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FEDERAL AND STATE REGULATORY UPDATE

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Federal Matters

1. Federal Courts

A. United States Court of Appeals for the District of Columbia Circuit

1. *Calpine Corp. v. FERC (D.C. Cir. December 18, 2012)*

On December 18, 2012, the DC Circuit upheld a Federal Energy Regulatory Commission (FERC) determination that FERC lacks jurisdiction over independent generators' use of "station power"—the electric energy used for the heating, lighting, air conditioning, and office equipment needs of buildings on a generating facility's site and for operating the electrical equipment on the site.

The most recent decision originally started with FERC ruling on a complaint based on the provisions of the California Independent System Operator's (CAISO) station power protocol. In June 2005, FERC determined (i) that a transmission provider's supply of station power did not constitute a retail sale but instead was a wholesale sale; and (ii) that the provision of station power is subject to FERC jurisdiction if, after subtracting its station power from its overall power, a generator is "net positive". On appeal, the DC Circuit vacated FERC's order and determined that FERC had wrongly intruded on a matter of state regulation. On remand, FERC acknowledged that it lacked a jurisdictional basis to determine when the provision of station power constituted a retail sale. FERC clarified, however, that it was free to order the use of a different netting interval to determine the amount of station power transmitted in interstate commerce than the netting period selected by the state to assess retail charges. Calpine Corporation and other California generators petitioned for judicial review of FERC's order on remand, arguing that the order discriminated against independent generators by forcing them to pay a retail charge for their own station power whereas the integrated utilities would avoid paying similar charges by simply taking station power from their own generators.

In the instant appeal, the DC Circuit held that FERC's jurisdictional determination was not arbitrary or capricious and rejected the generators' arguments that FERC improperly failed to consider the effect that its order would have on the justness and reasonableness of the CAISO tariff and that they would not have participated in the voluntary station-power program if they had known that FERC's netting interval would not govern retail sales. The Court pointed out that the generators could deregister at any time and that there were available means of redress should they incur retroactive charges, either to the CA Public Utilities Commission or to FERC.

2. *Ralls Corp. v. Comm. on Foreign Investment in the U.S. (D.C. Cir. February 26, 2013)*

On February 26, 2013, the DC Circuit ruled on a case brought by a corporation owned by two Chinese nationals against the U.S. government. The corporation attempted to acquire several windfarm projects in the vicinity of a U.S. Naval installation in Oregon, but President Barack Obama issued an executive order prohibiting the transaction under section 721 of the Defense Production Act (DPA). The President's order found that the corporation and its owners might exercise their control over the companies in a way that could threaten to impair U.S.

national security. Neither the order itself nor a statement released by the U.S. Treasury Department provided any detail as to exactly what threat the corporation posed to national security, but stated that evidence of such a threat was "credible." The extent of the conditions imposed by the order, along with the fact that the corporation is controlled by a newly appointed member of the Chinese Communist Party's Central Committee—China's second richest citizen, valued at $8.1 billion—has led some to speculate that the move was intended to prevent surveillance by the Chinese of the U.S. naval base.

The order compelled the corporation to divest the assets and imposed further conditions on the disposition of both the projects and the turbines. The corporation brought claims that the President's order was *ultra vires*, *i.e.*, that he had exceeded his authority, that the President violated the Constitution by denying the corporation's owners equal protection, and that the corporation was denied due process. The government moved to dismiss on jurisdictional grounds.

Section 721 of the DPA states plainly that "[t]he actions of the President . . . and the findings of the President . . . shall not be subject to judicial review." The Court therefore dismissed the plaintiff's *ultra vires* and equal protection challenges for lack of jurisdiction, but declined to dismiss the plaintiff's due process claim because it raises "purely legal questions about the process that was followed in implementing the statute." The Court was careful to note that it was not ruling that the due process claim had merit, but rather that it was bound to decide the claim on its merits. The Court determined that it will reach a decision on the due process claim after further briefing by the parties.

B. United States Court of Appeals for the Second Circuit

1. *Simon v. KeySpan (2d Cir. September 20, 2012)*

On September 20, 2012, the Second Circuit upheld the validity of FERC's market-based rates (MBR) , affording this category of prices the protection traditionally afforded tariffs set by a regulatory agency.

The suit began in 2010 when the U.S. Department of Justice (DOJ) filed a civil complaint alleging that KeySpan—now a part of National Grid—had unlawfully restrained trade by indirectly entering into an agreement with the Astoria Generating Company (Astoria), using Morgan Stanley as an intermediary.

