The Electricity Journal 29 (2016) 1–6

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/electr

All electrons are not local: A commentary on the interplay of recent U.S. Supreme Court decisions and state efforts to guide local transitions to clean power☆

David P. Yaffe

Of Counsel to Van Ness Feldman LLP, Washington, DC, and Seattle, USA

ARTICLE INFO

Article history:
Available online 23 June 2016

Keywords:
EPSA v. FERC
Hughes v. Talen
Clean energy
Capacity markets
FERC jurisdiction
NY Reforming the Energy Vision

ABSTRACT

A consistent assumption is that the market structures approved by FERC as a means of achieving the 'just and reasonable' rates required under the Federal Power Act are the necessary proxy for allocating jurisdiction between FERC and the states in clean energy development. If capacity markets are ultimately determined not to sustain the levels of capacity needed for the electric grid to function reliably and generation capacity declines below the specified levels, the efficacy of this construct will be called into question.

1. Introduction

Technology advances in the electric utility industry are driving market participants and regulators to grapple with the fact that the prevailing business model upon which regulatory structures are built is changing before our eyes. Many state regulatory authorities and legislatures are addressing the changes wrought and sought by new market participants: distributed generation large and small, the increasing intersection of the effects of climate policy, concerns about water and the need to maintain reliable electric service now and in the future. The states of California, Hawaii, Minnesota, and New York have been particularly active in reviewing old assumptions about their electric regulatory regimes. In 1996, the Federal Energy Regulatory Commission (FERC) established the foundation for separate treatment of the generation, transmission, and distribution segments of the industry through Order No. 888 (which approved regional transmission organizations (RTOs) and independent system operators (ISOs)), based on economic and market structure imperatives for a business model assuming one-way flows of power from central station generation to load. FERC and the states now find themselves trying to incorporate distributed generation, demand response, and other developments that suggest the growth of bi-directional power flows on the grid. To add to the strains faced by traditional electric regulators to accommodate an emerging business model, the federal Environmental Protection Administration (EPA) has entered the fray by proposing that *states* take regulatory action under environmental statutes to reduce the emissions of greenhouse gases from electric generation by changing generator dispatch. Such initiatives, in the form of the Clean Power Plan and related actions, may affect FERC jurisdictional areas. In addition, states are actively investigating how to promote "clean" energy sources within the limits of their own jurisdiction.

Incumbent generation owners, in turn, participate in both legislative and regulatory arenas to protect their existing assets and business models to the extent feasible.[1] Should rooftop solar participate in the wholesale energy markets? Do the states, FERC, both, or neither determine the market pricing signals for the efficient siting of new central station generation, and what pricing guarantees accompany the market structures designed to send such signals? To what extent should end users with their own [distributed] generation be permitted to participate in the local or regional energy markets instead of central station generation, and who controls that participation? These questions and others

☆ All opinions expressed in this article are solely those of the author and do not reflect the views of the firm or its clients.

E-mail address: dpy@vnf.com (D.P. Yaffe).

[1] *See, e.g.*, Getting Distributed Generation Right: A Response To "Does Disruptive Competition Mean A Death Spiral For Electric Utilities?", David Raskin, 35 Energy L. J. 263 (2014).

http://dx.doi.org/10.1016/j.tej.2016.06.003
1040-6190/

appear to have become most intractable in the context of whether the states or FERC have, or should have, jurisdiction over the measures addressing such issues.[2]

During its 2016 term, the U.S. Supreme Court issued two decisions emphatically establishing that the wholesale markets approved by FERC under the Federal Power Act (FPA) are the guideposts against which state regulatory and business model accommodations to electric industry evolution must be measured. These decisions are *Federal Energy Regulatory Commission v. Electric Power Supply Association,* 136 S. Ct. 760 (2016) (*EPSA*) and *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016) (*MdPSC-Talen*). These decisions, together with the *Oneok, Inc. v. Learjet, Inc.*[3] opinion in the previous term, require all current and potential participants in the electric utility (and natural gas) markets to analyze which transactions and regulatory decisions may affect wholesale electric (and natural gas) market structures as well as wholesale sales of electric energy and sales of transmission service and whether such developments are permissible within the current federal regulatory regime or require FERC's permission.

This article will explain the substance and import of these two decisions. It also will discuss the import of the Court's analytical framework on the evolution of state commission regulatory structures that are more accommodating to greater customer/end user participation in electricity markets.

