations needed for reliability and providing regulatory certainty.

This approach holds great promise to reduce the disproportionate burdens imposed on lower-risk entities that own or operate limited BES Facilities. For example, it does not make sense to apply the hundreds of TOP requirements to an entity that owns only a single short 138 kV BES line segment, and has no wide-area view of the transmission system. It does make sense to require compliance with a more limited set of requirements that are within the small TOP's span of control. And there is precedent for this approach: the "GO/TO project," approved by FERC, subjects GOs that own and operate transmission only in the form of limited generator interconnection facilities to a small subset of TO and TOP standards, rather than registering them as full TO/TOPs.[36]

As a result of technical issues, this part of the RBR proposal could not be adequately prepared for FERC filing on the same ambitious timeline as the other portions of RBR. While the identification and treatment of low-risk TO/TOPs and GO/GOPs will be handled in Phase II of the RBR initiative, the groundwork is starting to be developed through technical conferences. However, it remains to be seen whether the RBR initiative can maintain its momentum through this second phase to live up to its full potential.

CONCLUSION

The RBR effort shows real promise to reduce unnecessary burdens on NERC, the Regional Entities, and registered entities, while advancing reliability by focusing resources where it counts. However, significant steps remain to see it through to NERC and FERC approval and implementation.

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[36] Generator Requirements at the Transmission Interface, Order No. 785, 144 FERC ¶ 61,221 (2013).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5B

Statement of Compliance Registry Criteria

Revision 5.2~~1~~

Effective: DATE~~July 1, 2014~~

Statement of Compliance Registry Criteria (Revision 5.2~~1~~)

Summary

~~Since becoming the Electric Reliability Organization (ERO), NERC has initiated a program to identify candidate organizations for its Compliance Registry. The program, conducted by NERC and the Regional Entities[1], will also confirm the functions and information now on file for currently-registered organizations.~~ This document describes how NERC will identify organizations that may be candidates for Registration and assign them to the Compliance Registry.

NERC and the Regional Entities[2] have the obligation to identify and register all entities that meet the criteria for inclusion in the Compliance Registry, as further explained in the balance of this document.

Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System (BPS), perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected ~~Bulk Power System~~BPS as defined by the criteria and notes set forth in this document. NERC will apply the following principles to the Compliance Registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the ~~Bulk Power System~~BPS who have a material impact[3] on the ~~Bulk Power System~~BPS through a Compliance Registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material reliability impact on the ~~Bulk Power System~~BPS in order to develop a complete and current Compliance Registry list. The Compliance Registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the Compliance Registry are responsible and will be monitored for compliance with applicable mandatory Reliability Standards. They will be subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.
- NERC and Regional Entities will not monitor nor hold those not in the Compliance Registry responsible for compliance with the Reliability Standards. An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material reliability impact, will be added to the Compliance Registry. Such entity will not be subject to a sanction or Penalty by NERC or the Regional Entity for actions or inactions prior to being placed on the Compliance Registry, but may be required to comply with a Remedial Action Directive or Mitigation Plan in order to become compliant with applicable Reliability Standards. After such entity has been placed on the Compliance Registry, it shall be responsible for complying with Reliability Standards and may be subject to sanctions or Penalties as well as any Remedial Action Directives and Mitigation Plans required by the Regional Entities or NERC for future violations, including any failure to follow a Remedial Action Directive or Mitigation Plan to become compliant with Reliability Standards.

~~[1] The term "Regional Entities" includes Cross-Border Regional Entities.~~

[2] The term "Regional Entities" includes Cross-Border Regional Entities.

[3] The criteria for determining whether an entity will be placed on the Compliance Registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the Director of Compliance that an organization be added to or removed from the Compliance Registry, pursuant to NERC Rules of ~~O~~Procedure Section 501.1.3.5.

- Required compliance by a given organization with the Reliability Standards will begin the later of (i) inclusion of that organization in the Compliance Registry and (ii) approval by the Applicable Governmental Authority of mandatory Reliability Standards applicable to the r~~R~~egistered e~~E~~ntity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC. Presence on or absence from the Compliance Registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

Background

In 2005, NERC and the Regional Entities conducted a voluntary organization registration program limited to Balancing Authorities, Planning Authorities, regional reliability organizations, Reliability Coordinators, Transmission Operators, and Transmission Planners. The list of the entities that were registered constitutes what NERC considered at that time as its Compliance Registry.

NERC ~~has recently~~ initiated a broader program to identify additional organizations potentially eligible to be included in the Compliance Registry and to confirm the information of organizations currently on file, taking into account the following considerations~~. NERC believes this is a prudent activity at this time because~~:

- As of July 20, 2006, NERC was certified as the electric reliability organization (ERO) created for the U.S. by the Energy Policy Act of 2005 (EPAct) and FERC Order No. 672. NERC has received similar recognition by~~has also filed with~~ Canadian authorities ~~for similar recognition~~ in their respective jurisdictions.
- FERC~~'s~~ Order No. 672 directs that owners, operators and users of the ~~Bulk Power System~~BPS in the U.S. shall be registered with the ERO and the appropriate Regional Entities.
- As the ERO, NERC has filed its current Reliability Standards with FERC and with Canadian authorities. A~~s~~s accepted and approved by FERC and appropriate Canadian authorities, the Reliability Standards are no longer voluntary, and organizations that do not fully comply with them may face Penalties or other sanctions, in accordance with applicable laws, regulations and orders of Applicable Governmental Authorities. ~~determined and levied by NERC or the Regional Entities.~~
- NERC's Reliability Standards include compliance Requirements for additional reliability function types beyond the six types registered by earlier registration programs.
- Based on selection as the ERO, ~~the extension and expansion of~~ NERC's ~~current~~ Organization Registration program[4][5] is the means by which NERC and the Regional Entities ~~will~~ plan, manage and execute Reliability Standard compliance oversight of owners, operators, and users of the ~~Bulk Power System~~BPS.
- Organizations listed in the Compliance Registry are subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.