FERC investigated the arrangement and concluded that KeySpan had not violated regulations prohibiting market manipulation, noting that "[m]arket participants . . . have always known that KeySpan, pursuant to the applicable market-mitigation rules, was permitted to offer at its cap and set the market-clearing price." KeySpan settled its case with the DOJ "without trial or adjudication of any issue of fact or law" by paying the U.S. $12 million.

Retail customers then brought claims against KeySpan for violations of federal antitrust law as well as New York law, arguing that they were injured when they purchased electricity from Con Ed, which had in turn purchased it in the form of installed capacity through the auction process. The district court, *inter alia*, dismissed both the federal and state claims with prejudice in 2011.

On appeal, the Second Circuit upheld the district court's ruling and further held that the plaintiffs' state and federal claims were foreclosed by the filed rate doctrine which states that "any 'filed rate'—that is, one approved by the governing regulatory agency—is *per se* reasonable and unassailable in judicial proceedings brought by ratepayers." When it applies, the court stated, the filed rate doctrine is "rigid and unforgiving." The court held that although FERC did not directly set the rate at issue here, FERC's MBR auction process "was sufficiently safeguarded such that the filed rate doctrine should apply."

C. United States District Court for the Northern District of New York

1. *Aukema v. Chesapeake Appalachia; Beardslee v. Inflection Energy (N.D.N.Y. November 15, 2012)*

In a pair of cases decided on November 15, 2012, the District Court for the Northern District of New York ruled in favor of plaintiff landowners seeking declarations that oil and gas leases they had entered into with the defendant extraction companies had expired. The extraction companies argued that the primary terms of the leases had been extended due, inter alia, to force majeure

The defendants cited then- Governor David Paterson's directive requiring the Department of Environmental Conservation (DEC) to update and supplement the 1992 Generic Environmental Impact Study (GEIS) on high-volume hydraulic fracturing (HVHF) as, in effect, a moratorium on natural gas development constituting force majeure. The lease defined force majeure, among other things, as including "acts of public authorities." Being prevented from developing the lands due to a force majeure event, the defendants argued, should extend the term of the leases beyond their stated dates of expiration.

The Court held that the DEC's de facto moratorium did not frustrate the purpose of the leases, which it characterized as "to explore, drill, produce, and otherwise operate for oil and gas and their constituents." The Court noted that although the moratorium halted horizontal drilling using HVHF, it did not limit the defendants' ability to drill using another method, even if no other method was commercially viable. "Mere impracticality," the Court held, "is not enough to excuse performance," and therefore force majeure did not extend the leases and they expired according to their original terms.

D. <u>United States District Court for the District of Vermont</u>

1. *Entergy v. Shumlin (D. Vt. September 11, 2012)*

On September 11, 2012, a pair of Entergy subsidiaries filed a complaint for declaratory and injunctive relief and a motion for preliminary injunction challenging the implementation of Vermont's Electrical Energy Generating Tax (EET). The EET assessed a tax of $0.0025 per kWh upon "electric generating plants constructed in the state subsequent to July 1, 1965, and having a name plate generating capacity of 200,000 kilowatts, or more." Entergy opposed the tax, arguing that it had been tailored to apply only to the Vermont Yankee nuclear plant and therefore is an impermissible effort by the State to single out Vermont for discriminatory treatment.

On October 25, 2012, the US District Court granted Vermont's motion to dismiss the case for lack of subject matter jurisdiction. The Court held that under the Tax Injunction Act (TIA), which prohibits federal courts from enjoining the collection of state taxes when the party challenging the tax has a "plain, speedy, and efficient remedy" in state court, prevented it from hearing the case. Entergy argued that the Vermont assessment was not a tax, but was in fact a regulatory fee, not subject to the TIA. The Court instead followed the Second Circuit Court of Appeals' decision in *Travelers Insurance v. Cuomo*, which held that assessments imposed primarily for revenue-raising purposes—as opposed to punitive or regulatory purposes—are taxes. Because the revenue from the EET is designated to the State's general fund, and not to any specialized fund or agency, the Court determined that it was a tax subject to the TIA. The

Court further held that Entergy could avail itself of either an administrative remedy or action in Vermont state courts, barring federal review of the case.

2. <u>New York Independent System Operator</u>

A. FERC Rules on NYISO's Order No. 1000 Compliance Filing (April 18, 2013)

On April 18, 2013, FERC issued its ruling partially accepting the Order 1000 compliance filing jointly submitted by the NYISO and New York transmission owners (collectively, the "Filing Parties"). Among other things, Order 1000 required each system operator to amend its Open Access Transmission Tariff (OATT): (1) to ensure that the transmission provider participates in a regional transmission planning process that produces a regional transmission plan; and (2) to describe procedures that provide for the consideration of transmission needs driven by public policy requirements (PPRs) in the local and regional planning processes.