2. The analytical framework: FERC-regulated wholesale markets must not be impinged upon by state regulation

2.1. *The* EPSA *decision*

EPSA addressed the issue whether FERC has jurisdiction to approve the purchase of, and establish a price for, demand response in the organized RTO and ISO markets. Demand response is called upon to reduce peak demands on the generating system. The coordinated and reliable imposition of demand response to avoid peaks is considered a way to reduce the need for construction of new generating facilities, generally fired by fossil fuels, solely to meet peak demand. Demand response reflects an amount of energy that aggregators arrange *not* to be consumed by retail customers during specified hours and which has been bid into the organized wholesale energy markets for such hours by the aggregators in return for a payment. The aggregators, under state authority, entered into contracts with end use electric consumers to reduce or eliminate their electricity demands/consumption during specified hours, in return for a payment for such foregone consumption.[4] The tariffs maintained by the RTOs and ISOs setting forth the structure and operational rules of the energy and related markets specifically addressed the terms and conditions for demand response participation.

The *EPSA* case arose specifically from an appeal of FERC's Order No. 745, the decision requiring the RTOs/ISOs to pay full locational marginal price (LMP) to demand response providers for each megawatt-hour of demand response/energy requirement foregone.[5] EPSA, the trade association of independently owned electric generators, joined by the American Public Power Association, the trade association for municipally and state-owned electric utilities, appealed. It argued that the FERC had no jurisdiction over demand response under the FPA because there was no "sale of electricity for resale" as specified under Sections 201 of the FPA. As an alternative, EPSA argued that if the FERC had jurisdiction, payment of full LMP was inappropriate because the end use customer already realized a savings in the amount of the generation component of the energy charge it did not pay for by reducing its demand.

In a 2-1 decision, the D.C. Circuit reversed FERC by finding that FERC did not have jurisdiction over demand response.[6] The D.C. Circuit took a literal approach in finding that since FPA Section 201 gave jurisdiction to FERC over "the sale of energy for resale" and demand response was the antithesis of the sale of energy, *i.e.* it is the reduction in demand for electric energy during a specific time period, demand response did not constitute the type of transaction delegated to the FERC's jurisdiction. Moreover, since the reduction in electric demand was coordinated between the local service provider and the end user, it was viewed as an inherently retail transaction that was preserved to state jurisdiction under FPA Section 201. The D.C. Circuit also held that FERC had not adequately explained its decision to compensate demand response providers at full LMP.[7] Judge Harry Edwards' dissent found that since solicitation of demand response would reduce the amount of demand that a RTO would be required to meet in any hour under its tariff and reduce the LMP for that hour, demand response was within FERC's jurisdiction under FPA Section 205(c) as a "practice affecting the rates, terms and conditions" of a FERC-regulated service.[8]

The Supreme Court's opinion restated FERC's FPA jurisdiction in terms of the economic function regulated in order to uphold FERC's position and reverse the D.C. Circuit. In her majority opinion, Justice Kagan began by explaining the delegation of jurisdiction between FERC and state authority under FPA Section 201 as well as how demand response works in the organized markets. She then described an evolution of FERC authority in the context of electric markets:

> In this new world, FERC often forgoes the cost-based rate-setting traditionally used to prevent monopolistic pricing. The Commission instead undertakes to ensure "just and reasonable" wholesale rates by enhancing competition—attempting, as we recently explained, "to break down regulatory and economic barriers that hinder a free market in wholesale electricity." *citing Morgan Stanley Capital Group Inc.* v. *Public Util. Dist. No. 1 of Snohomish Cty.*, 554 U. S. 527, 536 (2008). *EPSA*, 136 S. Ct. at 768.

The Opinion describes how the hourly energy market auction operates by taking orders from load-serving entities (LSEs) for electricity needed in a particular hour, the bidding by generators of the price to provide a stated amount of energy in that hour, and the auction operated by the RTO or ISO to match supply with demand at the highest price taken for each hour (that is, the locational marginal price). *Id* at 768-69. The Opinion delineates the negative effect of demand response on energy prices, *i.e.,* that demand response is a negative supply that limits the rate of energy price increase.

The opinion traced the unchallenged cohort of statutes and regulations that preceded Order No. 745. These included Section 1252(f) of the Energy Policy Act of 2005[9] that defines and encourages the participation of demand response in energy markets. *EPSA*, 136 S. Ct. at 770 and FERC Order No. 719, issued in 2008, that required wholesale market operators to receive demand response bids from aggregators of electric consumers unless prohibited by state law. *Id.* at 771. The Opinion then noted that Order No. 745 simply was the evolution beyond Order No. 719

[2] *See*, *e.g.*, *The Hazy "Bright Line"; Defining Federal and State Regulation of Today's Electric Grid*, Robert Nordhaus, 36 Energy L. J. 203 (2015); *Federalism and the net metering alternative*, James Rossi, The Electricity Journal, vol. 29, pp. 13–18 (2016) (hereinafter "Rossi Net Metering").

[3] 135 S. Ct. 1591 (2015).

[4] *EPSA*, 136 S. Ct. at 767.

[5] *Id*. at 771-72.

[6] *Elec. Power Supply v. FERC*, 753 F.3d 216 (2014).

[7] *Id.* at 225.

[8] *Id.* at 232.

[9] Pub. L. No. 109-58, § 1252(f), 119 Stat. 966 (2005).