Statement of Issue

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[4] ~~See: NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.~~

[5] *See*~~:~~ NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its Compliance Registry each entity that NERC concludes can materially impact the reliability of the ~~Bulk Power System~~BPS. ~~However, the potential costs and effort of ensuring that every organization potentially within the scope of "owner, operator, and user of the Bulk Power System" becomes registered while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.~~

NERC wishes to identify ~~as many organizations as possible~~ those entities that may need to be listed in its Compliance Registry. Identifying these organizations is necessary and prudent ~~at this time~~ for the purpose of determining resource needs, both at the NERC and Regional Entity level, and for~~to~~ ~~begin the process of~~ communicating~~ion~~ with these entities regarding their potential responsibilities and obligations. NERC and the Regional Entities believe that ~~primary~~ candidate entities can be identified at any time ~~at this time, while other entities can be identified later~~, as and when needed. ~~Selection principles and criteria for the identification of these initial entities are required. This list will become the "Initial Non-binding Organization Registration List". With FERC having made the approved Reliability Standards enforceable, this list becomes the NERC Compliance Registry~~The Compliance Registry is available on NERC's website.

Resolution

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between Regions and across the continent with respect to which entities are registered~~,~~; and~~;~~
2. Any entity reasonably deemed material to the reliability of the ~~Bulk Power System~~BPS will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the Bulk Electric~~Power~~ System (BES).

In order to promote consistency, NERC and the Regional Entities ~~intend to~~ use the following criteria as the basis for determining whether particular entities should be identified as candidates for Registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following four groups of criteria (Sections I-IV) plus the statements in Section V will provide guidance regarding an entity's Registration status:

- Section I determines if the entity is an owner, operator, or user of the ~~Bulk Power System~~BPS and, hence, a candidate for organization Registration.
- Section II uses NERC's current functional type definitions to provide an initial determination of the functional types for which the entities identified in Section I should be considered for Registration.

- Section III lists the criteria regarding smaller entities; these criteria can be used to forego the Registration of entities that were selected to be considered for Registration pursuant to Sections I and II and, if circumstances change, for later removing entities from the Compliance Registry~~Registration list~~ that no longer meet the relevant criteria.
- Section IV — additional criteria for joint Registration. Joint Registration criteria may be used by joint action agencies, generation and transmission cooperatives and other entities which agree upon a clear division of compliance responsibility for Reliability Standards by written agreement. ~~Pursuant to FERC's directive in paragraph 107 of Order No. 693, r~~Rules pertaining to joint Registration and Joint Registration Organizations, as well as Coordinated Functional Registrations, ~~will~~ are now ~~be~~ found in Sections 501, ~~and~~ 507 and 508 of the NERC Rules of Procedure.

I. Entities that use, own or operate Elements of the ~~Bulk Electric System~~BES as established by NERC's approved definition of ~~Bulk Electric System~~BES below are (i) owners, operators, and users of the ~~Bulk Power System~~BPS and (ii) candidates for Registration:

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- ***I1*** *- Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.*
- ***I2*** *- Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:*
  - *a) Gross individual nameplate rating greater than 20 MVA. Or,*
  - *b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.*
- ***I3*** *- Blackstart Resources identified in the Transmission Operator's restoration plan.*
- ***I4*** *- Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:*
  - *a) The individual resources, and*
  - *b) The system designed primarily for delivering capacity from the point where those resources aggregate to a greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.*
- ***I5*** *- Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.*

Exclusions:

- ***E1*** *- Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*
  - *a) Only serves Load. Or,*
  - *b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
  - *c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

  Note 2 – The presence of a contiguous loop operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- ***E2*** *- A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.*

- ***E3*** *- Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:*
  - *a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);*
  - *b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and*
  - *c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).*

- ***E4*** *- Reactive Power devices installed for the sole benefit of a retail customer(s).*

  Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

II. Entities identified in Part I above will be categorized as Registration candidates who may be subject to Registration under one or more appropriate Functional Entity types based on a comparison of the functions the entity normally performs against the following function type definitions:[6]

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. Note: As provided in Section III.b.1 and Note 5 below, a Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider.
Generator Operator	GOP	The entity that operates generating ~~unit(s)~~Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	Entity that owns and maintains generating ~~units~~Facility(ies).
~~Interchange Authority~~	~~IA~~	~~The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.~~
~~Load-Serving Entity~~	~~LSE~~	~~Secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.~~

[6] Exclusion: An entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, including bilateral agreements and Sections 501, 507 and 508 of the NERC Rules of Procedure.

Function Type	Acronym	Definition/Discussion
Planning Authority/ Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
~~Purchasing-Selling Entity~~	~~PSE~~	~~The entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. PSE may be affiliated or unaffiliated merchants and may or may not own generating Facilities.~~
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the B~~ulk~~ E~~lectric~~ S~~ystem~~, has the Wide Area view of the B~~ulk~~ E~~lectric~~ S~~ystem~~, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.