IPPNY protested several key aspects of the Filing Parties' compliance filing. Most notably, IPPNY asserted that although Order 1000 contemplates a role for state regulators, the role the Filing Parties assigned to the PSC—whereby the PSC both selects projects and mandates their implementation—does not comply with the Order. IPPNY also took issue with how the compliance filing called for the consideration of non-transmission alternatives. In the filing, the NYISO would only consider such alternatives at the PSC's request; IPPNY argued that FERC should direct the NYISO to consider such alternatives as a matter of course. Additionally, IPPNY protested the Filing Parties' proposed default load ratio share method for the cost allocation of PPR projects, arguing that such a method would socialize costs to all customers across the State with no regard for whether those customers benefitted from a particular project. Finally, IPPNY protested the expansion of the definition of PPR to include PSC orders.

FERC was receptive to many of IPPNY's arguments. On the role of the PSC, FERC adopted IPPNY's position, stating that "a state entity or regional state committee can consult, collaborate, inform, and even recommend a transmission project for selection in the regional transmission plan for purposes of cost allocation, but the public utility transmission providers in a transmission planning region must make the transmission project selection decision, not the state entity or regional state committee." Similarly, with respect to the process for selecting PPR projects, FERC stated:

> [w]e agree with commenters who suggest that NYISO should have a central role in selecting transmission solutions proposed to meet transmission needs driven by public policy requirements and find that NYISO does not comply with this requirement of Order No. 1000. As discussed above, a public utility transmission provider has an affirmative obligation to select more efficient and cost effective transmission solutions in the regional transmission plan for purposes of cost allocation.

FERC ordered the Filing Parties, in their subsequent compliance filing, to (1) eliminate provisions in the reliability transmission planning process allowing the state to select transmission solutions for purposes of cost allocation; and (2) include in the reliability transmission planning evaluation/selection a process whereby NYISO selects the more efficient or cost-effective solution that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation.

FERC also agreed with IPPNY that the Filing Parties' proposal did not adequately provide for comparable treatment of non-transmission alternatives in the consideration of transmission needs driven by public policy requirements. FERC directed the Filing Parties in their subsequent compliance filing to (1) identify how non-transmission solutions will be evaluated in the PPR planning process "such that all types of resources are considered on a comparable basis"; and (2) revise the OATT to provide for interested parties to propose non-transmission alternatives.

FERC agreed with IPPNY on the subject of cost allocation as well, rejecting the compliance filing's proposed default load ratio share method. FERC stated that "Order No. 1000 requires the Filing Parties to show that the regional cost allocation method allocates the costs of new transmission facilities in a manner that is at least roughly commensurate with estimated benefits," and determined that the NYISO's compliance filing "does not explain in sufficient detail how costs are allocated in accordance with estimated benefits" or ensure "that those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities." FERC did, however, accept the Filing Parties' proposal that the developer of a proposed PPR project, DPS Staff, or the PSC could designate how costs of PPR projects should be allocated because the NYISO is required to file any such proposed cost allocation mechanisms with FERC for approval.

FERC declined to adopt IPPNY's position on the expansion of the definition of PPR, finding that the inclusion of a PSC order adopting a rule or regulation complies with Order 1000. FERC directed the Filing Parties to revise the proposed definition in their subsequent filing, removing the phrase "that drives the need for expansion or upgrades to the NYS bulk transmission facilities" and clarifying expressly that the NYISO will consider as a PPR duly enacted laws or regulations passed by a local governmental entity.

FERC directed the Filing Parties to submit a further compliance filing responding to the issues it rejected within 120 days of its order.

B. *NYISO Approves Comprehensive Reliability Plan (March 22, 2013)*

On March 22, 2013, the NYISO announced the approval by its Board of Directors of the 2012 Comprehensive Reliability Plan (CRP) for New York's power system. The CRP concludes that the system will need additional transmission and generation resources during the 2013-2022 study period, but that sufficient solutions have been proposed to meet those reliability needs.

