Payment for Reactive Power

Commission Staff Report

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I. Introduction

In Order No. 784, the Commission revised its regulations to foster competition and transparency in ancillary services markets.[1] Among other things, the Commission revised Part 35 of its regulations to reflect reforms to its *Avista*[2] policy governing the sale of certain ancillary services at market-based rates to public utility transmission providers. However, the Commission found that the technical and geographic requirements associated with Reactive Supply and Voltage Control (Schedule 2) and Regulation and Frequency Response (Schedule 3) services precluded reforms to the *Avista* policy with respect to the sale of those services. Instead, the Commission stated its intention to gather more information regarding the technical, economic and market issues concerning the provision of these services. To that end, Commission staff will hold a workshop on April 22, 2014, to discuss these issues with interested participants.

In advance of this workshop, staff is releasing this paper to highlight some of the topics to be explored with respect to Schedule 2 service. Staff has examined issues surrounding the provision of reactive power several times over the last decade. The Commission established minimum requirements with respect to the provision of reactive power by large generators in Order Nos. 2003 and 2003-A.[3] Commission staff further considered a range of pricing and procurement options for reactive power in a report issued in 2005 (2005 Staff Report).[4] In Order Nos. 2006[5] and 661,[6] the Commission revisited reactive

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[1] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, FERC Stats. & Regs. ¶ 31,149 (2013), at P 61.

[2] *Avista Corp.*, 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61,136 (1999) (*Avista).*

[3] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), at P 546, *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, at P 416, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[4] FERC, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, Docket No. AD05-1-000 (2005) (2005 Staff Report), *available at* http://www.ferc.gov/EventCalendar/Files/20050310144430-02-04-05-reactive-power.pdf.

power issues with respect to small and wind-powered generators, generally concluding that small generators should be subject to the same requirements as large generators, but wind generators should not.[7] In 2012, staff held a technical conference to evaluate reactive power policies as applied to wind and solar generation, leading to additional, informal outreach by staff with respect to reactive power compensation practices in various regions.[8]

To date, the Commission has not required a uniform approach with respect to compensation for reactive power. As a result, different payment and cost recovery methods have been adopted in each region. Transmission providers in some regions pay a cost-based payment for reactive power capability, while others require reactive power capability as part of good utility practice, i.e., without compensation. For transmission providers that do pay for reactive power capability, the American Electric Power (AEP) methodology is generally used to compute cost-based reactive power capability payments. Although not currently used in any region, competitive solicitations could be implemented to procure and price reactive power service. To facilitate that approach, Order No. 784 established parameters for the use of competitive solicitations by public utility transmission providers seeking to acquire ancillary services for purposes of satisfying their Open Access Transmission Tariff (OATT) obligations. Regardless of the procurement mechanism used, alternatives to the AEP methodology could be used to develop rates for reactive power, such as a multi-part payment reflecting both the capability and the provision of reactive power.

In this paper, staff reviews existing and alternative approaches to reactive power compensation in order to facilitate discussion at the April 2014 workshop with respect to the technical, economic and market issues associated with Schedule 2 service. The paper begins with background information regarding reactive power, then reviews current

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[5] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[6] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[7] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 387; Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 at P 41-46.

[8] Notice of Technical Conference, Docket No. AD12-10-000 (Feb. 17, 2012).

methods used to pay for reactive power before turning to a discussion of alternative approaches for consideration.[9] To some degree, the compensation-related issues discussed herein might inform the discussion of technical, economic and market issues associated with Schedule 3 service. A notice of workshop and detailed agenda is being issued concurrently with this paper. Parties are invited to discuss this report at the technical conference.

II. Background

Reactive power is a critical component of operating an alternating current (AC) electricity system, and is required to control system voltage within appropriate ranges for efficient and reliable operation of the transmission system. At times generators or other resources must either supply or consume reactive power for the transmission system to maintain voltage levels required to reliably supply electricity from generation to load. In this section, we discuss transmission system needs for reactive power, types and sources of reactive power from different types of generation and transmission equipment, and the role of energy storage and demand response in provision of reactive power.[10] This background provides context for the discussions on payment for reactive power in later sections.

Ensuring that reactive power is adequate to support transmission service, whether from transmission system elements, generators, load, distribution system elements, energy storage, or an appropriate mix of these, is one of the transmission planning and operations responsibilities of the transmission planner and operator. Vertically integrated utilities meet reactive power needs by placing power factor requirements on generators and large loads, in addition to planning and operating their transmission and distribution systems to regulate voltages. In organized wholesale markets, the system operator (ISO or RTO) and transmission owners jointly set voltage schedules for both affiliated and independent generators in each transmission owner area, and consider future reactive power needs as part of transmission system planning.

Reactive power contributes to system voltage control: a device with a leading power factor tends to raise system voltage, while a device with a lagging power factor tends to

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[9] The report has several appendices with background material on reactive power and technical details of different types of generators: Appendix 1 – Technical Characteristics of Generators; Appendix 2 – Cost of Reactive Power Equipment; and, Appendix 3 – Details of OATT Schedule 2 Rates for Selected Transmission Providers.

[10] For more detailed background on reactive power provision by different types of generators, please refer to Appendix 1 of this report.

lower system voltage.[11] In this report, the term reactive power provision refers to operating with leading or lagging reactive power at the instruction of the transmission operator. The term reactive power capability refers to the ability to operate with leading or lagging reactive power if the unit is online and synchronized to the power grid, just as capacity represents the ability to provide (real) power if the unit is online and synchronized to the power grid. In general, operating with leading reactive power is called supplying reactive power, while operating with lagging reactive power is called consuming reactive power.

The transmission system needs reactive power to support system voltages to allow for transport of real power across transmission lines. Transmission lines dissipate reactive power more quickly than real power, meaning that reactive power cannot be efficiently transferred long distances on transmission lines. This is why many people say that reactive power "does not travel well," and results in geographic limitations on supply of reactive power.

Reactive power can be provided by a variety of resources. Generators can operate within a range of leading and lagging power factors with continuously variable reactive power output to meet the voltage schedule set by the transmission provider. Synchronous condensers are generators that have been disconnected from the mechanical turbine and only produce reactive power using real power from the transmission system. The reactive power produced by synchronous units can vary continuously over a range and can be used to regulate a bus voltage. By comparison, capacitors are a type of transmission equipment that provides a fixed amount of leading (or capacitive) reactive power. Inductors are another type of transmission equipment that provides a fixed amount of lagging (or inductive) reactive power. A combination of electronically controlled capacitors and inductors can be mechanically switched on and off to provide a stepwise reactive power source. To obtain a continuously variable reactive power source, transmission providers use power electronic devices, also called Flexible Alternating

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[11] Power factor is the ratio between a generator's real power (MW), reactive power (MVAr) and apparent power (MVA), where apparent power is the vector sum of real and reactive power. Mathematically, apparent power (MVA) = SQRT(MW^2 + $MVAr^2$), and power factor = (MW / MVA). The power factor range 0.95 leading to 0.95 lagging represents a power factor range of 0.10, from 0.95 leading up through 1 (also known as a unity power factor) and from 1 through 0.95 lagging. When a generator operates at a power factor of 0.95 leading, its output consists of 0.3 MVAr of leading reactive power for every MW of real power produced; likewise, when a generator operates at a power factor of 0.95 lagging, its output consists of 0.3 MVAr of lagging reactive power for every MW of real power produced.

Current Transmission Systems (FACTS), which have a combination of capacitors and inductors to provide continuously variable leading or lagging reactive power. Static VAr Compensators (SVCs) and STATCOMs are specific types of FACTS devices that are designed to provide voltage support. Loads generally have a lagging power factor, but capacitors on the distribution system are often used to adjust the power factor.

Reactive power sources are generally categorized as static or dynamic based on the speed and continuity at which they can produce or absorb reactive power in response to changes in system conditions. For example, mechanically switched capacitor and reactor banks are generally considered to be static reactive power sources, because they provide discrete blocks of reactive power through slow mechanical switches that cannot provide continuous voltage control. While a precise or consistent definition of dynamic reactive power is not available, in general, dynamic reactive power devices are characterized by faster acting and continuously variable voltage control capability, as described in the 2005 Staff Report.[12] Supply of reactive power from a dynamic reactive power source generally follows a smoothly increasing relationship; that is, an additional amount of reactive power is produced, up to the physical limit of the resource, for every additional input of mechanical energy (in the case of a generator) whereas a static supply of reactive power can only supply fixed amounts of reactive power.[13]

Static reactive power sources are usually deployed to respond to changing system conditions that are slow and more predictable, such as the seasonal or daily load shape and the resultant need for additional reactive power during peak load periods and reduced reactive power needs at night. Dynamic reactive power requirements are typically determined through a dynamic stability analysis, which considers system response immediately following an event or disturbance. Dynamic studies are also used to determine the equipment needed to meet the low voltage ride-through requirement of Order No. 661, which requires a wind plant to remain on-line during system voltage disturbances up to specified time periods and associated voltage levels.[14] The time

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[12] 2005 Staff Report at 26.