Function Type	Acronym	Definition/Discussion
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

~~II.~~III. Except as provided in Section V and the Notes to the Criteria below, e~~E~~ntities identified in Part II above as being subject to Registration as a~~n LSE,~~ Distribution Provider~~, GO, GOP, TO, or TOP~~ should be included ~~excluded from~~ in the Compliance Registry for these functions only if they ~~do not~~ meet any of the criteria listed below:

~~III (a) Load-Serving Entity:~~

~~II.a.1 Load-Serving Entity peak Load is > 25 MW and is directly connected to the Bulk Power (>100 kV) System, or;~~

~~II.a.2 Load-Serving Entity is designated as the responsible entity for Facilities that are part of a required underfrequency Load shedding (UFLS) program designed, installed, and operated for the protection of the Bulk Power System, or;~~

~~II.a.3 Load-Serving Entity is designated as the responsible entity for Facilities that are part of a required undervoltage Load shedding (UVLS) program designed, installed, and operated for the protection of the Bulk Power System.~~

~~*[Exclusion: A Load-Serving Entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, Balancing Authority, Transmission Operator, generation and transmission cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~

~~II.a.4 Distribution Providers registered under the criteria in III.b.1 or III.b.2 will be registered as a Load Serving Entity (LSE) for all Load directly connected to their distribution facilities.~~

~~*[Exclusion: A Distribution Provider will not be registered based on this criterion if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, Balancing Authority, Transmission Operator, generation and transmission cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~

~~II(b)~~III(a) Distribution Provider:

~~II.b.1~~III.a.1 Distribution Provider system serving >~~25~~75 MW of peak Load that is directly connected to the ~~Bulk Power System~~BES;[7] or

~~*[Exclusion: A Distribution Provider will not be registered based on this criterion if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, Balancing Authority, Transmission Operator, generation and transmission cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~ ~~or;~~

~~II.b.2~~III.a.2 -Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:[8]

- ~~a required UFLS program.~~
- a required ~~UVLS program~~Undervoltage Load Shedding (UVLS) program and/or~~.~~
- a required Special Protection System and/or~~.~~
- a required transmission Protection System; or~~.~~

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.

~~*[Exclusion: A Distribution Provider will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Balancing Authority, Transmission Operator, generation and transmission cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~~~;~~

III(b) Distribution Provider with UFLS-Only assets (referred to as "UFLS-Only Distribution Provider")

III.b.1 UFLS-Only Distribution Provider does not meet any of the other registration criteria in Sections III(a)(1)-(4) for a Distribution Provider; and

III.b.2 UFLS-Only Distribution Provider is the responsible entity that owns, controls, or operates UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES.

[7] Ownership, control or operation of UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES does not affect an entity's eligibility for registration pursuant to III.a.1.

[8] As used in Section III.a.2, "protection of the Bulk Electric System" means protection to prevent instability, Cascading, or uncontrolled separation of the BES and not for local voltage issues (UVLS) or local line loading management (Special Protection System) that are demonstrated to be contained within a local area.

A UFLS-Only Distribution Provider shall be listed in the Compliance Registry as responsible for complying with PRC-006-1 and any Regional Reliability Standard(s) whose purpose is to develop or establish a UFLS Program (excluding any then-existing Standard whose purpose is maintaining Protection Systems used for underfrequency load-shedding systems) in effect as of November 1, 2014, as well as any other Reliability Standards that identify UFLS-Only Distribution Providers in their applicability section, but not the other standards applicable to a Distribution Provider.

~~II(c) Generator Owner/Operator:~~

~~II.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the Bulk Power System, or;~~

~~II.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the Bulk Power System at a common bus with total generation above 75 MVA gross nameplate rating, or;~~

~~II.c.3 Any generator, regardless of size, that is a Blackstart Resource material to and designated as part of a Transmission Operator entity's restoration plan, or;~~

~~II.c.4 Any generator, regardless of size, that is material to the reliability of the Bulk Power System.~~

~~*[Exclusions:*~~

~~*A Generator Owner/Operator will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, generation and transmission cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.*~~

~~*As a general matter, a customer-owned or operated generator/generation that serves all or part of retail Load with electric energy on the customer's side of the retail meter may be excluded as a candidate for Registration based on these criteria if (i) the net capacity provided to the Bulk Power System does not exceed the criteria above or the Regional Entity otherwise determines the generator is not material to the Bulk Power System and (ii) standby, back-up and maintenance power services are provided to the generator or to the retail Load pursuant to a binding obligation with another Generator Owner/Operator or under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable.]*~~

~~II(d) Transmission Owner/Operator:~~

~~II.d.1 An entity that owns/operates an integrated transmission Element associated with the Bulk Power System 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the Reliable Operation of the interconnected transmission grid; or~~

~~II.d.2 An entity that owns/operates a transmission Element below 100 kV associated with a Facility that is included on a critical Facilities list that is defined by the Regional Entity.~~

~~[Exclusion: A Transmission Owner/Operator will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, generation and transmission cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.~~

~~III.~~IV. Joint Registration Organization, Coordinated Functional Registration and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint Registrations and Joint Registration Organizations, as well as Coordinated Functional Registrations, are now found in Section 501, ~~and~~ 507 and 508 of the NERC Rules of Procedure.

~~IV.~~V. If NERC or a Regional Entity encounters an organization that is not listed in the Compliance Registry, but which should be subject to the Reliability Standards, NERC or the Regional Entity is obligated and will initiate actions to add that organization to the Compliance Registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure and as described in Note 3 below.

Notes to the above Criteria

1. The above are general criteria only. The Regional Entity considering Registration of an organization not meeting (e.g., smaller in size than) the criteria may propose Registration of that organization if the Regional Entity believes and can reasonably demonstrate[9] that the organization is a ~~Bulk Power System~~BES owner, or operates, or uses ~~Bulk Power System~~BES assets, and is material to the reliability of the ~~Bulk Power System~~BES. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for Registration if it believes and can reasonably demonstrate to NERC that the ~~Bulk Power System~~BES owner, operator, or user does not have a material impact on the reliability of the ~~Bulk Power System~~BES. Such decisions must be made in accordance with Section V of Appendix 5A to the NERC Rules of Procedure. In order to ensure a consistent approach to assessing materiality, a non-exclusive set of factors ("materiality test") for consideration is identified below; however, only a sub-set of these factors may be applicable to particular functional registration categories:

   a. Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?