The CRP found that permanent solutions identified in Rochester Gas & Electric and National Grid's local transmission plans (LTPs) will resolve the needs identified in the 2012 Reliability Needs Assessment (RNA) for the Rochester and Syracuse areas. The CRP found further that proposed market-based solutions such as NRG's repowering of the Astoria and Dunkirk plants and Constellation's increase of demand response, if acted upon, would fully meet the resource adequacy needs for 2021 and 2022 identified in the RNA. Finally, the CRP found that certain risk factors, including the need for transmission owners' LTPs to proceed on schedule, the influence of financing, future market conditions, and interconnection requirements on the timely completion of market-based generation solutions, and the retirement of additional generating units could adversely affect system reliability over the 10-year planning horizon potentially resulting in immediate transmission security and resource adequacy criteria violations.

C. *FERC Orders NYISO to Recalculate Mitigation Exemption Determinations for Two NYC Capacity Suppliers (September 10, 2012)*

On September 10, 2012, FERC issued an order granting, in large part, a complaint filed by Astoria Generating Company (Astoria) and TC Ravenswood, LLC, two NYC generator owners. FERC's order provided important clarifications of how the NYISO must apply its buyer-side market power mitigation rules, which are designed to protect the installed capacity (ICAP) market from uneconomic entry. FERC's order strengthens those rules and makes it more difficult for ICAP from new NYC projects, financed by discriminatory, above-market contracts, to be sold in the ICAP market and artificially depress clearing prices.

The complaint, which IPPNY supported, challenged the NYISO's decisions to exempt certain plants from the minimum offer floor requirement that must be applied to all new entrants in the NYC ICAP. FERC found that when the NYISO performed the mitigation exemption test (MET) for the plants in question, it violated buyer-side market power rules in four ways. First, FERC ruled that the buyer-side market power rules prohibit the NYISO from issuing final mitigation determinations prior to the completion of the interconnection cost allocation process for the applicable class year. Second, FERC ruled that the NYISO was wrong to conduct the MET based on outdated information. Third, FERC ruled that it was improper for the NYISO to exclude from the calculation of the Unit Cost of New Entry (CONE) allegedly sunk costs associated with shared facilities. Fourth, FERC ruled that the NYISO improperly used the actual cost of capital, rather than a proxy cost of capital, because that cost of capital was the result of a discriminatory power purchase agreement (PPA) with NYPA. FERC agreed that the PPA was "an out-of-market payment" that would lower the project's risk, "enabling it to attract debt and equity capital investors on more favorable terms inconsistent with a competitive offer."

FERC ultimately ordered the NYISO to recalculate its exemption determinations for the two plants, but declined to require that past ICAP auctions be re-run so as to avoid market uncertainty. FERC stated that "[b]ecause we are not requiring a retroactive remedy, if and at such time that NYISO determines that the subject projects are not exempt, NYISO should apply the applicable offer floor prospectively from the date of the determination for the period provided in the Services Tariff."

STATE MATTERS

1. New York Courts

A. Appellate Division, Third Department

1. *Norse Energy v. Dryden & Cooperstown Holstein v. Middlefield (N.Y. App. Div. 3d Dep't May 2, 2013)*

On May 2, 2013, the Third Department of New York's Appellate Division released rulings on two cases involving the ban of the practice of high volume hydraulic fracturing (HVHF) by municipalities. Both cases, *Norse energy Corp. v. Town of Dryden* and *Cooperstown Holstein Corp. v. Town of Middlefield*, were brought by parties with an interest in the development of gas resources on property within the towns, either as extractors or property owners.

In August of 2011, the Town of Dryden amended its zoning ordinances to ban all activities "related to the exploration for, and the production or storage of, natural gas and petroleum." In June 2011, the Town of Middlefield enacted a similar prohibition through its zoning law. Anschutz Exploration Corp., Norse Energy's predecessor in interest, and Cooperstown Holstein Corp. owned oil and gas leases for various parcels of land subject to the prohibitions and therefore brought Article 78 actions to have the bans invalidated on the grounds that local laws relating to oil and gas drilling are preempted by New York's Oil, Gas, and Solution Mining Law (OGSML). In February 2012, the lower courts in both cases decided in favor of the towns and ruled that the OGSML did not preempt the zoning ordinance.

On appeal, the Third Department affirmed the lower court's ruling and held that the OGSML does not preempt local governments from regulating land use. The court relied on the delegation to local governments of the power to regulate land use through zoning laws as "[o]ne of the most significant functions of a local government." Although it pointed out that the legislature can preempt a local government's home rule powers either expressly or impliedly, the court found that the OGSML did not do either.

