UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources **Docket No. RM10-11-000**

PUBLIC INTEREST ORGANIZATIONS' REQUEST FOR REHEARING OF ORDER NO. 764

Pursuant to the Federal Power Act ("FPA"), 16 U.S.C. 825l(b), and Rule 713 of the Federal Energy Regulatory Commission ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.713, the undersigned Public Interest Organizations ("PIOs"),[1] respectfully submit this Request for Rehearing of the Commission's Order No. 764, *Integration of Variable Energy Resources*.[2]

I. SUMMARY AND SPECIFICATION OF ERRORS

This rehearing request seeks additional Commission action that will contribute to solving variable energy resource ("VER") integration barriers in a manner that both prevents unjust and unreasonable transmission service rates and undue discrimination and makes significant progress towards a sustainable electric system and a clean energy future. PIOs commend the Commission in its efforts in Order No. 764 to remove unduly

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[1] Alliance for Clean Energy New York, Citizens Utility Board of Wisconsin, Climate and Energy Project, Conservation Law Foundation, Energy Conservation Council of Pennsylvania, Environment Northeast, Environmental Defense Fund, Great Plains Institute, Natural Resources Defense Council, Pace Energy and Climate Center, Sustainable FERC Project, Sierra Club, Union of Concerned Scientists, The Wilderness Society, Western Grid Group, Western Resource Advocates and Wind on the Wires.

[2] Order No. 764, *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012), hereinafter referenced as "Order No. 764" or "Final Rule". For simplicity, citation to the Final Rule will be solely to the relevant paragraph. This order resulted from the Notice of Proposed Rulemaking in *Integration of Variable Resources*, FERC Stats. & Regs. ¶32,664 (2010) ("NOPR").

discriminatory practices and address barriers to integrating VERs so as to ensure just and reasonable rates for Commission-jurisdictional services. PIOs agree with the Commission's general approach in Order No. 764, and support the Commission's efforts to remove market and operational barriers to VER integration, assure just and reasonable rates for transmission services needed by VERs, and prohibit undue discrimination against VERs. In particular, PIOs agree with the Order's requirements for each transmission provider ("TP") to: (1) offer intra-hourly transmission scheduling; and (2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the TP for the purpose of power production forecasting.

Notwithstanding our support for these provisions of Order No. 764, PIOs respectfully submit that the Commission has invited unjust and unreasonable treatment of VERs, and the imposition of new barriers to integration of VERs, by permitting TPs on a case-by case basis to file tariff proposals for Schedule 10-type regulation service. PIOs submit that the solution adopted by the Commission is worse than the problem it intended to address and that unintended consequences are likely to result. Therefore, for the reasons set forth below, PIOs request that the Commission grant rehearing, and expressly provide that TPs shall recover VER integration costs system-wide in the same manner that they recover the costs associated with the integration of "conventional" generation. Failure to so provide allows for unlawful discrimination between VERs and conventional generation, which contravenes Sections 205 and 206 of the FPA.

In the alternative, PIOs request that the Commission delay implementation of

Schedule 10-type service for two years after the effective date of Order No. 764. That period would allow for measurement of the beneficial impacts projected by the Commission from the Final Rule's new requirements of intra-hour scheduling and VER power production forecasting, including reduced need for and cost of Schedule 10-type service regulation service. PIOs submit that over the proposed two-year period FERC will likely find that the benefits of the reforms required will reduce or eliminate the need to allow direct allocation of integration costs to VERs through Schedule 10-type service.

If the Commission does not grant rehearing to eliminate the opportunity of TPs to file for Schedule 10-type service, or postpone the effectiveness of Order 764 as to that issue, PIOs submit that the Commission should: (a) adopt the conditions set forth in Section IV., C below, in addition to the six conditions adopted in the Final Rule regarding Schedule 10-type service; and (b) convene a technical conference to address implementation of the six conditions in Order No. 764 and the alternative conditions proposed in this request.

II. STATEMENT OF ISSUES

(1) Whether the Commission acted in an arbitrary and capricious fashion, and without substantial evidence or reasoned decision-making, in concluding that generation from VERs is not similarly situated to generation from conventional generation. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 57 (1983); *Missouri Public Service Comm'n v. FERC*, 601 F.3d 581, 585 (D.C. Cir. 2010).