[13] The North American Electric Reliability Corporation (NERC) has also used this description of static and dynamic reactive power. *See* NERC, Reactive Voltage Control Whitepaper at 12 (2009), *available at* http://www.nerc.com/pa/stand/project%20200801%20voltage%20and%20reactive%20planning%20and%20c/project2008-01_white_paper_2009may18_appendix_1-11_2009aug17.pdf (NERC Reactive Voltage Control Whitepaper).

[14] Order No. 661-A, FERC Stats. & Regs. ¶ 31,198, at P 51-52.

interval studied generally covers a period of seconds. For example, the North American Electric Reliability Corporation (NERC) has specified two intervals for dynamic analysis: a transient interval from zero to three seconds, and a post-transient dynamic interval from three to 30 seconds.[15]

With respect to electrical generators in particular, units are generally divided into two categories, synchronous and asynchronous. Synchronous generating units consist of an electrical generator known as a synchronous machine and a mechanical turbine, and the generator produces electricity in sync with the transmission system at the system frequency (60 Hz in the U.S.). Synchronous generators have a rotating magnetic field which produces reactive power. Most wind generators use a different type of machine, known as an induction machine or asynchronous machine, to convert wind energy to electricity. Solar photovoltaic generators use semiconductors to convert solar energy to electricity. Both wind and solar photovoltaic are also called asynchronous generators since the electricity they produce is not initially synchronized with the AC grid. This is because either the rotor does not rotate at 60 Hz, in the case of wind generators, or the generator lacks a rotating machine and produces DC power, in the case of solar photovoltaic generators. In addition, some asynchronous generators consume reactive power, specifically older Type I and Type II wind turbine generators. On the other hand, some asynchronous generators, specifically newer Type III and Type IV wind turbine generators, and solar photovoltaic generators, interface to the transmission system with power converters that convert the electrical output of the generator to synchronized AC power that can be transmitted on the transmission system. These units have the capability to produce and control dynamic reactive power. Appendix 1 to this report has further details on synchronous and asynchronous generators.

Energy storage devices can provide reactive power in limited situations. The amount of reactive power support depends on the ability to store (or hold) electric energy and the equipment used to connect and control the energy storage device to the transmission system. Some energy storage devices use limited inverters that are not capable of providing reactive power, while others use an inverter similar to those used by wind and solar generators that allow the energy storage device to provide reactive power support. Pumped hydro storage uses a synchronous generator to produce real and reactive power and has the capability to provide reactive power identically to other synchronous generators while providing nearly instantaneous response to the transmission system needs for reactive power and other ancillary services such as frequency response and reserve energy.

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[15] NERC Reactive Voltage Control Whitepaper at 14.

Demand resources can contribute to voltage control, mainly by regulating the power factor at their delivery point to reduce the amount of reactive power ancillary service they need to purchase from their transmission provider.[16] In Order No. 890, the Commission determined that location and load profile could allow for the provision of reactive power to the transmission system by certain loads, and modified Schedule 2 of the pro forma OATT to allow for the provision of reactive supply and voltage control from non-generation resources, such as demand resources, where appropriate.[17] However, some transmission providers have suggested that unless demand is connected to a high-voltage transmission level interconnection node, provision of reactive power by demand response is of limited effectiveness in addressing transmission system voltage control.

III. Current Methods Used to Pay for Reactive Power Capability

In this section, we survey Commission precedent regarding methods currently used to pay for reactive power capability from generating units, as well as reactive power charges to transmission customers in Schedule 2 of several transmission providers.[18]

A. Commission Precedent

The Commission noted in Order No. 888 that transmission customers that control generating units are able to reduce their reactive supply and voltage control needs by setting the generator to control voltage, and that transmission customers who serve load can reduce their reactive supply and voltage control needs by maintaining a high power

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[16] *See* 2005 Staff Report, generally. Staff noted that in many cases load response and load-side investment could reduce the need for reactive power capability in the system and that increasing reactive power at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket. *See id*. at 4, 108. The report also noted that distributed generators have the same reactive power characteristics as large generators, as both types of generators produce dynamic reactive power, and the amount of reactive power does not necessarily decrease when voltage decreases. *Id*. at 27.

[17] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261, P 494 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[18] The costs of transmission equipment that provides reactive power are generally recovered through cost-based transmission rates, and we do not discuss those rates in detail in this paper.

factor at load delivery points.[19] The Commission determined, however, that these transmission customer actions to reduce reactive supply and voltage control needs would not entirely eliminate the need for generator-supplied reactive power. The Commission found it necessary to require that reactive supply and voltage control service be offered as a discrete service and, to the extent feasible, charged for on the basis of the amount required.[20] Pursuant to the *pro forma* OATT under Schedule 2, reactive supply and voltage control from generation or other sources service is to be provided directly by the transmission provider, or indirectly by the transmission provider making arrangements with the local control area operator that performs this service for the transmission provider's system.[21] The transmission customer is required to purchase this service from the transmission provider or control area operator.[22]

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[19] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002). [Order No. 888 at 31,706-31,707]. The Commission stated that it would evaluate whether transmission provider proposals for delivery point power factor standards in service agreements with customers are just and reasonable.

[20] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707 & n.359 (stating the possibility that separation of reactive supply and voltage control from basic transmission service could contribute to the development of a competitive market for such service if technology or industry changes resulted in improved ability to measure the reactive power needs of individual transmission customers or the ability to supply reactive power from more distant sources.) At that time the Commission recognized that these capabilities might not yet be fully developed.

[21] Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

[22] The Commission has taken a case-specific approach on self-supply of reactive power service. In some cases, the Commission has found that a self-supply option is inappropriate where the tariff provides that all generators will be compensated for their reactive power capability on a non-discriminatory basis, and all loads will pay their load ratio share of the costs of that capability. In other cases, the Commission has acknowledged a self-supply arrangement. *Compare Midwest Independent Transmission*

Transmission providers can meet their Schedule 2 service obligations by using their own resources or those owned by third parties. With respect to the use of third-party resources, the Commission's policies with respect to compensation distinguish between the provision of reactive power and reactive power capability. In Order No. 2003, the Commission required that generators be paid for reducing real power output to supply or consume reactive power.[23] In general, this is reactive power outside the required 0.95 leading to 0.95 lagging power factor range.[24] By comparison, the Commission did not require that an interconnection customer be compensated for reactive power when operating within its established power factor range since it is only meeting its obligation.[25] However, the Commission clarified in Order No. 2003-A that if a transmission provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the interconnection customer.[26] As a result, payment for reactive power capability varies by region and generally falls into two categories: some transmission providers make no payments for reactive power capability within the 0.95 leading to 0.95 lagging power factor range, concluding that such operation is a requirement under good utility practice;[27] and, some transmission providers

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System Operator, Inc., 113 FERC ¶ 61,046, at P 56-59 (2005), *order on reh'g*, 114 FERC ¶ 61,192 (2006); *American Transmission Systems, Inc.*, 119 FERC ¶ 61,020, at P 26 (2007) *with* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,706-31,707; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), at 30,228-29*; Georgia Power Co*., 89 FERC ¶ 61,157, at 61,443 (1999) (distinguishing between mandatory and voluntary provision of reactive power); *Southern Company Services., Inc*., 80 FERC ¶ 61,318, at 62,089 n.62 (1997), *reh'g denied*, 82 FERC ¶ 61,168 (1998); *see also Calpine Oneta Power, L.P.*, 124 FERC ¶ 61,193, at P 13 (2008) (rejecting proposed credit where transmission provider did not have operational control of the reactive power output of the subject plants).

[23] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 546.

[24] Under Order No. 2003, the required power factor range is 0.95 leading to 0.95 lagging, unless the transmission provider establishes a different power factor range.

[25] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546.

[26] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416.