The OGSML contains a supersession clause which states that the statute's provisions "shall supersede all local laws or ordinances relating to the regulation of the oil, gas[,] and solution mining industries; but shall not supersede local government jurisdiction over local roads or the rights of local governments under the Real Property Tax Law [RPTL]." The court noted that the statute does not define the term "regulation," and cited an online dictionary definition of the term as referring to "'an authoritative rule dealing with details or procedure.'" The court found that the ordinance at issue did not seek to regulate the details or procedure of the oil or gas mining industry, but rather sought only to regulate land use generally. Further, the court held that conflict with the OGSML did not cause local zoning ordinances to be preempted because regulation of the extraction industry's technical operations may "harmoniously coexist" with local zoning laws. The court stated that local zoning laws "will dictate in which, if any, districts zoning may occur, while the OGSML instructs operators as to the proper spacing of the units within those districts."

B. Supreme Court, County of Livingston

1. *Lenape Resources v. Town of Avon (N.Y. Sup. Ct. November 13, 2012)*

On November 13, 2012, Lenape Resources filed a complaint against the Town of Avon challenging the Town's moratorium on oil and gas exploration and extraction. Lenape's complaint is similar to that of the plaintiff extractors in the *Dryden* and *Middlefield* cases—discussed above—in that it claims that the Town's prohibition is preempted both expressly by Article 23 of the Environmental Conservation Law (ECL) and by virtue of its inherent conflict with the terms of that Article.

Unlike the plaintiffs in the previous cases, though, Lenape advanced the argument that even if the Town's prohibition is found to be enforceable, it constitutes a regulatory taking. Lenape argued that because oil and gas leases are instruments conveying an interest in real property—i.e., the right to explore and reduce hydrocarbons to possession—the enactment of the prohibition deprives the leaseholder of that property and entitles the leaseholder to compensation. Specifically, Lenape argues that the loss of its rights under the leases entitles it to a minimum of $50 million. The inclusion of the argument may prove a point of conflict for the Town—its prohibition is either preempted or, if the court accepts Lenape's argument, the Town must pay for the leases frustrated by its prohibition.

Furthermore, Lenape's complaint named the DEC as a mandatory party. As such, the DEC will have to respond formally and may be forced to take a position on local preemption, which it has heretofore managed to avoid.

2. New York Public Service Commission (PSC)

A. *Case 12-T-0502 – Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*

In an Order issued April 22, 2013, the PSC established procedures for the joint review of proposed projects intended to upgrade New York's alternating current (A/C) transmission system. The review stems from the PSC's request in November 2012 for proposals to alleviate congestion by increasing A/C transmission from upstate to downstate by 1000 MW. The specific transmission corridors being targeted transverse the Mohawk Valley Region, the Capital Region, and the Lower Hudson Valley, including facilities connected to the Marcy, New Scotland, Leeds, and Pleasant Valley substations, as well as the Central East and UPNY/SENY interfaces.

In the initial stage of the Commission's review, the Order states that the NYISO was requested to screen the 16 proposed projects to determine which would address the goals of increasing system reliability, flexibility, and efficiency, allowing for easier entrance and exit of generation sources, increasing the diversity of supply, enabling the development of lower cost upstate generation resources, fostering economic development and job growth, and reducing emissions. The NYISO found that north-south proposals offered multiple options along the Hudson Valley and Marcy South routes that would address congestion issues.

For the next phase of review, the PSC will work within the existing Article VII structure to consider competing proposals—assuming Article VII applications are filed—on a combined record. The Order established a common deadline of October 1, 2013, for all initial applications. Initial applications must provide the information required by certain sections of the Public Service Law (PSL) and corresponding regulations, including, inter alia, the appropriate intervenor funding fee; notice that the System Impact Study (SIS) and the System Reliability Impact Study (SRIS) are in progress; and a scoping statement and schedule detailing how and when the applicant will comply with the remaining sections of the PSL and regulations. Applicants must provide proof of service and notice to affected communities on or before the October 1 deadline, and the Order advises developers to make diligent efforts "to identify and avoid or minimize impacts on areas of concern identified through this early outreach."

The goals of the scoping phase are to make sure that the proposed scopes meet the requirements of Article VII and to establish an overall schedule for the remainder of the proceeding, including a common deadline for the completion of all individual applications. Each application is to be filed as an Article VII case with its own case number, but all of the applications will be reviewed on a common record and evaluated comparatively.

Additionally, the Order adopted certain new Article VII regulations, for which it received earlier comment, and expressed the belief that more modifications would be considered to facilitate the application process. Additionally, the PSC acknowledged that its existing cost-recovery mechanisms are not designed to compensate non-incumbent developers who cannot collect costs from designated customers. The PSC directed Staff to present both further proposed changes to the existing Article VII regulations and a straw proposal addressing cost recovery principles as soon as possible.