(2) Whether the Commission's ruling that transmission providers may seek approval for a generator regulation rate service structure that treats VERs differently than conventional generation, is arbitrary, capricious, discriminatory and not supported by reasoned decision-making or substantial evidence. See 16 U.S.C. §§ 824d and 824e; *State Farm and Missouri, supra.*

(3) Whether the Commission in Order No. 764 acted in an arbitrary and capricious fashion, abused its discretion, and failed to engage in reasoned decision-making, by not considering or addressing the position of PIOs that imposition of Schedule

10-type service upon VERs, but not conventional generation, is discriminatory.

III. <u>BACKGROUND</u>

PIOs agree with the Commission's general approach in Order No. 764, and support the Commission's efforts to remove market and operational barriers to VER integration and thereby better assure just and reasonable rates for transmission services needed by VERs, and avoid undue discrimination against VERs. The Commission correctly finds that current hourly scheduling protocols may impose unjust and unreasonable energy imbalance charges on VER customers whose output fluctuates beyond their control during the scheduled delivery hour. The Commission also properly concludes that hourly protocols are insufficient to provide the flexibility TPs need to optimize the efficiency and effectiveness of their systems. PIOs also agree with the Commission's ruling that operators of new VERs should provide to the TP meteorological and forced outage information, so as to assist the TP in improving the accuracy of its forecasting.

Instead of adding a generic Schedule 10 to the *pro forma* OATT as set forth in the proposed rule, the Commission provided guidance for the development of generation regulation service charges (P 315), which it will address on a case-by-case basis. (P 268). This guidance included six principles for TPs to apply in developing generation regulation service charges. FERC developed the principles in part to ease the "difficult and complex determination" of calculating the impacts of individual customers or customer classes on a TP's overall generation regulating reserve needs, and the allocation of costs associated with these impacts. (P 317).

The six principles require that the TP, in its Section 205 filing to implement generation regulation service, must: (i) justify, based on operational characteristics, any request to charge different classes of customers for different quantities of generator regulation service (P 318); (ii) to the extent operational characteristics are claimed as the justification for dividing customers into different classes, provide "detailed explanations" of why the creation of different classes is justified and how the TP is taking diversity benefits into account (P 319); (iii) to the extent different classes with different regulation responsibilities are proposed, demonstrate that the aggregate quantity of regulating reserve the TP requires accounts for diversity benefits among all resources and loads, and that individual allocations to customers or classes are proportional based on operating characteristics of such customer or class (P 320); (iv) include seasonal weather events that may affect the need for generator regulation service in the data set for determining generator regulation service needs throughout the year (P 321); (v) consider the extent to which customers are using intra-hour scheduling in determining whether to require different customers to purchase different quantities of the service (P 322); and (vi) address their use of power production forecasting in any proposal to differentiate generation regulation capacity requirements among customers or classes of customers (PPs 323, 325).

IV. <u>ARGUMENT</u>

A. The Commission's General Conclusion that VERs "Are Not Similarly Situated" to Conventional Generation Ignores Similarities in Both Uncertainty and Variability.

The Commission summarily states, without explanation, that "VERs, by definition, are not similarly situated to conventional, dispatchable generators", and that "VERs are not similarly situated in all respects to conventional, dispatchable generators." (P 47). Whatever value that this declaration may have as a general matter, both types of generation share attributes of both uncertainty and variability. Indeed, even "dispatchability" is not a consistent distinction between conventional generation and VERs.[3]

The only citation provided in support of the "not similarly situated" declaration, footnote 66 of Order No. 764, does not support the Commission's conclusion because it simply refers to footnote 1 of Order No. 764, which in turn simply recites the NOPR's definition of a Variable Energy Resource as:

> a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities.

See Order 764 at n. 1, *quoting* Stats. & Regs. ¶ 32,664, at P 64.

To allege that VERs differ from conventional generation by simply referring to the definition in the NOPR is not reasoned decision-making, and simply imposes a circular logic, that "a matter is so because we define it as so". The NOPR definition of VERs requires the generation to be "renewable", and therefore "by definition" it cannot include most conventional generation. But this does not mean that they are not similarly situated in that both VERs and conventional generation impose both uncertainty and