[27] *See Entergy Services, Inc.*, 113 FERC ¶ 61,040 (2005); *Southwest Power Pool, Inc*., 119 FERC ¶ 61,199 (2007), *reh'g denied* 121 FERC ¶ 61,196 (2007) (*SPP*); *Bonneville Power Administration*, 120 FERC ¶ 61,211 (2007) (*Bonneville*), *reh'g denied* 125 FERC ¶ 61,273 (2008); *E.ON. U.S. LLC*, 124 FERC ¶ 61,131 (2008).

make cost-based payments for reactive power capability to compensate for the costs incurred to provide service and align financial incentives with desired operational behavior.[28]

In those regions where payments are made for reactive power capability, comparability of treatment between affiliated and non-affiliated generators has been an issue of concern. For example, the Commission accepted a rate of zero for reactive power within the required power factor range for both Bonneville and SPP, finding that the possibility that affiliated generators might have the opportunity to recover revenue lost from zero reactive power rates through retail rates does not create a comparability issue because there is no difference in the treatment that the transmission provider accords to affiliated and non-affiliated generators. In addition, the Commission noted that independent power producers may try to recover their lost revenue through higher power sales rates and that, in any event, reactive power costs within the deadband are generally small.[29]

However, the D.C. Circuit criticized this reasoning in a later case involving MISO rate schedules for reactive power. The court vacated Commission orders approving a separate rate schedule for MISO that would have allowed some transmission providers in MISO not to compensate generators in their transmission provider zones for reactive power capability within the required power factor range.[30] The Court found this policy of allowing a rate of zero in some zones but not others to be discriminatory, since generators in MISO compete across transmission provider zones. Reflecting on the Commission's position in the SPP and Bonneville cases, the court stated, "This appears to be a complete non-answer (or is based on a misconception of rudimentary economics)…. Generators that follow the Commission's advice to raise their power sales rates would suffer an increased risk of being undersold by generators from zones where reactive power costs are compensated."[31]

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[28] In addition to the general payment policies adopted by a particular transmission provider, additional payments are sometimes made to specific resources under reliability must run contract or through uplift payments to provide voltage support. This report does not cover the details of these arrangements.

[29] *Bonneville*, 120 FERC ¶ 61,211, at P 11, 21; *SPP*, 119 FERC ¶ 61,199, at P 17.

[30] *Dynegy Midwest Generation, Inc. v. FERC*, No. 09-1306 (D.C. Cir. Feb. 11, 2011).

[31] *Dynegy Midwest Generation, Inc. v. FERC*, No. 09-1306 (D.C. Cir. Feb. 11, 2011) at pp. 8-9.

For those third party generators receiving payment for reactive power capability, the Commission has required that such payments be based on the cost of providing reactive power. In Opinion No. 440, the Commission approved a methodology presented by AEP for its affiliated generators to recover costs for reactive power.[32] AEP identified three components of a generation plant related to the production of reactive power: (1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production (the AEP methodology).[33] Subsequently, the Commission indicated that all generators that have actual cost data should use this AEP methodology in seeking reactive power cost recovery.[34] The AEP methodology can be thought of as an option payment for the right to call on a generator for reactive power within the required power factor range.

In addition, the Commission has found that the compensation should not be based on the total quantity of reactive power a generator produces (MVArs/year, for example) or the number of hours it is online and thus available to provide reactive power.[35] The Commission has also found that if a needs test is applied to determine which generators to pay for reactive power, it must be applied in a non-discriminatory manner to all

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[32] *American Electric Power Service Corp.,* Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*).

[33] The factor for allocating to reactive power, developed by AEP, is $MVAr^2/MVA^2$, where MVAr is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of 1.

[34] *WPS Westwood Generation, LLC*, 101 FERC ¶ 61,290, at 62,167 (2002) (*WPS Westwood*). The inputs to the AEP methodology are disputed in some cases, and these are generally settled before a Commission administrative law judge. Generators that file FERC Form 1 use that data for some of the inputs to the AEP methodology. However, the Commission has granted waiver requests to most independent power producers of the requirement to file FERC Form 1, so they must provide other evidence to support the inputs to the AEP methodology.

[35] *See, e.g., Bluegrass Generation Company, L.L.C*, 121 FERC ¶ 61,018, at P 13 (2007) (*Bluegrass*); *Calpine Oneta Power*, *L.P.*, 119 FERC ¶ 61,177, at P 11 (2007) (*Calpine*).

generation sources of reactive power supply, including resources owned by the transmission provider and its affiliates.[36]

To date, there have been relatively few instances of market-based sales of reactive power to transmission providers. This has been due, in part, to the Commission's *Avista* restrictions on the sale of ancillary services to public utility transmission providers for purposes of meeting their OATT obligations.[37] In Order No. 784, the Commission revisited the *Avista* restrictions and determined that there was insufficient information to support elimination of those restrictions with respect to Schedule 2 service. Instead, the Commission concluded that sellers who have not been shown to lack market power with respect to reactive power could make market-based sales of Schedule 2 service to public utility transmission providers under two circumstances. First, they may do so at rates not to exceed the buying public utility transmission provider's OATT rate for the same service. The Commission found that because the buying public utility transmission provider's OATT ancillary service rates have already been found to be just and reasonable, it is reasonable to find that any third-party sales of the same ancillary service to that buyer at or below that buyer's own approved rates for that service would also be just and reasonable.[38] Second, they may do so pursuant to a competitive solicitation that meets certain requirements described in Order No. 784.[39]

B. OATT Schedule 2

Reactive power rates paid to generators are filed in individual rate cases and, therefore, are not easily identifiable in the aggregate. To better understand the magnitude of reactive power payments, staff reviewed the reactive power charges to transmission customers in Schedule 2 of several transmission providers' OATTs. Table 1 below compares the rates and details of Schedule 2; further details are included in Appendix 3 of this report.

For the regions that pay generators for reactive power capability, the rate paid is based on the Schedule 2 revenue requirement, which is then typically allocated to customers based on a load ratio share measured in MWh of real power. The Schedule 2 revenue

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[36] *See, e.g., Bluegrass*, 121 FERC ¶ 61,018, at P 14 (2007); *Calpine*, 119 FERC ¶ 61,177, at P 10.

[37] *Avista Corp.*, 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61.136 (1999).

[38] Order No. 784, FERC Stats. & Regs. ¶ 31,149 (2013) at P 82.

[39] *Id.* P 99-101.

requirement is based on the sum of the generator cost-based rates, which are generally based on the AEP methodology discussed above. If a transmission customer that serves load is able to maintain a high power factor at load delivery points, it would likely reduce real power losses and thus its real power load and Schedule 2 charges. Table 1 lists "N/A" for transmission providers that do not pay for reactive power inside the 0.95 leading/lagging power factor range or that do not charge a rate to transmission customers under Schedule 2.

Table 1: OATT Schedule 2 Rates

Region	Rate charged to transmission customers	Capability Rate	Capability Rate Calculation Method	Payment for actual reactive power?	Qualification Process	Specific Provisions for Non-generator sources?
ISO-NE	Formula in tariff, allocated based on load ratio	$2.19/kVAr-year	Settlement (based on AEP method)	Yes, see Appendix 3	Yes, see Appendix 3	Yes, see Appendix 3
NYISO	Formula in tariff, allocated based on load ratio	$3919/MVAr-year	Settlement	Yes	Yes, see Appendix 3	Yes, see Appendix 3
PJM	Varies by zone, allocated based on load ratio	Yes, individual resource revenue requirement	AEP methodology	Yes, based on LMP	None	None
MISO	Varies by zone, allocated based on load ratio	Yes, individual resource revenue requirement	AEP methodology	Yes	Yes, see Appendix 3	None
SPP	Formula in tariff	N/A	Opportunity cost	Yes, $2.26 per MVArh	Yes, see Appendix 3	None
Alabama Power	$1.32/kW-year	N/A	N/A	No	None	None
Arizona Public Service	N/A	N/A	N/A	No	None	None
Idaho Power	N/A	N/A	No separately identified cost/charges for this service.	No	None	None
PacifiCorp	$0 within PacifiCorp Zone; $0.18/MWh for service in both PacifiCorp & Mid-American	N/A	N/A	N/A	None	None
CAISO	N/A	N/A	N/A	Yes, based on LMP or RMR contract	Yes, CAISO tariff Appendix K part D	None

In addition, a uniform reactive power requirement does not account for the differences in cost recovery for independent and affiliated generators. This could result in disparate treatment of affiliated and independent generators in terms of cost recovery, since a transmission provider's own generators may be able to recover costs of reactive power capability through retail rates, but independent generators cannot. The Commission has rejected complaints on this issue by independent generators because they have not shown definitively that reactive power costs have been included in retail rates.[40] However, transmission providers have argued that, given how the transmission system is planned, their own and affiliated facilities are, in fact, needed for reliable operation of the transmission system, while non-affiliated generation facilities are not always needed and therefore should not necessarily be paid for their reactive power capability. Some transmission providers also argue that their own and affiliated units can be committed by the transmission provider for the purpose of providing reactive power, while non-affiliated units have no such obligation.

Finally, a uniform requirement for reactive power capability may result in over-procurement of reactive power capability, especially in generation-rich areas that have sufficient reactive power capability. A fixed, uniform requirement does not allow for any sort of quantification of the need for or benefit of additional reactive power capability to determine whether more reactive power capability is needed in a specific location or is economically efficient. Some transmission providers argue that there should be some sort of needs test to determine whether reactive power from a particular generator is needed in order to pay generators for providing reactive power.

IV. Alternative Approaches to Payment for Reactive Power Capability

Most static reactive power comes from capacitors, which are transmission equipment with costs recovered through transmission rates. In contrast, most dynamic reactive power, which is crucial to transmission system reliability, is provided by generators, sometimes without a cost recovery mechanism, *i.e.*, at a rate of zero. This results in a system where transmission customers pay for the less valuable service through transmission rates for static reactive power but do not always pay for the more valuable service of generator dynamic reactive power capability available to respond to contingencies.