A technical conference open to the public is scheduled to take place on Tuesday, May 14, 2013. At that conference, DPS Staff will explain the process set out in the PSC's April Order, after which attendees may ask questions of the presenters. Interested parties may submit questions or suggested changes to the language of the Article VII regulations by email ahead of the conference to streamline the process.

B. ***Case 12-E-0503 – Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans***

On November 30, 2012, the PSC issued an Order calling for the development of a reliability contingency plan to address concerns relating to the potential closure of IPEC after the expiration of its Nuclear Regulatory Commission (NRC) licenses in 2015. Stating that "[t]he potential retirement of a significant generating facility, such as [IPEC], requires significant advanced planning," the PSC ordered Consolidated Edison of New York, Inc. (Con Edison), in consultation with the New York Power Authority (NYPA), to develop a contingency plan in the form of a Request for Proposals (RFP) that would address system reliability needs by the summer of 2016 (the In-Service Deadline). The PSC ordered that the contingency plan take into account "the status of proposed plants and AC and DC transmission projects, as well as the potential impacts of energy efficiency, distributed renewable generation, demand response, and combined heat and power projects," and that it include halting mechanisms in the event IPEC remains operational.

On February 1, 2013, Con Edison and NYPA filed a plan in response to the PSC's November Order (Contingency Plan). In the proposed Contingency Plan, Con Edison and NYPA proposed the immediate implementation of—and cost recovery for—their own $300 million energy efficiency and demand reduction (EE/DR) program, and adjusted the base case under the assumption that the EE/DR program would be implemented fully. The Contingency Plan then proposed a two-pronged, multi-step approach. First, the Plan proposed that the PSC issue an order in March 2013 requesting that NYPA issue an RFP to solicit 1350 MW of new incremental generation and transmission proposals that could be in place by the In-Service Deadline. Second, the Plan proposed that the PSC issue an order in April 2013 directing Con Edison (and New York State Electric and Gas Corporation (NYSEG) with respect to one transmission solution) and request NYPA to immediately begin development of, and authorize cost recovery for, three Transmission Owner Transmission Solutions ("TOTS") so that they can be in place by the In-Service Deadline. The three TOTS, two of which are also part of the Transco AC Transmission Proceeding submission and all of which Con Edison and NYPA propose will be transferred to and owned by the New York Transmission Company (NY Transco) are: (1) the Second Ramapo to Rock Tavern 345 kV Line (at an estimated cost of $123 million); (2) the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project (at an estimated cost of $76 million); and (3) the Staten Island Un-bottling (at an estimated cost of over $300 million). Con Edison and NYPA further proposed that in its April order the PSC find that the TOTS are public policy projects, meeting the public policy requirements of New York State as identified in the November 30, 2012 Order and the

New York Energy Highway Blueprint. Finally, the Contingency Plan called for DPS Staff to evaluate all projects received through the RFP and recommend to the PSC which projects should move forward to completion.

IPPNY and other commenters raised multiple objections to the items contained in the Contingency Plan. Among other things, commenters raised concerns about the TOTS being given an advantage over other projects proposed through the RFP, the PSC's lack of jurisdiction over NYPA, the Plan's reliance on a cost recovery mechanism for public policy projects that is not presently incorporated into the NYISO tariff, the fact that the Plan's inadequate halting mechanism could harm competitive markets, and that the Plan did not substantively address many of the concerns the PSC outlined in its November Order.

On March 15, 2013, the PSC issued an Order approving the RFP portions of the Contingency Plan, subject to certain modifications. The PSC ordered NYPA to provide the revised RFP for Staff review prior to its issuance, and required that responses to the RFP be submitted to the Commission at the same time they are submitted to NYPA. NYPA issued the RFP on April 04, 2013, and the due date for response is May 20, 2013.

On April 18, 2013, the PSC issued an Order approving the second part of the Contingency Plan. The Order authorized cost recovery for preliminary development activities associated with the TOTS, but capped the costs recoverable at $10 million to limit the financial exposure of ratepayers prior to September 2013. In September, the PSC anticipates issuing another order that will determine, based on DPS Staff's evaluation of their relative costs and benefits, which projects from among the TOTS and RFP responses would proceed.