[9] The reasonableness of any such demonstration will be subject to review and remand by NERC itself, or by any Applicable Governmental Authority, as applicable.

b. Will intentional or inadvertent removal of an Element owned or operated by the entity, or a common mode failure of two Elements as identified in the Reliability Standards (for example, loss of two Elements as a result of a breaker failure), lead to a Reliability Standards issue on another system (such as a neighboring entity's Element exceeding an applicable rating, or loss of non-consequential load due to a single contingency). Conversely, will such contingencies on a neighboring entity's system result in Reliability Standards issues on the system of the entity in question?

c. Can the normal operation, Misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?

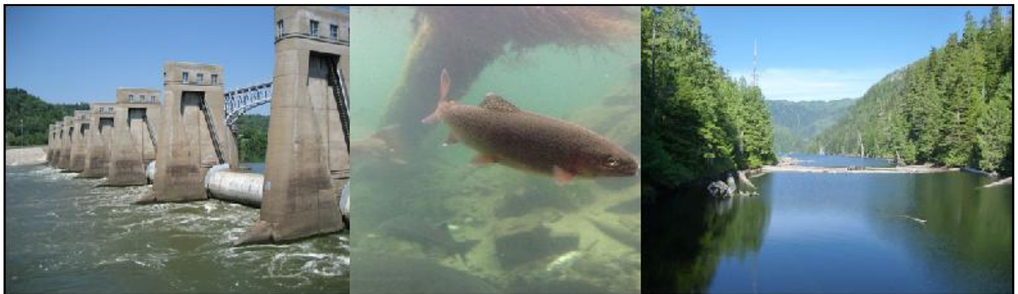
d. Can the normal operation, Misoperation or malicious use of the entity's Protective Systems (including UFLS, UVLS, Special Protection System and other Protective Systems protecting BES Facilities) cause a detrimental adverse impact on the operational reliability of any associated Balancing Authority, Generator Operator or Transmission Operator, or the automatic load shedding programs of a PC or TP (UFLS, UVLS)?

2. An organization not identified using the criteria, but wishing to be registered, may request that it be registered. For further information refer to: NERC Rules of Procedure, Section 500 – Organization Registration and Certification; Part 1.3.

3. An organization may challenge its Registration within the Compliance Registry. NERC or the Regional Entity will provide the organization with all information necessary to timely challenge that determination including notice of the deadline for contesting the determination and the relevant procedures to be followed as described in the NERC Rules of Procedure; Section 500 – Organization Registration and Certification.

4. If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the ~~Bulk Power System~~BES, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable Reliability Standards and Requirements irrespective of other considerations, in accordance with laws, regulations and orders of an Applicable Governmental Authority.

5. NERC may limit the compliance obligations of a given entity registered for a particular function or similarly situated class of entities, as warranted based on the particular facts and circumstances, to a sub-set list of Reliability Standards (which may specify Requirements/sub-Requirements).



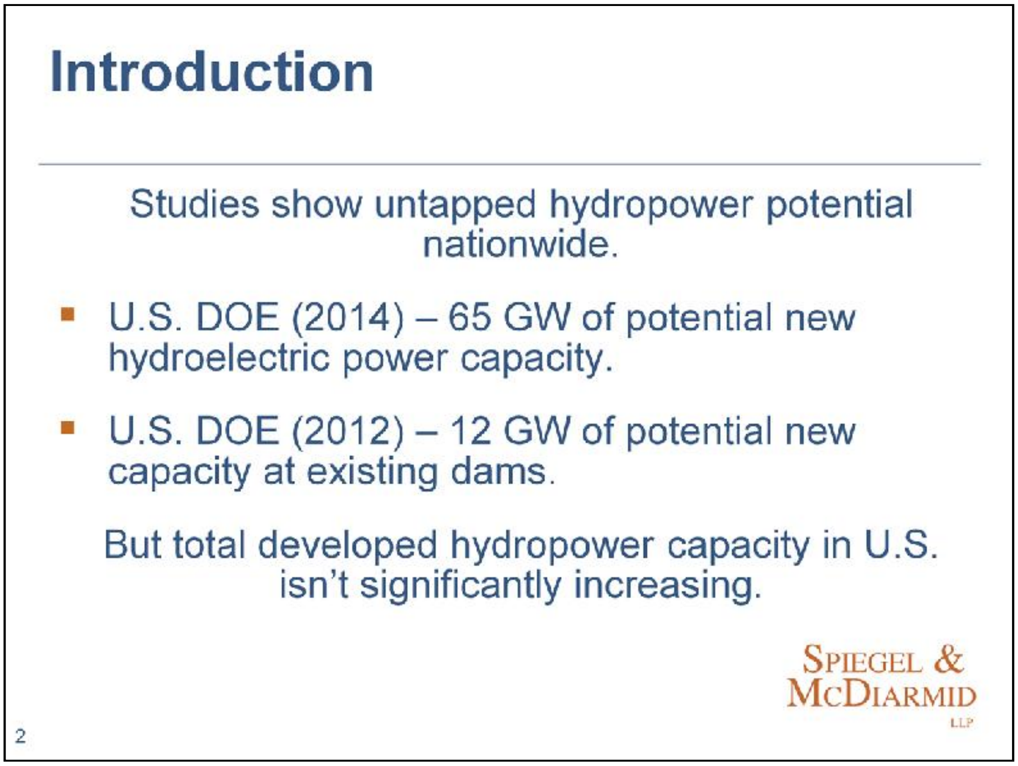
Swimming Against the Current:
Making the FERC Hydroelectric Process Work For You