There are benefits and disadvantages to treating provision of reactive power within the required power factor range as a requirement of interconnection. Benefits of this approach include potential lower costs of ancillary services to transmission customers and sufficient reactive power to meet reliability needs. Disadvantages of this approach include higher system costs, disparate treatment of a transmission owner's own and affiliated generators versus non-affiliated (independent) generators in terms of cost recovery, and potential over-procurement of reactive capability since it may be required

[40] *See, e.g.*, *Bonneville v. Puget*, 120 FERC ¶ 61,211 at PP 10-12, 21; *Entergy*, 113 FERC ¶ 61,040 at PP 11, 22-23.

from generators in areas where additional reactive power capability is not needed for reliability (for example, an area with sufficient existing reactive power capability). Specifically, a uniform rule requires all generators to provide uniform reactive power capability, which could result in higher system costs than a least-cost procurement and provision that incents efficient investment in reactive power capability. These higher costs would either be reflected explicitly in power prices through higher supply offers or implicitly, through reduced supply, as generators are built with less inherent reactive power capability above the uniform (minimum) requirement because they cannot recover their reactive power investment costs.

In this section, we discuss potential improvements to the AEP methodology, alternative approaches to cost-based payments, and the potential use of competitive procurements for reactive power.

A. Potential Improvements to the AEP Methodology

As discussed above, the AEP methodology is the Commission's current methodology for determining reactive power costs for generators and, while it is generally working, there are some areas for potential improvement. For example, while most transmission providers in outreach were satisfied with the payment method in their region and did not sense that generators had issues with it, none of the transmission providers that pay for reactive power capability were aware of any wind or solar generators applying to be paid for their capability. In addition, while generation owners were generally satisfied with the AEP methodology, they described some issues with determining costs to use in the AEP methodology, especially for generators that have been sold multiple times where records have not been transferred, creating uncertainty about the appropriate costs to use in the AEP methodology. Generation owners also generally would prefer that all regions pay for reactive power capability using something similar to the AEP methodology.

Another area for potential improvement has to do with the information required to compute reactive power costs. While some of the data required for the AEP methodology is contained in FERC Form 1 and are, therefore, publicly available and generally audited, many of the required data elements are not in FERC Form 1. In addition, most independent power producers have been granted waiver of the Form 1 filing requirement and so their data are not always publicly available or audited. This data needs to be collected and checked, typically through discovery requests during the discovery phase if the reactive power rate case has been set for hearing. It might be possible to avoid lengthy and costly litigation of this data, including the more detailed breakdown needed for the AEP methodology, if independent power producers were required to submit such data to FERC and the data were made publicly available. However, independent power producers regard much of the information collected in FERC Form 1 as commercially sensitive. Based on Order No. 784, a generator that does not have the information to use the AEP methodology could sell reactive power to its transmission provider at the Schedule 2 rate, which may save generators significant effort and litigation expense. In contrast, a generator in a region that pays for reactive power and that has the information to use the AEP methodology could calculate a cost-based rate based on the AEP methodology and file it with the Commission, even if that rate is higher than the Schedule 2 rate.

In addition, the AEP methodology may not be appropriate for asynchronous generators such as wind and solar photovoltaic generators, which may have completely different allocation issues than were addressed in the AEP methodology. Part of the reason no asynchronous generators have filed for reactive power compensation may be due to uncertainty about whether they are required to use the AEP methodology or even what appropriate methodology analogous to the AEP methodology could be used to compute reactive power rates for asynchronous units.[41] There also appears to be some question as to whether reactive power capability should be measured at the generator terminals, as it is for synchronous generators, or at the high-voltage side of the generator step-up transformers, as it is for asynchronous units.

In addition, based on outreach, both wind and solar generators have some additional concerns. Wind generators were unsure how to go about applying the AEP methodology, and expect that the first wind generator to apply to be paid for reactive power capability will encounter protests in its filing at FERC. The technical qualification requirements for reactive power payment are similar to tests that wind generators have to undergo in order to operate, and wind generators did not see these as a barrier to being paid for reactive power capability. While solar generators have not pursued compensation for reactive power capability because most solar generators are located in CAISO, and CAISO does not pay for reactive power capability, there is a cost to solar plants providing reactive power.[42]

In an attempt to standardize and improve transparency of the AEP methodology, the Commission could use the knowledge acquired from more than twenty years of experience with OATT Schedule 2 tariffs to establish a range of allocators that have been found to be just and reasonable for every thermal generation technology deployed in today’s bulk electric system. The Commission has extensive data in e-Library that could

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41 Most of the inputs to the AEP methodology are specific to synchronous generators, such as costs of specific parts of the generator, and thus cannot be applied to asynchronous generators without modification. For asynchronous generators, a new methodology based on the equipment that asynchronous generators use to provide reactive power would need to be developed.

42 April 2012 Conference transcript at 32 and 77, Docket No. AD12-10.

be used to establish such ranges of acceptable allocators for any given thermal generating technology. Additionally, the Commission could establish a spreadsheet outlining the AEP methodology while identifying a (tight) range of acceptable allocators. Establishing a Commission-approved spreadsheet with known acceptable allocators for specific generation technologies would have the effect of increasing the transparency of the AEP methodology, giving market participants better knowledge of expected revenue streams prior to making a FERC filing, and limiting the possible burden of litigation that many generators making reactive power tariff filings face.[43] Drawbacks to this approach include that it might result in relying on out-of-date cases or rates, and it would not address the challenges of developing rates for newer technologies such as wind turbines or solar photovoltaic generators. In addition, it could lead to over-recovery of reactive power costs, as generators with actual reactive power costs lower than the level they would recover using the acceptable allocators would accept the default allocators, while generators with actual reactive power costs above the level they would recover using the acceptable allocators may choose to file a rate using the AEP methodology and go through litigation if necessary.

B. Alternative Cost-Based Approaches to Reactive Power Compensation

One alternative to the AEP methodology would be to tie payment for reactive power to some measure of variable performance, rather than based solely on capability or on the actual provision of reactive power.

Economic theory of marginal cost pricing suggests the most efficient approach to pricing would be a multi-part payment based on both the capability and the provision of reactive power, rather than exclusively on one or the other. A pricing mechanism where the payment for reactive power capability is set to allow for the recovery of fixed costs, while the payment for the provision of reactive power is designed to approximate the marginal (or variable) cost (or value) of providing reactive power, may lead to increased efficiency in both production and consumption of reactive power as compared to a mechanism where a single price is set to compensate for both the capability and provision of reactive power. In addition, payments based on the amount and location of actual reactive power produced can incent generators to perform when they are called upon and where they are needed. However, there are some significant and complex issues with multi-part pricing for reactive power, including the proper value of reactive power production, and the appropriate penalty structure for non-performance.

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[43] Exelon put forward a similar proposal, suggesting a safe harbor provision of establishing reasonable ranges of reactive cost allocation to be accepted without a hearing, in its comments filed in response to the 2005 Staff Report and Technical Conference (Docket No. AD05-1).

Another issue with paying for reactive power production is the difficulty and complexity in determining the value of reactive power in real-time. If the transmission provider knows the reactive power capability curve of each generator, it may be able to calculate the opportunity cost of providing real power.[44] It may be possible to value reactive power production after the market runs, but co-optimizing real and reactive power in real-time markets remains an area of research. In addition, in most hours and at most locations on the grid, sufficient reactive power capability exists such that reactive power prices would usually be close to zero, yielding little incentive for generators to provide reactive power based on real-time prices alone. Also, real-time reactive power pricing may be particularly susceptible to exercise of market power or market manipulation due to the limited number of potential suppliers since reactive power needs are local and, unlike real power, reactive power does not travel very far.

However, since reactive power can be supplied by generators, transmission and load, the scope of potential suppliers and potential entrants is larger than just generators, highlighting the importance of getting the pricing of reactive power correct. For example, merchant transmission, demand response, or energy storage might provide reactive power if they could be paid. One example is the Cross Sound Cable merchant transmission line between New York and New England, which is paid for the reactive power capability it provides.[45]

A related issue is how to appropriately compensate generators for good performance and penalize them for poor performance. Commission precedent holds that reactive power payments are based on a generator's reactive power capability and its ability to follow the dispatch instructions of the transmission operator when online and synchronized to the transmission grid. This capability payment, using the AEP methodology, does not differentiate between units that are frequently online and those that are rarely online, or units that are typically online during times of system stress and those that are not. If the AEP methodology provides sufficient revenue for a generator to recover its costs of reactive power production, including its investment in reactive power capability, a return on that investment, and operations and maintenance costs, then allowing the generator to recover its cost of providing reactive power capability may allow the generator to recover all of its costs of providing reactive power without facing any penalties for non-

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[44] *See* Appendix 1 of this report for discussion of the reactive power capability curve, or D-curve, which illustrates the tradeoff between real power and reactive power production for an individual generator.