[3] Wind and some other resources can be dispatchable. For example, MISO's tariff generally requires "interconnection customers to be dispatchable to interconnect" to MISO after March 1, 2011, including wind-fueled VERs. *Midwest Independent System Operator, Inc.*, 134 FERC ¶61,141 at P 42 (2011). Also suggesting that VERs are consistent with conventional resources respecting dispatchability,h Xcel reported to the Utility Variable Integration Group ("UVIG") that they require all new wind plants to provide automatic generation control ("AGC") and have regulated their Colorado service territory entirely with wind on AGC under circumstances where wind plants were first curtailed, then asked to respond to AGC signals, and finally provided all system regulation when conventional resources were "parked" or removed from AGC duty. Drake Bartlett, presentation, UVIG 2012 Variable Generation Workshop, Tucson, Az., February 7-10, 2012.

variability costs upon the system. Indeed, the amount of power available to operators at any moment is uncertain. Thermal generators routinely fail to start, trip offline, and produce less or more power than scheduled. Systems carry both operating and non-operating reserves to compensate for the uncertainties. Thermal unit output does routinely vary from its schedules. Certainly, the definition of a VER does not and should not determine applicable cost allocation principles.

The Commission therefore errs to the extent it intended its general assertion, that VERs are not similarly situated to conventional generation, should be determinative as to the specific issues of both uncertainty and variability. No factual or economic support is provided for this declaration. Nor does the Commission tie this declaration to its discussion of Schedule-10 type regulation service. Accordingly, the Commission's conclusion that VERs are not similarly situated to conventional generation is arbitrary, capricious, an abuse of discretion, and not founded on substantial evidence, and it should be reversed upon rehearing. *See e.g., PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194, 1198 (D.C. Cir. 2005), *quoting Motor Vehicle Mfrs. Ass'n of the United States, Inc, v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) ("FERC 'must examine the relevant data and articulate a satisfactory explanation of its action including a rational connection between the facts found and the choice made'").

B. The Commission in Order No. 764 Unlawfully Discriminates Between VER and Conventional Generation

PIOs submit that the Commission in Order No. 764 has failed to preclude the continuation of existing, or the creation of new, barriers to VER integration. The "end result" of Order No. 764 is to permit the imposition of unjust and unreasonable rates, because it would allow TPs to charge VERs directly for integration costs while allowing other generation integration costs to be spread system-wide, allowing TPs to treat VERs differently than conventional generation. Such discrimination is unlawful.

1. Permitting Schedule 10-type service is contrary to sound regulatory policy

Treating VERs differently than other generation by permitting TPs to impose Schedule 10-type of service charges is unsound regulatory policy. First, regulation service is the most expensive way to integrate resources. Permitting the use of this type of service for integrating VER will unnecessarily raise costs for all customers, as there are many other, lower cost ways of balancing the system. Thus, the approach permitted by the Final Rule is not sound regulatory policy. Further, the six conditions proposed to "tailor" Schedule 10-type service charges to VERs are simply unworkable. That also is not sound policy.

Moreover, the two reforms actually implemented in Order No. 764 compel actions that may well eliminate the need for Schedule 10-type service. As a matter of regulatory policy, these reforms should be applied first before allowing public utility transmission providers to seek a remedy for a problem that may not exist.

The Commission in Order No. 764 recognized that "calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generation regulating reserve needs and allocating those costs accordingly can be a difficult and complex determination." P 317. While difficulty and complexity alone are not reasons to avoid necessary determinations, the other mandates of Order No. 764 will increase the difficulty and complexity, and place in doubt the need for and accuracy of ultimate determinations.

For example, the Commission concedes that with the newly required intra-hour scheduling, TPs “will be able to rely more on planned scheduling and dispatch procedures and less on reserves to maintain overall system balance.” (P 322). Moreover, the power production forecasting requirement of the Final Rule provides TPs “with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve services.” PPs 323, 325).

The Commission’s recognition that the mandates of the Final Rule will reduce the need for, and therefore the cost of, providing regulation service for VERs, demonstrates that allowing TPs to propose Schedule10-type service is unnecessary and contrary to a coherent regulatory policy. This conclusion is corroborated by the fact that the Commission consistently treats the cost of conventional generation integration—its variability and uncertainty—as a cost to be recovered system-wide, as demonstrated below in section 2.

At a minimum, PIOs request that the Commission on rehearing determine that it will not permit TPs to file for Schedule 10-type of scheduling service until at least two years after the effective date of Order No. 764. This additional time will provide the Commission and industry with the opportunity to collect and analyze data concerning the impact of intra-hour scheduling and power production forecasting upon the need for such service.

2. Permitting TPs to require Schedule 10-type service for VERs discriminates against VER generation as compared to conventional generation

The underlying assumption of the Final Rule, that comparable entities (generators) can be treated differently by requiring some to pay for generator regulation service, renders the order invalid because it is discriminatory. Instead, comparable customers must be treated on a comparable, non-discriminatory basis.