William Huang and Katie Mapes

APPA Legal Seminar

October 20, 2014

SPIEGEL & McDIARMID LLP



Citations:

1. U.S. DOE, *New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States* (April 2014), http://nhapp.ornl.gov/sites/default/filesORNL_NSD_FY14_Final_Report.pdf. Concludes that the U.S. has up to 65 GW of new hydroelectric power capacity.
2. U.S. DOE, *An Assessment of Energy Potential at Non-Powered Dams in the United States* (April 2012), http://nhaap.ornl.gov/system/files/NHAAP_NPD_FY11_Final _Report.pdf. Concludes that the U.S. has up to 12 GW of new hydroelectric power capacity that could be built at existing dams.
3. Idaho National Engineering and Environmental Laboratory ("INEEL") has published studies in 2003, 2004, and 2006 that also concluded that there is substantial untapped hydropower potential in the United States, including at existing dams and irrigation facilities. INEEL, *Estimation of Economic Parameters of U.S. Hydropower Resources* (June 2003), http://hydropower.inel.gov/resourceassessment/pdfs/project_report-final_with_disclaimer-3jul03.pdf; INEEL, Water Energy Resources of the United States with Emphasis on Low Head/Low Power Resources (April 2004), http://hydropower.inel.gov/resourceassessment/pdfs/03-11111.pdf; INEEL, Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants (Jan. 2006), http://hydropower.inel.gov/resourceassessment/pdfs/main_report_appendix_a_final.pdf.

Introduction

Four Scenarios

1. A preliminary permit next door.
2. Your project is up for relicense.
3. Someone else's project is up for relicense.
4. You want to develop a project.

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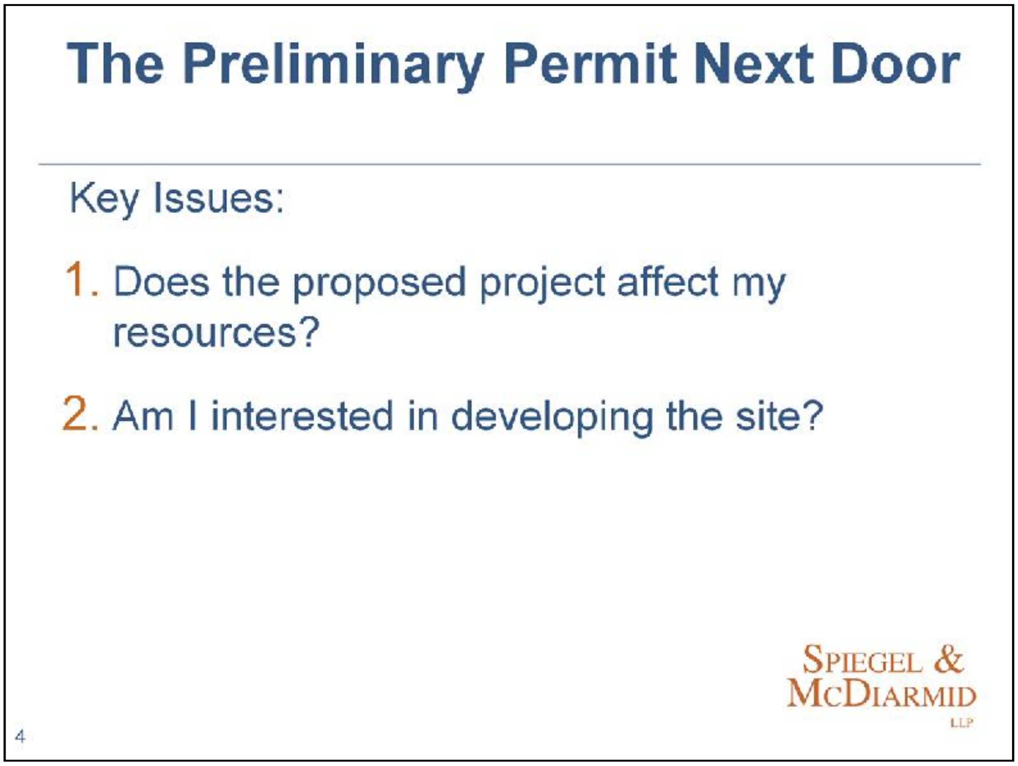


4. Notification Rules: FPA § 4(f), 16 U.S.C. § 797. Individualized notice sent to "[a]ny state or municipality likely to be interested in or affected by such application." The Commission will notice a date for all interventions, protests, and competing applications. 18 C.F.R. § 4.36.

5. See Owyhee Hydro, LLC, 136 FERC ¶ 62,189, P 10 (2011); FPA § 6, 16 U.S.C. § 799 ("Licenses may be revoked only for the reasons and in the manner prescribed under the provisions of this chapter, and may be altered or surrendered only upon mutual agreement between the licensee and the Commission after thirty days' public notice.").

6. Contents of Application: 18 C.F.R. § 4.81.

8. Rules of Priority: 18 C.F.R. § 4.37.

9. Best Adapted: *City of Ukiah, Cal.*, 18 FERC ¶ 61,108, at 61,203 (*quoting* 16 U.S.C. § 800(a)), *on reh'g*, 21 FERC ¶ 61,133 (1982), *on reh'g*, 22 FERC ¶ 61,063, *amended*, 24 FERC ¶ 61,140 (1983), *aff'd*, 729 F.2d 793 (D.C. Cir. 1984); *Marsh Island Hydro Assocs.*, 16 FERC ¶ 61,236 (1981).