[45] ISO-NE OATT, Schedule 2, section B, *available at* http://iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

performance. In contrast, a reduction in the capability payment based on an administratively determined fixed price also raises concerns because certain units may only run for a few hours each year but their reactive power capability may be particularly valuable in those hours. If reactive power compensation and/or penalties are based on an average value of reactive power measured over a period of time, those units may not earn enough to recover their costs of reactive power capability and provision. This is analogous to the issues surrounding payment for real power reserves.

There are some possible administrative solutions to these complex issues, such as setting an administratively determined price for reactive power provision, or adjusting reactive power capability payments based on the number of hours a generator is online or the quantity of reactive power it produces. One example is MISO's approach, where if a generator fails to follow the system operator's reactive power dispatch three times in one month, the generator no longer qualifies for compensation under Schedule 2 of MISO's tariff.[46] But administrative solutions pose trade-offs between efficiency, equity, administrative simplicity, and providing the appropriate incentives. An administratively determined price for reactive power with a locational component seems attractive, as reactive power close to load centers would typically be more valuable, while reactive power that is distant from load may be less valuable. However, an administratively determined price would not accurately reflect the true value of reactive power at all times, particularly during times of scarcity, and could undervalue reactive power when it is most needed or overvalue it when it is not needed. Further, if combined with a reduction in capability payments to generators, this may lead to a shortage of reactive power at certain times in high-value locations like load centers. Also, basing reactive power capability payments on the number of hours a unit is online would not align incentives with desired generator locations for reliability. For example, payments based on the number of hours a unit is online would tend to increase payments to baseload units which may be located far from load while, as discussed above, decreasing payments to intermediate or peaking units that may provide reactive power where and when it is most needed. Similarly, basing payments on the quantity of reactive power produced may result in paying more to generators in areas with weak transmission where they will be required to provide reactive power in order to operate than to generators in areas with stronger transmission where they may be able to operate at close to a unity power factor.

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[46] *See* MISO Tariff Schedule 2 at IV.A.1: "If a Qualified Generator fails to comply with the Local Balancing Authority's voltage control requirements three or more times in a calendar month for reasons other than planned or unscheduled outages, the Transmission Provider shall determine whether the Generation Resource should continue to be a Qualified Generator based on the criteria established in Section II.B of this Schedule."

In addition, in ISOs/RTOs, participating generators can be committed to run for reliability reasons, including the provision of reactive power, and in those cases those units are paid uplift payments to ensure that their total payments from the ISO/RTO at least cover their running costs (i.e., start-up, no-load, cost of generation, minimum run time, shut-down); generators with a capacity obligation are also required to offer their supply into the day-ahead and real-time markets. Generators outside of ISOs/RTOs do not have the obligation to offer their units to the transmission provider and only have an obligation to provide reactive power when they are online, even if they are paid for their reactive power capability. This raises the question of whether a transmission provider should have the ability to require a unit that is paid for reactive power capability to run and provide reactive power support (assuming appropriate compensation for the running costs incurred by that unit). Another question is whether a generator receiving a reactive power payment is required to come online at the request of the system operator, or is only required to follow reactive power dispatch instructions when it is already online.

C. Competitive, Market-Based Solicitation of Reactive Power

In any market for reactive power, the Commission would need to consider market power concerns and how to address them. Due to the localized nature of reactive power, the relevant geographic market for reactive power may be much smaller than a market for real power. If transmission technologies, demand response, and energy storage provide reactive power, the market might be less concentrated than if only generation sources of reactive power were considered. Due to these concerns, the Commission established a set of minimum requirements in Order No. 784 with respect to the use of competitive solicitations by public utility transmission providers seeking to acquire ancillary services, including Schedule 2 service, for purposes of satisfying their OATT obligations.

Such competitive processes could elicit responses from a variety of resources, including generation, transmission, demand response, and energy storage. Transmission providers could use competitive solicitation to procure all or a portion of their reactive power needs. A competitive solicitation for reactive power production could incorporate mechanisms to acquire all reactive power services at least cost and to elicit desired performance from all reactive power resources. Alternatively, a transmission provider could use competitive solicitations to target the potential retirement of generation capacity due to economic conditions or environmental regulations that could result in a system need for reactive power at specific locations on the grid in the near future. In that case, the transmission provider could specify reactive power needs in terms of quantity, availability, type (static or dynamic) and location and all providers of reactive power (*i.e.* generators, transmission equipment, demand response, storage, transmission lines) could submit bids to supply those particular needs.

V. Conclusion

This report represents another step in the Commission's ongoing examination of issues surrounding reactive power. Starting with Order No. 888's inclusion of provision for reactive power from generators as an ancillary service in OATT Schedule 2, the Commission has issued a series of orders intended to ensure that reactive power is available and fairly compensated to support efficient and reliable operation of the transmission system. This report provides a discussion of issues surrounding payment for reactive power to facilitate discussion at the April 2014 workshop with respect to the technical, economic and market issues associated with Schedule 2 service. Staff invites parties to discuss concepts explored in this report at the workshop.

Appendix 1: Technical Characteristics of Generators

This attachment provides information on the technical characteristics of reactive power from different types of generators.

I. Background: Reactive Power

Reactive power is a component of alternating current (AC) power that is necessary to control system voltages for reliability, and to enable transmission of real power from generators to loads.[47] In an AC system, voltage and current vary sinusoidally at the system frequency of 60 Hz, and can be represented mathematically as phasors with a magnitude and phase angle. Apparent power is the product of voltage and current, and its magnitude is measured in volt-amperes, or MVA; this is the magnitude of a complex number, where real power (MW) is the real number and reactive power (MVAr) is the imaginary number. Power factor is the ratio of real power (MW) to apparent power (MVA). When voltage and current are in phase, meaning that they peak at the same time, power factor is one and reactive power is zero. When voltage and current are 90 degrees out of phase, the power factor is zero and real power is zero. Transmission operators control system voltages by controlling reactive power; producing (injecting) reactive power increases voltage, while reducing (absorbing) reactive power lowers voltage.

Reactive power can be produced or consumed by generators, power electronic equipment such as flexible AC transmission system (FACTS) devices, transmission lines and equipment, and load. When a generator produces reactive power, it raises voltage at the generator terminals; conversely, when a generator absorbs reactive power it lowers voltage at the generator terminals. Synchronous generators and FACTs devices produce what is called dynamic reactive power, which can be controlled instantaneously in small increments and is independent of transmission system voltage. In addition, inactive/retired generators and hydro generators can be used as synchronous condensers, where the synchronous machine operates to provide voltage support but the turbine and fuel parts of the generating unit no longer operate. Capacitors produce reactive power and raise or support voltage, while inductors absorb reactive power and lower voltage. Capacitors produce and inductors absorb what is called static reactive power, which is generally less expensive than dynamic reactive power, that switches on and off in fixed amounts, and provides less voltage support as transmission system voltage decreases. Capacitors, inductors, and FACTs devices can be installed anywhere on the transmission system.

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[47] For more detail on reactive power, *see* 2005 Staff Report.

Reactive power takes up space on transmission lines, and is dissipated by line reactance as distance increases. Transmission line heating losses are the square of the line current times the line resistance. Transmission line reactive dissipation is the square of the line current times the line reactance. For high voltage lines, reactance is generally ten times larger per line mile than line resistance, meaning that reactive power dissipation on a heavily loaded line is much larger than real power losses. Long transmission lines consume reactive power when heavily loaded; this is why it is often said that reactive power does not travel well, and should be produced near where it is used. Loads consume or produce reactive power depending on the type of equipment; some equipment could be built with dynamic reactive capability for transmission system support.[48]

A synchronous generating unit consists of a synchronous generator and a turbine. Generators have a reactive capability curve that represents the tradeoff between real and reactive power production, which is limited by heating limits of different parts of the electrical generator and the mechanical limit of the turbine. These limits are often described by a "D curve" because it is shaped like the letter D. The size of the turbine determines the maximum real power the generator can produce, while the size of the synchronous generator determines the maximum reactive power. Traditionally, the turbine and synchronous generator have been matched in size so that the generator can continuously produce reactive power in the required power factor range of 0.95 leading (consuming) and 0.95 lagging (supplying) without backing off its real power production. This power factor range corresponds to producing or absorbing an amount of reactive power up to approximately 30% of real power capacity.