FPA Section 205 (b) provides that "no public utility shall, with respect to any transmission … subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." 16 U.S.C. § 824d(b).

Order No. 764 violates this mandate by allowing TPs to charge VERs for their contribution to system variability (their grid integration capacity reserve costs) while allocating the costs of the variability associated with conventional generation (*e.g.,* the capacity reserve costs related to their forced outages) across all system customers. Conventional generation imposes significant variability costs on the system. For example, conventional generation requires the procurement of contingency reserves to cover forced outages and generation trips, typically at the scale of the largest single generator in a balancing area, which can exceed 1,000 MW. Operating reserves are also required to meet NERC reliability standards. The costs of these reserves, which are almost always exponentially higher than the costs to the grid from VER variability, are spread broadly across customers in a given balancing area or region.

The comments on the NOPR filed by the American Wind Energy Association ("AWEA") demonstrate the discrimination against VERs that would be imposed by Schedule 10-type scheduling service.[4] For example, AWEA notes:

VERs and other generation resources are similarly situated to

[4] AWEA Comments at 28-32.

> conventional generation resources when it comes to the crucial point that they both exhibit variability and uncertainty in their output. While the timing and nature of the variability and uncertainty of conventional generators are in some ways different from those of VER generators, it would be impossible to argue that the behavior of either resource would not fit into the category of variability and uncertainty. When a conventional generator experiences variability and uncertainty in the form of forced outages…the conventional power plant's output varies over time and varies from what it was expected to produce—the exact definition of variability and uncertainty.[5]

AWEA's comments also cite extensive FERC precedent that the cost of accommodating the variability and uncertainty in the output of conventional generators is not only large, but broadly allocated to load, rather than the generators that cause them.[6]

As in the case of conventional generators, VERs provide important energy and economic benefits to the electric system, and in order to ensure comparable treatment, costs of the reserves to handle the uncertainty and variability of this newer generation should also be spread across all customers that benefit. In this regard, the costs of dispatching and operating resources to keep the system in balance are spread broadly

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[5] *Id.* at 30.

[6] *See, e.g., Cal. Indep. Sys. Operator Corp.*, 131 FERC ¶ 61,280 at PPs 46-50 (2010) (rejecting argument
that system-wide allocation of costs for ancillary services to regional load for scarcity conditions is not
consistent with cost causation principles); *Midwest Indep. Transmission Sys. Operator*, 125 FERC ¶ 61,322 at P 16 (2008) (dismissing argument the Midwest ISO ASM program violates precedent and cost causation principles because certain load-serving entities ("LSE") were not exempted and finding that ISO's management of ancillary services provides reliability benefits for all market participants); *Midwest Indep. Transmission Sys. Operator*, Inc., 122 FERC ¶ 61,172 at P 217 (2008) (not adopting request that the costs associated with scarcity prices be allocated to LSEs responsible for scarcity condition rather than socialized); *id.* at P 391 (finding that ISO proposal to allocate costs of operating reserves on the basis of energy usage, or load, to be reasonable since it reflects cost causation principles and allocates costs appropriately to the beneficiaries of ancillary services); *id.* at P 397 ("We do not consider it a shortcoming of the Midwest ISO proposal that the costs of regulating and contingency reserves are not allocated to generators since the Midwest ISO has other charges and provisions that serve the function of performance incentives for generators."); *Cal. Indep. Sys. Operator Corp.,* 119 FERC ¶ 61,076 at PPs 90-91 (2007) (CAISO's procured ancillary services support use of entire CAISO Control Area and, therefore, it is appropriate to allocate such procurement costs to all load in the CAISO Control Area).

across all customers in a service territory.[7] This broad cost recovery principle applies to the costs of Schedule 5 and 6 services, which cover the contingencies necessary to protect against conventional generation variability (e.g., forced outages, trips).[8] There is no persuasive reason to stray from this principle to address variability associated with VERs, especially in light of the relatively low economic impact VERs pose on transmission customers as compared to conventional generation contingencies.[9]

All generation sources impose integration costs on the system, and the issues of uncertainty and variability are system-wide concerns. These integration costs are a system-wide challenge that stems from the legacy transmission system and markets that evolved to support the operation primarily of large central-station generation. All of the transmission customers that receive the benefit of a balanced system should share in the expense of providing one. Accordingly, the Commission should expressly amend the Final Rule to prohibit transmission providers from charging different volumetric reserve requirements to different types of generators based on their overall variability profile.