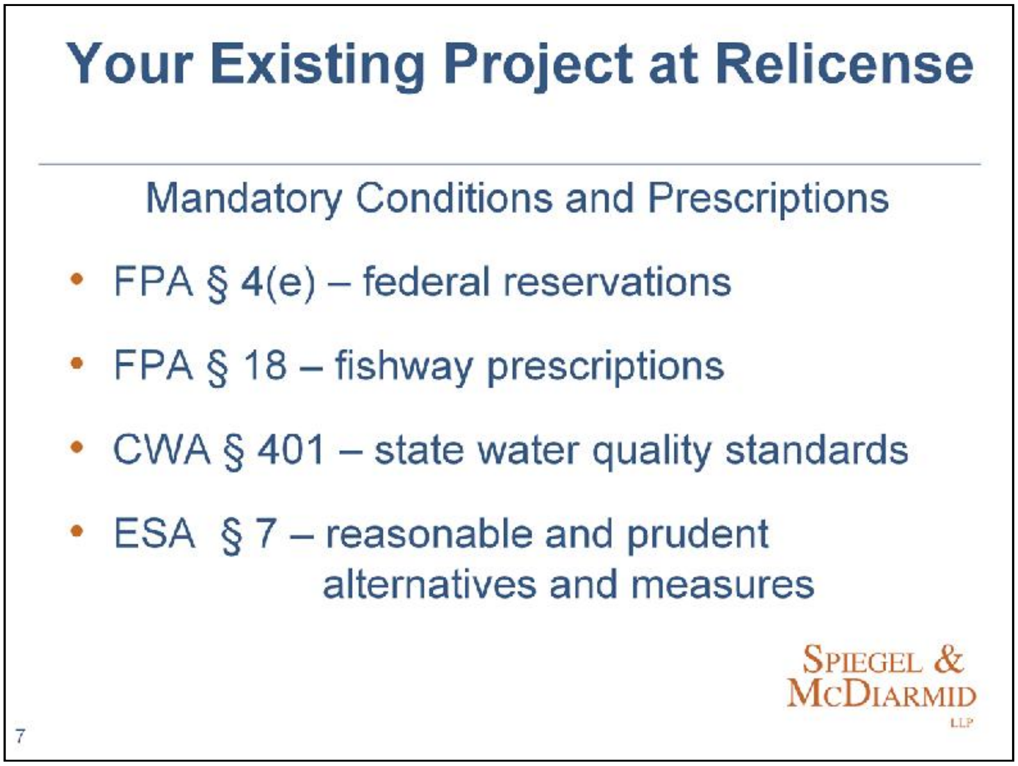
10. Municipal Preference: FPA § 7(a), 16 U.S.C. § 800(a).

11. First-filed Applicant: 18 C.F.R. § 4.37(a)(b)(2).

12. FERC drawings: *see*, *e.g.*, *FFP Qualified Hydro 14, LLC*, 145 FERC ¶ 61,255, P 20 (2013).

13. 16 U.S.C. § 803. (“That the project adopted, including the maps, plans, and specifications, shall be such as in the judgment of the Commission will be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, for the adequate protection, mitigation, and enhancement of fish and wildlife (including related spawning grounds and habitat), and for other beneficial public uses, including irrigation, flood control, water supply, and recreational and other purposes referred to in section 797(e) of this title.”); 16 U.S.C. § 808(a)(2) (“Any new license issued under this section shall be issued to the applicant having the final proposal which the Commission determines is best adapted to serve the public interest …”). *See also* 16 U.S.C. § 797(e).

14. Integrated Licensing Process regulations: 18 C.F.R. §§ 5.1-5.31.



15. 16 U.S.C. § 797(e); 16 U.S.C. § 811; 33 U. S. C. § 1341; 16 U. S. C. § 1536.

16. EPAct 2005 Hearings: FPA § 33, 16 U.S.C. § 823d; Energy Policy Act of 2005 (EPAct 2005), Pub. L. No. 109-58, 119 Stat. 594, 42 U.S.C. § § 15801 *et seq*.

17. EPAct 2005 Hearing Regulations: U.S. Department of Agriculture, U.S. Department of the Interior, and U.S. Department of Commerce. Resource Agency Procedures for Conditions and Prescriptions in Hydropower Licenses, 70 Fed. Reg. 69,804 (Nov. 17, 2005). The Forest Service's regulations are found at 7 C.F.R. § 1.601 *et seq*.; the National Marine Fisheries Service regulations are found at 50 C.F.R. § 221 *et seq*.; and the U.S. Fish and Wildlife Service regulations are found at 43 C.F.R. § 45.1 *et seq*.

18. 16 U.S.C. § 803(a)(1) (identifying water supply as a beneficial public use included in FERC's "best adapted" determination). *See also Appalachian Power Co.*, 66 FERC ¶ 61,316, at 61,955 (1994) (including articles requiring a "project operating plan that gives priority to Lynchburg's water needs during emergency drawdowns of the project reservoir" and "one year's notice to Lynchburg of Appalachian's intent to surrender the project license."); *City of Portland*, 6 FERC ¶ 61,257, at 61,629 (1979) (ordering a licensee to operate its reservoirs "in whatever manner is necessary . . . to assure sufficient quality and quantity at all times for the City of Portland's water supply.")

19. Office of Energy Projects, FERC, *Guidance for Shoreline Management Planning at Hydropower Projects*, July 2012, http://www.ferc.gov/industries/hydropower/gen-info/guidelines/smpbook.pdf. *See, e.g.*, *Appalachian Power Co.*, 146 FERC ¶ 62,083 (2014) (approving a Shoreline Management Plan that zones the shoreline of the project reservoirs of the Smith Mountain Pumped Storage Project).