The PSC rejected comments made by IPPNY and other parties that allowing the TOTS projects to proceed and recover costs, albeit in a limited amount, biases the selection process in favor of the TOTS and against other RFP responses. The PSC did respond, however, to IPPNY's objections to the Contingency Plan's characterization of the TOTS projects as public policy projects eligible for state-wide cost allocation. The PSC found that it would be improper to allocate costs to all customers throughout the State, and that allocation of costs for the TOTS projects should adhere to the "beneficiaries pay" principle. In this case, the PSC found that the projects' beneficiaries would be those who received the reliability benefits—principally customers in zones in Southeast New York. The PSC directed DPS Staff to develop a straw proposal to allocate the costs of all transmission, generation, and demand-side solutions to retail ratepayers according to beneficiaries-pay principles, and to issue that straw proposal for further comment.

Finally, the PSC identified numerous deficiencies in the Contingency Plan's proposed EE/DR program. The PSC directed Con Edison to work with the New York State Energy Research and Development Authority, in consultation with NYPA, to jointly prepare and submit a revised plan within 45 days. The PSC stated that, based on this revised plan, which it will consider together with responses to the generation/transmission RFP, it expects to establish program goals and budgets before the end of the summer.

C. *Annual Reporting Order*

On January 23, 2013, the PSC issued an Order implementing annual reporting requirements for wholesale generators subject to lightened regulation. In 2012, IPPNY requested greater flexibility in the reporting requirements to accommodate various corporate structures and accounting methods. The PSC's Order incorporated some of IPPNY's comments, allowing for some increased flexibility.

The PSC determined that holding companies that prepare financial statements at a level upstream from their New York operational subsidiaries can comply "by reporting information extracted from the holding company's consolidated financial statement at the Annual Report format's balance sheet and income statement." The PSC also recognized, as IPPNY noted in its comments, that wholesale generators are not subject to cost of service regulation and therefore do not necessarily conform their accounting practices to the Uniform Systems of Accounts (USOA). The PSC ordered revisions to some reporting categories, allowing for a more generic approach and better accommodating the variation in lightly-regulated companies' accounting practices. To further protect reporting flexibility, the PSC opted not to define more narrowly the cost classification categorizations and terminology in the revised format.

The PSC dismissed IPPNY's recommendation that the reporting format be tied to Electric Quarterly Reports (EQR) reporting. Rather, the PSC determined that it would not be "unduly difficult" for wholesale generators to combine data from all sources into the PSL Annual Report. Nor did the PSC grant IPPNY's proposal to confer automatic confidentiality protection on Annual Report filings before they are made as a matter of course, but stated that generators can file their Annual Reports subject to requests for confidential treatment

D. *Case 10-T-0139 – Champlain Hudson Power Express Article VII Proceeding*

On April 18, 2013, the PSC granted Champlain Hudson Power Express, Inc. a Certificate of Environmental Compatibility and Public Need ("Certificate") pursuant to Article VII of the Public Service Law to construct and operate the transmission project known as the Champlain Hudson Power Express Project. The Certificate adopts most of the terms and conditions of the February 2012 Joint Proposal (JP), as modified by subsequent stipulations and the Recommended Decision (RD) issued on December 27, 2012.

The principal portion of the Project is a High Voltage, Direct Current (HVDC) transmission line extending approximately 330 miles from the New York/Canada border to a converter station in Astoria, Queens. The HVDC transmission line will be sited underwater in Lake Champlain and the Hudson River, with underground and upland segments, ultimately interconnecting, through a converter station to be built in Astoria, Queens and an underground conduit, to the Rainey Substation.

The Project will have the capacity to transmit 1,000 MWs of, according to the Certificate, primarily hydroelectric power into the New York City load pocket.

The PSC found that the construction and operation of the line will impose minimal financial risk on ratepayers and that its grant of a certificate is in the public interest. The PSC concluded that the Project satisfies a need by (i) providing additional transmission capacity into the New York City load pocket; (ii) enhancing fuel diversity and energy security in the City by adding an additional source of supply – hydroelectric power – that is both renewable, relatively stable in price, and which may amount to over 10% of NYC energy consumption; (iii) advancing the PSC's policy favoring competition; and (iv) advancing State policies by enabling access to a supply of clean energy.

The PSC also found that the proposal would either avoid or minimize environmental impacts, citing, among other factors, the undergrounding of the line as providing both visual and land use benefits compared to siting the line above ground, ensuring the preservation of sensitive habitat by rerouting around environmentally sensitive areas, the siting of the land-based portions of the line in existing rights of way, and the use of horizontal directional drilling.