The Final Rule's determination not to implement Schedule 10, but instead to allow for the imposition of Schedule 10-like charges on a case-by-case basis, does not alleviate PIO concerns because it may result in the imposition of discriminatory service on a case-by-case basis. While the six conditions for implementation of a Schedule 10-type of service may mitigate the extent of the discrimination, the efforts to apply these criteria will be a burden on limited Commission and industry resources, and the "end

[7] *See, e.g.,* Affidavit of Brendan Kirby attached to the comments upon the NOPR filed by AWEA.
[8] *Id.*
[9] As a further example, contingency reserves exist to ensure reliability in the case of a large loss to the system, like the forced outage of a nuclear or baseload coal facility. The costs for contingency reserves are not covered by the nuclear or coal generators alone, but shared across each system.

result" itself will be inherently discriminatory.

3. The failure of the Commission to address PIOs' comments and concerns is arbitrary, capricious, and an abuse of discretion, and does not constitute reasoned decision-making

Order No. 764 fails to address the concerns of PIOs directly, and it does not explain how the six principles applicable to any Schedule 10-type of filing will ensure avoidance of the concerns that PIOs raised. For example, PIOs in their comments (pp. 13-16) opposed the NOPR's generator regulation service as unjust, unreasonable and discriminatory towards VERs. While the Commission identifies some of these arguments by PIOs (PPs 248 and 299), it provides no specific consideration or discussion of these concerns.

PIOs respectfully submit that the failure of the Commission to address their concerns about the implementation of generation regulation service renders invalid the "guidance" provided in the Final Rule for future TP implementation of generation regulation service. *See, e,g, PSEG Energy Resources & Trade LLC v. FERC,* 665 F.3d 203, 208 (2011) (FERC's failure to respond meaningfully to objections raised by a party renders its decision arbitrary and capricious).

C. Alternatively, the Commission Should Condition Approval of Any TP Schedule 10-Type of Service Upon Compliance With One of Two Additional Conditions

If the Commission does not grant rehearing as requested in Section B above, PIOs submit that it should, at a minimum, condition any Schedule 10-type service upon compliance with additional guidance to complement the six principles in Order No. 764. The Commission should provide that acceptance of any generation regulation service submitted pursuant to the Final Rule will be conditioned upon the TP's utilizing a design that reflects one of the two following options.

First, the Commission could require TPs to implement a slower reserve service (akin to load-following or spinning reserves) to manage the type of variability VERs actually impose on the system, thereby eliminating unnecessary expense. The relatively minimal incremental balancing needs imposed by VERs can be provided via Schedule 3, as the Commission pointed out in the NOPR is already the case in some regions.

Alternatively, the Commission could require that the regulation service be designed to compensate only for the moment-to-moment balancing associated with generation variability, and not for VER variability that impacts the system beyond the balancing timeframe. That is, the costs of variability (the costs of reliable grid integration) imposed on the system by VERs beyond the moment-to-moment timeframe should be treated comparably to the costs related to the integration of other resources into the electric system.

In this regard, under the guidance in Order No. 764, it appears that transmission providers will not be prohibited from charging expensive regulation rates for VER output variability that impacts the system in the several minutes to hour timeframe. In fact, the Commission's use of the term "regulation" service is imprecise and could include both seconds-to-minutes, and minutes-to-hours. In the West, "regulation" is often used to refer to the service that handles all capacity variations within hourly intervals. Charging Schedule 10 rates for all schedule variations within an hourly period is likely to be unjust and unreasonable when other less expensive alternatives can be equally effective.

D. The Commission Should Convene a Technical Conference

PIOs submit that the Commission should convene a technical conference to address the operational issues associated with implementation of a Schedule 10-type service and to assure that costs imposed directly on VERs be just and reasonable. While the Commission in Order No. 764 essentially ignored requests to order a technical conference, PIOs submit that the need for this procedure is now even stronger in view of the new guidance provided by the six principles applicable to generation regulation service.

V. CONCLUSION

Wherefore, PIOs request that the Commission grant rehearing of Order No. 764 as described above. PIOs also request that the Commission convene a technical conference to further address issues arising from the six conditions the Final Rule imposes upon transmission providers seeking to institute Schedule 10-type service.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated in Washington, D.C. this 23rd day of July, 2012.

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