20. Competitive License Applications: 16 U.S.C. § 808(a)(2); *Pub. Util. Dist. No. 2 of Grant Cnty., Wash.*, 92 FERC ¶ 61,042; *Holyoke Water Power Co.*, 88 FERC ¶ 61,186 (1999); *N.E.W. Hydro, Inc.*, 81 FERC ¶ 61,238 (1997); *FirstLight Hydro Generating Co.* 145 FERC ¶ 61,157 (2013).

Developing a New Project

- Is your project completely exempt from FERC licensing?
  - Qualifying Conduit Hydropower Facility
- If not, what should I ask FERC for?
  - Preliminary Permit
  - License versus Exemption
- If a license, which process?

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9

Developing a New Project

- Qualifying Conduit Hydropower Facility
  - Built on a non-federal conduit ("manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity")
  - 5 MW or less
  - Not already under a license or exemption

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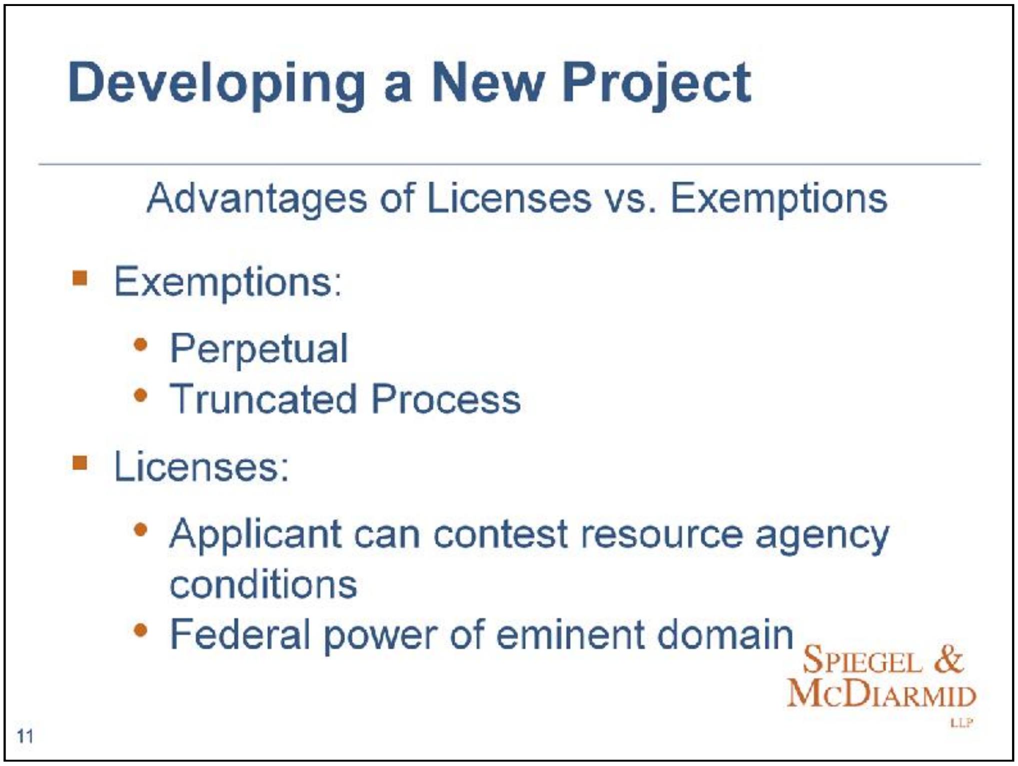
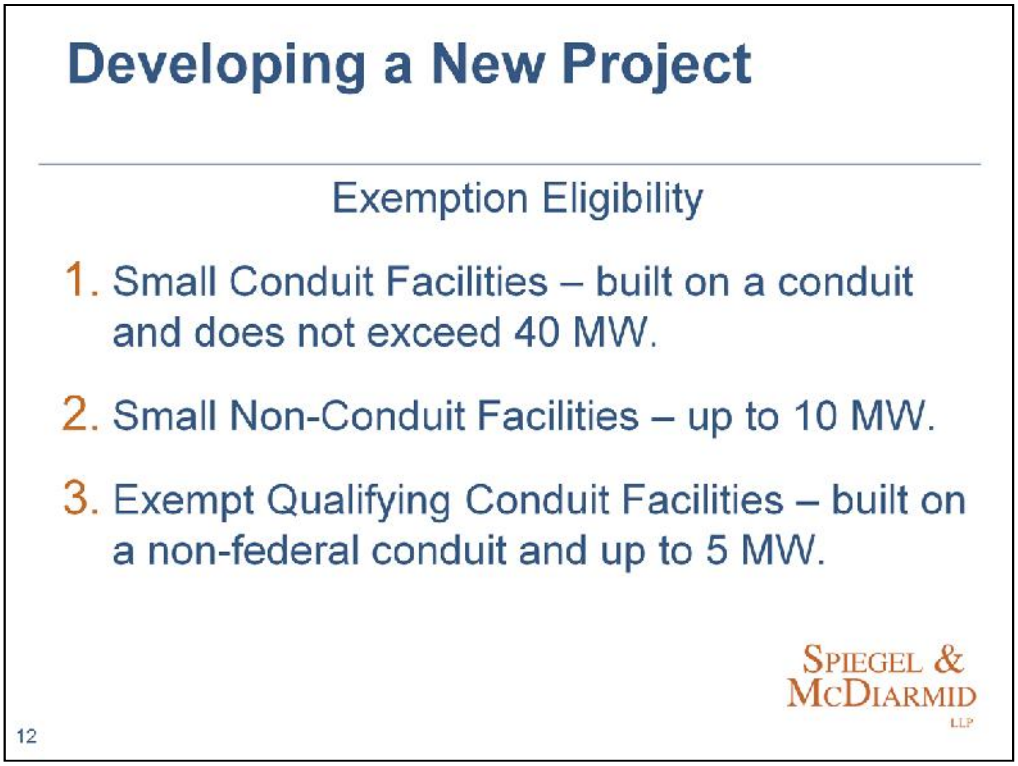