Wind generators use a different type of machine, known as an induction machine or asynchronous machine, to convert wind energy to electricity.[49] Solar photovoltaic generators use semiconductors to convert solar energy to electricity. Both wind and solar are also called asynchronous generators since the electricity they produce is not synchronized with the AC grid. Asynchronous generators have power converters that convert the electrical output of the generator to synchronized AC power that can be transmitted on the transmission system. Power converters have power electronic

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[48] *See* Grayson Heffner, Charles Goldman, Brendan Kirby, Michael Kintner-Meyer, "Loads Providing Ancillary Services: Review of International Experience," Ernest Orlando Berkeley National Laboratory, Report LBNL-62701, page 9, *available at* http://certs.lbl.gov/pdf/62701.pdf (2007).

[49] Some Type IV wind generators use a synchronous machine that is not synchronized to the grid, and is connected to the grid through a power converter.

equipment, and can be designed to mimic the reactive power characteristics of a synchronous generator. This equipment is normally installed to regulate voltages within a wind or solar facility, but can also be designed to provide reactive power support to the transmission system. Early versions of wind generators, known as Type I/II generators, did not have power converters and absorbed reactive power from the transmission system. More recent wind generator designs, known as Type III/IV generators, based on doubly-fed induction generators, have power converters that allow the wind generator to absorb or produce reactive power in response to a control signal.

For both synchronous and asynchronous generators, reactive power capability is much less expensive to install when the generator is initially designed than to retrofit later.

Table 2 is based on staff research, compiled from a variety of sources.[50] Additional information regarding reactive power capabilities of various generation technologies can be found in the North American Electric Reliability Corporation's "2012 Special Assessment: Interconnection Requirements for Variable Generation."[51]

Table 2: Reactive Power Capabilities of Generators and Transmission Equipment

Generator or Transmission Element	**Reactive Power Range**	**Static or Dynamic?**	**Cost?**
Conventional Synchronous Generator	Most common dynamic reactive support provider; normally designed to operate continuously between 0.95 leading/lagging power factor and beyond that for short periods. When needed, synchronous generators can increase continuous reactive power output beyond the 0.95 leading/lagging power factor range by decreasing real power output.	Dynamic	All synchronous generators inherently have the components needed to provide reactive power. Increasing reactive power output (with a constant real power output) is achieved by incremental increases.

[50] 2005 Staff Report; NERC, *2012 Special Assessment Interconnection Requirements for Variable Generation* (Sept. 2012) *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012_IVGTF_Task_1-3.pdf (2012 NERC Report).

[51] 2012 NERC Report.

Generator or Transmission Element	**Reactive Power Range**	**Static or Dynamic?**	**Cost?**
Wind Type I	Uses induction generators, which absorb reactive power. Static capacitor banks are used to counter-act the reactive power consumed and are sized to yield unity power factor for the combined wind turbine and capacitor system.	No dynamic reactive power control	Adding reactive capability requires additional equipment.
Wind Type II	Uses wound rotor induction generators, which absorb reactive power. Static capacitor banks are used to counter-act the reactive power consumed by the induction motor. These are sized to yield unity power factor for the combined wind turbine and capacitor system.	No dynamic reactive power control	Adding reactive capability requires additional equipment.
Wind Type III	Uses wound rotor induction generators with power electronics connected to rotor, which allow control of reactive power. This is comparable to a typical synchronous generator, but smaller reactive power capability. The power electronics (AC to DC to AC conversion) act to convert the asynchronous power produced by wind power to the nominal AC frequency (60 Hz in US) by injecting an AC current of variable frequency into the generator rotor windings. The AC to DC to AC conversion also allows additional benefit for independent control of reactive power.	Dynamic	Literature suggests that a rating of approximately 30% to 35% for the power electronics is an optimum size for obtaining the desired real power at the generator terminal while allowing independent control of the reactive power.

Generator or Transmission Element	**Reactive Power Range**	**Static or Dynamic?**	**Cost?**
Wind Type IV	Uses variable frequency synchronous generators whose entire output is controlled by full rated power electronic converters. Can produce independent control of reactive power equal to full rating when wind turbines are not in service. This technology first converts the asynchronous power produced by wind power to DC and then converts it back to nominal AC frequency (60 Hz in US).	Dynamic	Power electronics and filtering equipment must be sized to 100% of generator rating for wind generator operation. A 100 MW wind unit would require installation of a 100 MW AC to DC to AC converter. In addition, to maintain a power factor of 0.9 leading/lagging at full real power output would require increasing the AC to DC to AC conversion by an additional 10%. This system would then be capable of maintaining 0.9 power factor at all power levels.
Solar photovoltaic	Reactive power limited to size of inverter and real power output of solar panels. If inverter is oversized to 110% of generator capacity then system can supply 46% reactive power at 100% real power output (0.91 leading/lagging) and 110% reactive power at 0 real power output.	Dynamic	Incremental cost of increasing inverter rating from 100% of generator capacity to 110% of generator capacity.
Switched Static Shunt Capacitors	Sets of capacitors mainly installed in substations and on circuits, which provide reactive support by injecting VARs into the power system. Reactive supply fluctuates with the square of voltage; at low voltage the output is lower. Some of the capacitors are fixed while others are switched in blocks; as a result the output cannot be controlled smoothly.	Static	Lowest cost reactive compensation. Capacitor banks costs range from $1 million for 50 MVAr at 115 kV to $5 million for 200 MVAr at 500 kV.

Generator or Transmission Element	Reactive Power Range	Static or Dynamic?	Cost?
Synchronous Condenser	A synchronous machine designed to supply only reactive power that consumes about 3% of capacity rating of real power from the network. Some hydro, gas turbine, and pumped storage units can operate as synchronous condensers when not generating real power.	Dynamic	The conversion costs of recent examples range from $7 to $10 million, or approximately $40,000-$50,000/MVAr.
FACTS (Flexible AC Transmission System) Devices	Use a combination of power electronic switches and switched capacitors to regulate reactive power, generally considered dynamic devices.	Dynamic	Costs are generally lower than new synchronous condensers but higher than capacitor banks. In the 115-230 kV, 0-100 MVAr inductive and 100-200 MVAr capacitive range, SVCs cost $5 million to $10 million.
Demand Response	Can impact system reactive power needs by controlling load level; behind-the meter generators may also be able to supply reactive power.	Dynamic	N/A
Hydrokinetic and Ocean Thermal	Reactive power capability is comparable to wind turbine generators. Hydrokinetic / Ocean Thermal generators can implement a control scheme similar to Type I, II, III, or IV wind turbine generators.	Static or Dynamic	Depends on design
Transmission Lines	Transmission lines produce or consume reactive power depending on the amount of power flowing on the line and the length of the line. Heavily loaded transmission lines use reactive power, while lightly loaded lines produce reactive power. Longer lines use more reactive power than shorter lines.	N/A	N/A

Almost all bulk electric power in the United States is generated, transported and consumed in an alternating current (AC) network. Elements of AC systems produce and consume two kinds of power: real power (measured in watts) and reactive power (measured in volt-amperes reactive, or vars). Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports voltages that must be controlled for system reliability. Reactive power supply is essential for reliably operating the electric transmission system. Inadequate reactive power has led to voltage collapses and has been a major cause of several recent major power outages worldwide. Reactive power can also substantially improve the efficiency with which real power is delivered to customers. Increasing reactive power production at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket.

II. Generator Reactive Power Capability Curves

A synchronous generating unit consists of a synchronous generator and a turbine. Generators have a reactive capability curve that represents the tradeoff between real and reactive power production, which is limited by heating limits of different parts of the electrical generator and the mechanical limit of the turbine. This curve is called a “D curve” because it is shaped like the letter D. An example D curve is shown in Figure 1 below. The size of the turbine determines the maximum real power the generator can produce, while the size of the synchronous generator determines the maximum reactive power. Traditionally, the turbine and synchronous generator have been matched in size so that the generator can continuously produce reactive power in the required power factor range of 0.95 leading (consuming) and 0.95 lagging (supplying) without backing off its real power. This power factor range corresponds to producing or absorbing an amount of reactive power up to approximately 30% of real power capacity.

The first step in conversion of wind energy to electrical energy results in asynchronous electricity since the electricity produced is not synchronized with the AC grid. Wind generators use a machine, known as an induction machine or asynchronous machine, to convert wind energy into electrical energy. Similarly, solar photovoltaic generators use semiconductors to convert sunlight to electrical energy that is not synchronized with the AC grid. These asynchronous wind or solar generators are connected to power converters that convert the electrical output of the asynchronous generator to synchronized AC power that can be transmitted on the transmission system. Power converters have power electronic equipment, and can be designed to mimic the reactive power characteristics of a synchronous generator. This equipment is normally installed to regulate voltages within a wind or solar facility, but can also be designed to provide reactive power support to the transmission system. Early versions of wind generators, known as Type I/II generators, had less sophisticated power converters and absorbed reactive power from the transmission system. More recent wind generator designs, known as Type III/IV generators, based on doubly-fed induction generators, have power converters that allow the wind generator to absorb or produce reactive power in response to a control signal.