The Commission found that the Project is consistent with express provisions of state and local long-term infrastructure plans, specifically the 2009 State Energy Plan and New York

City's PlaNYC. The Commission found that, among other things, the Project would "continue the State's efforts to increase use of renewable energy resources and to bring such resources to the State's major urban areas."

Finally, the Commission found that the Project will serve the public interest, convenience, and necessity. In support of this finding, the Commission relied on (i) the reduction of emissions resulting from an addition of 1000 MW of hydropower into the NYC load pocket; (ii) the increased fuel diversity and enhanced competitiveness that the Project is likely to bring; and (iii) the inclusion of "Condition 15", which, according to the Commission, prevents the Project's proponents from seeking a direct subsidy to offset Project costs, as sufficient to ensure that captive ratepayers will not bear those costs.

E. *Case 12-E-0400 – Petition of Cayuga Operating Co. to Mothball Generating Units 1 and 2*

On December 17, 2012, the PSC issued an order deciding reliability issues and addressing cost allocation and recovery in the petition of Cayuga Operating Company (Cayuga) to mothball units 1 and 2 at its facility in Lansing, NY. The two coal-fired units, which both entered service in the 1950s, have a combined capacity of approximately 312 MW. Cayuga filed notice of its intent to mothball the units in July of 2012, but NYSEG's subsequent reliability analysis determined that the retirement of the units could cause adverse reliability impacts. In October of 2012, NYSEG submitted, for Commission approval, a proposed term sheet for Reliability Support Services (RSS), including the payment structure for and other provisions of the RSS service Cayuga would provide.

The Commission approved the RSS term sheet; it covers a one-year period, beginning on January 16, 2013, and expiring on January 15, 2014. One of the RSS term sheet's provisions concerns Cayuga's capacity revenues. Under the agreement, those revenues are to be credited against NYSEG's monthly payments to Cayuga. Another of the contract's provisions commits Cayuga "to offer its units into the capacity market at a de minimis price." The term *de minimis* is not defined, but it is arguably reasonable to interpret that phrase to mean that Cayuga is obligated to offer its capacity into the market at a level guaranteed to clear the NYISO capacity auctions. In its order, the PSC explained that the de minimis requirement is necessary to prevent Cayuga from offering its facilities at a price too high to clear the capacity market, thereby benefitting other generating units Cayuga owns.

Therefore, although Cayuga has attempted to mothball its units due to economics, the RSS agreement will extend the duration that Cayuga's uneconomic facilities remain in the capacity market. IPPNY has consistently opposed such an arrangement in discussions with the NYISO, contending that, where reliability resources are uneconomic and only remain in service due to RSS contracts, they should not be included in the capacity market because they artificially suppress capacity revenues.

On January 16, 2013, NYSEG filed an RFP Process and Schedule proposing the solicitation of resources "to meet reliability needs created by the mothballing of the Cayuga Facility for the period following expiration of the current [RSS] Agreement . . . to the time that more permanent improvements can be implemented." The Schedule calls for the issuance of an RFP in April 2013, with responses due in June 2013 and the awarding of contracts to take place in August 2013.

F. *Case 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements*

On January 18, 2013, the PSC issued an order instituting the above-named proceeding and requiring the evaluation of repowering existing generation facilities as an alternative to transmission system upgrades. In the Order, the PSC noted that the planned retirements of the coal-fired Dunkirk and Cayuga plants raised reliability concerns, making them appropriate candidates for a study of the repowering alternative.

The PSC Order directed National Grid and NYSEG, the utilities responsible for local reliability in their respective service territories,, to evaluate repowering as an alternative outcome for the Dunkirk and Cayuga retirements over a term of at least ten years. The utilities have already entered into short term RSS agreements with the generators, as noted above, and have been developing transmission reinforcements and other alternatives to those agreements. To address their local reliability concerns in the longer term, the utilities have proposed transmission solutions that will take four or more years to complete.

The Order directed the utilities, within 30 days, to file the projected costs of their proposed transmission solutions with DPS Staff and to solicit bids from the retiring plants' owners for the level of out-of-market support required to finance the repowering. The deadline for those bids was set at 60 days after issuance of the Order and they have been submitted. The Order further directed the utilities to use the information provided to conduct an "informed evaluation" and provide a report of their repowering analyses to the Commission within 90 days of the Order. These reports must detail the methods used to compare the alternatives, not only as they relate to reliability impacts, but also addressing ratepayer costs, the environment, the economy, and the competitiveness of the electric market. As of this writing, the PSC has granted both utilities an extension of the report deadlines, which are now due to be filed by May 17, 2013.