21. Exemption regulations: 18 C.F.R. §§4.92-4.95.

22. Federal Power of Eminent Domain: FPA §21, 16 U.S.C. §814.



23. Small Conduit Hydroelectric Facility: defined in 18 C.F.R. § 4.30(b)(28).

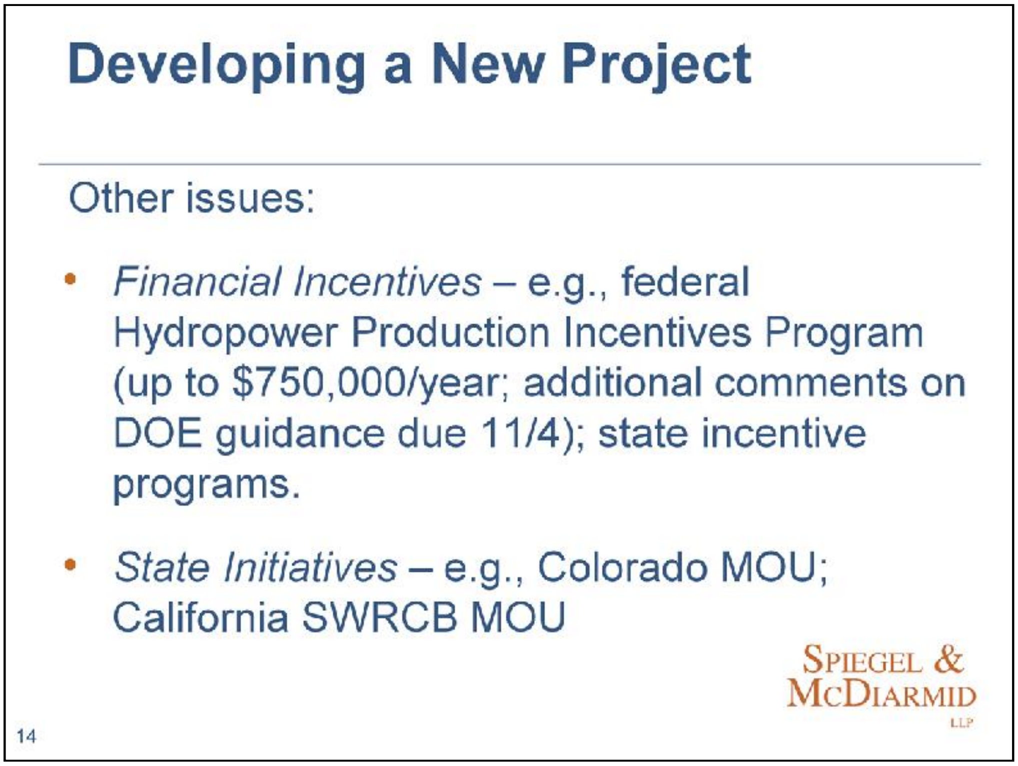
24. Statutory Provisions on Exemption: 16 U.S.C. § 823a.

25. Hydropower Regulatory Efficiency Act of 2013, Pub. L. No. 113-23, 127 Stat. 493, http://www.gpo.gov/fdsys/pkg/PLAW-113publ23/pdf/PLAW-113publ23.pdf.

26. ILP Regulations: 18 C.F.R. §§5.1-5.31.

27. Permission to use TLP or alternative processes: 18 C.F.R. §5.8.

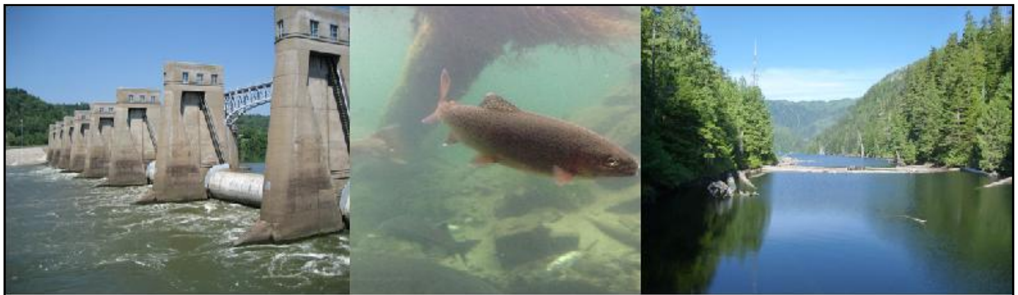
28. FERC, *FERC Approves Pilot Project to Test Two-Year Hydropower Licensing Process* (Aug. 2014), eLibrary No. 20140805-3059.



29. Hydropower Production Incentives Program: Energy Policy Act of 2005, § 242, codified at 42 U.S.C. § 15881; for descriptions of selected state incentive programs, *see* Database of State Incentives for Renewables and Efficiency, http://dsireusa.org/.

30. *Memorandum of Understanding between FERC and the State of Colorado through the Governor's Energy Office to Streamline and Simplify the Authorization of Small Scale Hydropower Projects* (Aug. 2010), http://www.ferc.gov/legal/mou/mou-co.pdf.

31. *Memorandum of Understanding between FERC and the California State Water Resources Control Board Concerning Coordination of Pre-Application Activities for Non-Federal Hydropower Proposals in California* (Nov. 2013), http://www.ferc.gov/legal/mou/mou-caswb-11-2013.pdf.



QUESTIONS?

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