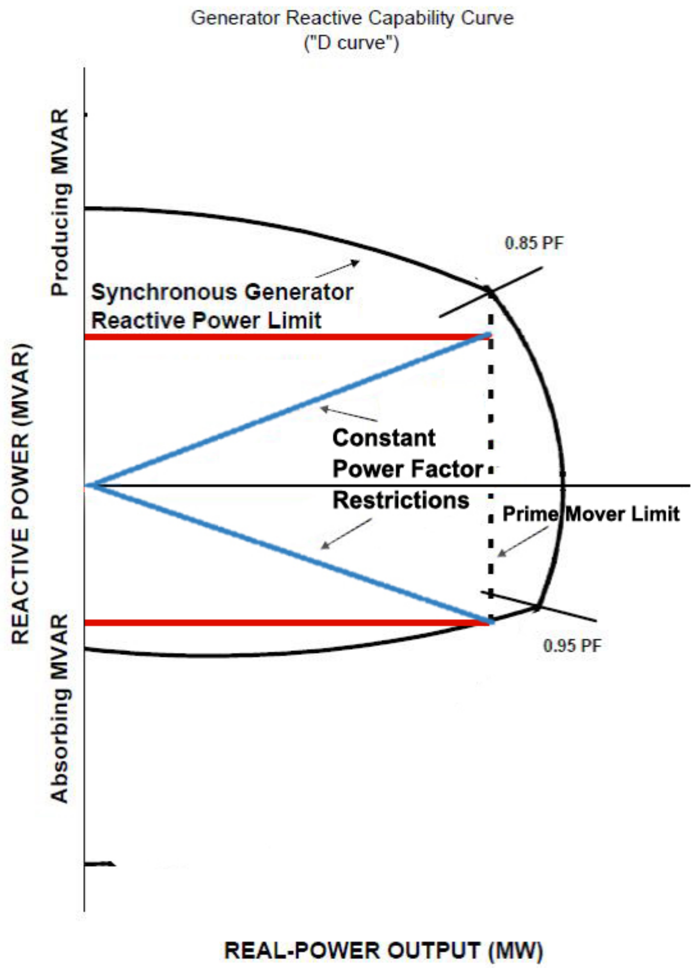

Figure 1: Synchronous Generator Capability Curve ("D curve")

Appendix 2: Cost of Reactive Power Equipment

This appendix provides details of the cost of reactive power from different types of equipment.

I. Synchronous Generators

Reactive power is produced inherently by synchronous generators. The AEP methodology, discussed in the body of the report, is the method the Commission has approved to allocate a portion of the capital costs of a synchronous generator to reactive power production. The range of rates that transmission providers charge for reactive power in OATT Schedule 2 (summarized in Appendix 3 of this report) is another indicator of the cost of reactive power from synchronous generators.

II. Wind Generators

AWEA indicates that Vestas, GE and Siemens captured about 70% of the market share of wind turbines sold in the US for the period of 2010 through 2012.[52] Our review shows that GE predominantly offers a Type III turbine, and Siemens offers a Type IV turbine. Both vendors offer inherent dynamic reactive power capability measured at the generator terminals equal to or better than 0.95 leading/lagging. One of the contributing factors to this inherent capability may be vendors finding it more cost effective to develop a standard turbine/convertor design that meets global market demand. Since there are many regions outside the Eastern and Western interconnections that require some inherent dynamic reactive power capability (e.g. Canada, ERCOT, Europe), the cost savings from providing a wind turbine design without dynamic reactive power capability may not offset additional costs associated with development, manufacturing and support of multiple product lines.

[52] American Wind Energy Association, U.S. Wind Industry Annual Market Report Year Ending 2012 Executive Summary, page 15 (2012), *available at* http://awea.files.cms-plus.com/images/AWEA_USWindIndustryAnnualMarketReport2012_ExecutiveSummary.pdf.

A report on the cost of wind energy by the National Renewable Energy Laboratory (NREL)[53] presents wind turbine capital costs and other component costs for U.S. wind projects in 2010. These costs are estimates based on a common on-shore wind turbine size of 1.5 MW, which contains an asynchronous generator.

NREL used its Wind Energy Cost and Scaling Model to estimate reference turbine costs for turbine components and balance of station areas by inputting values for specifications such as turbine rating, hub height, rotor diameter, and wind characteristics. The three major component cost categories in the NREL model are: turbine (wind turbine components), balance of station (e.g., permitting, transport, assembly, installation), and soft costs (e.g., insurance, construction finance).

NREL modeled turbines consisting of a drivetrain design with a 3-stage planetary/helical gearbox feeding a high-speed asynchronous generator. From the table below, the costs of the asynchronous generator represent approximately 4% of the installed capital cost. Recall that reactive power can be produced or consumed by asynchronous generators. These types of generators have power converters that are designed to regulate voltages within the wind project and provide reactive power support to the transmission system.

Similarly, Dr. John Coultate from Romax Technology, Ltd,[54] finds that the cost of a converter represents 4% of the capital costs of a typical wind turbine project.[55]

Another author, Willey, states that the cost of the converter represents 5% of the capital costs of a typical wind turbine project.[56]

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[53] National Renewable Energy Laboratory, *2010 Cost of Wind Energy Review* (Apr. 2012), *available at* http://www.nrel.gov/docs/fy12osti/52920.pdf.

[54] Romax Technology, Ltd is a consulting firm, based in Nottingham, United Kingdom that specializes in wind turbine drive train design, simulation, testing and monitoring solutions.

[55] Dr. Coultate, *Understanding Costs for Large Wind-Turbine Drivetrains* (Mar. 2012), *available at* http://www.windpowerengineering.com/design/mechanical/understanding-costs-for-large-wind-turbine-drivetrains/

[56] Willey, L., "Design and development of megawatt wind turbines," Wind power generation and wind turbine design, p. 248 (2010), *available at* http://books.google.com/books?id=wU9bgvrl4rQC&printsec=frontcover&source=gbs_ge_summary_r&cad=0.

Table 3 below summarizes data used for the cost of reactive power equipment found in wind generators. It is important to note that the data was derived from multiple sources, each consisting of a unique set of assumptions and parameters. For example, data from NREL's 2010 report shows that the cost of reactive power equipment is roughly 4% of total capital cost. However this value does not make a distinction between the cost of the generator and the converter (the component providing reactive power capabilities) used in their model. In addition, the cost of reactive power equipment, in USD, could only be obtained from NREL's 2010 report. As a result, a conclusion or trend observation cannot be drawn from the data summarized in Table 3.

Table 3: Summary of Cost of Reactive Power Equipment Data for Wind Generators

Source	**Cost of Reactive power equipment as % of total capital costs**	**Cost of reactive power equipment**	**Comments**
NREL (2010)	3.9%	$25.5 Million	Cost of generator (converter included)
Romax (2012)	4%	N/A	Cost of converter
Tong (2010)	3.18%	N/A	Cost of converter

III. Solar Photovoltaic Generators

Solar photovoltaic generators use equipment very similar to type IV wind generators. At the April 2012 Conference, CAISO claimed that the cost of adding reactive power in the 0.9 leading to 0.95 lagging power factor range to a solar photovoltaic plant is about 10 percent of the cost of the converter, or 2 percent of the overall project cost.[57] First Solar claimed that inverters account for 10-20 percent of the total project cost, depending on project size, and that if providing reactive power requires everything to be up-sized by 10 percent, then reactive power accounts for about 2 percent of overall project cost.[58] However, First Solar further noted that installing a fast-acting reactive power device, such as a STATCOM, is more costly.

[57] April 2012 Conference transcript at 141-142, Docket No. AD12-10.

[58] *Id*. at 157.

IV. Synchronous Condensers

One method of providing reactive power is to convert an existing conventional generator, often one that is retiring, into a synchronous condenser. The conversion involves decoupling the turbine from the generator, installing a starting means for the condenser (i.e., an on-site diesel generator), installing a new control system and making minor mechanical modifications to the generator. Conversion costs will typically also vary with the size of the generator and the number of units being converted (i.e., a five unit facility will typically require fewer than five on-site diesel generators to start the condensers).[59]

Two recent examples of conversions from a generator to a synchronous condenser are the Huntington Beach Units 3 and 4 in California and ATSI/First Energy's conversion of its Eastlake Units 1-5 and Lakeshore Unit 18.

On November 9, 2012, AES Huntington Beach, L.L.C. and the California ISO filed a Reliability Must-Run (RMR) agreement with FERC. According to the filing, Huntington Beach Unit 3 and Unit 4 are each capable of providing up to 145 MVAr (290 MVAr total) of leading or lagging capability and the total conversion cost will be approximately $14.3 million ($5.5 million per unit plus new controls, construction costs, parts and sales tax), or approximately $50,000/MVAr.[60]

On July 16, 2012, First Energy Generation Corp. (First Energy) and American Transmission Systems, Incorporated (ATSI) filed an application requesting Commission authorization for First Energy's transfer of certain generation assets to ATSI for the purpose of conversion to synchronous condensers to support the ATSI transmission system.[61] First Energy proposed to transfer to ATSI six units, Eastlake Units 1-5 and Lakeshore Unit 18 capable of providing up to 1,385 MVAr of dynamic reactive voltage

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[59] http://www.ge-energy.com/content/multimedia/_files/downloads/Converting_Existing_Synchronous_Generators_into_Synchronous_Condensers.pdf

[60] *AES Huntington Beach, L.L.C.*, Tariff Filing, Docket No. ER13-351-000, at Rate Schedule FERC No. 2 pp. 79 and 177 (filed November 9, 2012).

[61] *FirstEnergy Generation Corp. and American Transmission Systems, Incorporated*, Application For Authorization Under Section 203 of the Federal Power Act, Request For Expedited Action And Request For Waivers (ATSI Application), Docket No. EC12-119-000 (filed July 16, 2012).

support post-conversion with an estimated conversion cost of approximately $60 million, or about $43,000/MVAr.[62]

V. Static Var Compensators (SVC)

One example of an SVC installed on the high-voltage power grid is the SVC that was installed at Allegheny Power's Black Oak substation near Rawlings, Maryland in 2007. This project was initiated as part of PJM's Regional Transmission Expansion Plan and was designed to enhance the reliability on Allegheny Power's 500kV Hatfield-Black Oak-Bedington transmission line – one of the most heavily-loaded (and, at that time, most congested) lines in PJM by quickly changing reactive power levels to control the line's voltage. The SVC interconnects to the 500kV line and is able to provide reactive power in a range of 145 MVAr inductive to 575 MVAr capacitive (-145/+575) and was installed at a cost of approximately $50 million, or approximately $87,000/MVAr (capacitive).[63]

According to PJM's April 2012 reliability update, the estimated cost of building a 600 MVAr SVC at the Meadow Brook 500kV substation is $60 million ($100,000/MVAr);[64] the estimated cost of a 250 MVAr SVC on the 230 kV system is $43 million;[65] the estimated cost of a 100 MVAr fast switched shunt and 200 MVAr shunt at Mansfield 345 kV is $6.1 million;[66] the estimated cost of a 500 MVAr SVC at Hunterstown 500 kV

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[62] *Id.* at 7-8. While the Commission approved the transaction, ATSI is required to file a rate case under FPA Section 205 where it must justify any conversion costs (in addition to the transfer price, etc.) that it wants to include in its Schedule 2 for these units. So the actual incurred (and allowed) costs may differ from the $60 million figure, which is an estimate. *See FirstEnergy Generation Corp. and American Transmission Systems, Incorporated*, 141 FERC ¶ 61,239, at P 30 (2012).

[63] *See* http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/d324da10fbb8312dc12577450024daa7/$file/Black%20Oak%20SVC_A02-0207%20E.pdf. *See* ATSI Application at note 11 for cost data. *See also* http://www.energycentral.com/gridtandd/gridoperations/news/vpr/4039/ABB-Commissions-World-s-Largest-SVC-for-Allegheny-Power

[64] PJM, April 12, 2012 Reliability Analysis Update, p. 89, *available at* http://www.pjm.com/~/media/committees-groups/committees/teac/20120412/20120412-reliability-analysis-update.ashx.

[65] *Id*. at 152.

substation is $82 million.[67] In comparison, the estimated cost of a 90 MVAr capacitor bank at the Frackville 230 kV Substation is $3M.[68]

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[66] *Id*. at 153.

[67] *Id*. at 159.

[68] *Id*. at 168.

Appendix 3: Details of OATT Schedule 2 Rates for Selected Transmission Providers

In the payment section of the report, Table 1 describes several transmission providers. This appendix has further details of OATT schedule 2 rates for selected RTO/ISOs that have added details for reactive power payment or qualification of non-generator resources beyond the pro forma schedule 2.

I. ISO-NE

Rate

ISO-NE operates qualified reactive resources to produce (or absorb) reactive power in order to maintain transmission voltages on the New England Transmission System.[69] These qualified resources are compensated for such reactive service under Schedule 2 of the ISO-NE OATT. Schedule 2 currently provides for reactive power compensation based on four cost components: (1) the lost opportunity cost (LOC) component, which compensates for the value of a generator's lost opportunity in the energy market when a generator that would otherwise be economically dispatched is instead directed by the ISO to reduce real power output to provide more reactive power; (2) the cost of energy consumed (CEC) component, which compensates for the cost of energy consumed by a generator solely to provide reactive power support; (3) the cost of energy produced (CEP) component, which compensates for the cost of energy produced by a generator solely to provide reactive power support; and (4) the capacity cost (CC) component, which compensates the generator for the fixed capital costs it incurs with the installation and maintenance of equipment necessary to provide reactive power.

Calculation Method

The lost opportunity cost (LOC) for generators that are dispatched down by, or at the request of, ISO-NE, or a local control center for the purpose of providing reactive power service is calculated pursuant to Market Rule 1. Qualified non-generator reactive resources are eligible for payment of the LOC if the resource is dispatched down at the request of the ISO or a local control center for the purpose of providing reactive power service. The LOC of such qualified non-generator reactive resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B of ISO-NE's OATT and filed with the Commission.

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[69] *See* ISO-NE Open Access Transmission Tariff, Schedule 2 - Reactive Supply and Voltage Control Service (2012).

The cost of energy consumed (CEC) applies to hydro and pumped storage units, as well as non-generator resources. For hydro and pumped storage generating units that are motoring at the request of ISO-NE or a local control center for the purpose of providing reactive power service, the CEC will equal the cost of energy to motor and will be calculated in each hour as the MWh of the unit times the LMP or actual energy cost. The actual energy cost applies only if motoring energy is purchased through a bilateral contract.

Qualified non-generator reactive resources shall be eligible for payment of the CEC incurred by qualified non-generator reactive resources for the purpose of providing reactive power service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such qualified non-generator reactive resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B of the OATT and filed with the Commission.

The cost of energy produced (CEP) applies to reactive resources brought on-line by the ISO or a local control center to provide reactive power service. For thermal generating units and hydro or pumped storage units, the CEP is the portion of the total net commitment period compensation (NCPC)[70] to be paid to that resource for a day that is attributed to the hour(s) during which the resource is run to provide reactive power service in accordance with Market Rule 1 and the ISO-NE operating documents.

Qualified non-generator reactive resources are also eligible for payment of the CEP incurred by qualified non-generator reactive resources for the purpose of providing reactive power service (pursuant to the authority established within written operating protocols developed under OATT Section II.B.4). The CEP of such qualified non-generator reactive resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to OATT Section II.B and filed with the Commission.

The capacity cost (CC) component of the rate is based on the "VAR CC Rate," which is established each year as of January 1 on a prospective basis for that calendar year, and is based on a base CC rate of $2.19/kVAR-yr effective January 1, 2012,[71] prorated based on the forecast peak load for the year divided by the sum of all qualified reactive resources'

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[70] NCPC is ISO-NE's term for uplift.

[71] *ISO New England Inc.*, 137 FERC ¶ 61,237 (2011).

summer seasonal claimed capability, and based on the leading and lagging reactive power available from the unit.

For qualified non-generator reactive resources, the seasonal claimed capability is calculated as 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the resource during the testing of its reactive power capability consistent with ISO-NE procedures for measurement of such capability in megawatts.

In addition, if a non-generator source of reactive power service responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the regional system plan, and is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and such non-generator source of reactive power service meets the criteria to be a qualified non-generator reactive resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, then such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission for a rate to be paid to allow such resource to recover its costs related to providing reactive power service.

Qualification Process

The criteria for becoming a qualified reactive resource for generators are: (1) the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant; (2) the generator is interconnected to the New England Transmission System, or interconnected to the distribution system but participating in the New England Markets, and is metered and dispatchable by ISO-NE or otherwise subject to operational control by ISO-NE; (3) the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by ISO-NE, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to ISO-NE and the applicable local control center; (4) the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by ISO-NE and specified in the ISO New England Operating Documents; and (5) the installation of the generator has been approved in accordance with the requirements of Section I.3.9 of ISO-NE's OATT or its predecessor or successor provisions under the New England regional transmission arrangements.

For non-generator resources, the criteria are: (1) the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a market participant; (2) the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by ISO-NE; (3) the type of dynamic reactive power equipment is within a category of equipment that has been approved by ISO-NE, with advisory input from the reliability committee; (4) the dynamic reactive power equipment is subject to the operating authority of ISO-NE and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between ISO-NE and the non-generator reactive power resource; (5) such equipment is interconnected to the New England Transmission System and metered and dispatchable by ISO-NE or otherwise subject to operational control by ISO-NE, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to ISO-NE and the applicable local control center; (6) the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by ISO-NE and specified in the ISO New England operating documents; and (7) the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the OATT or its predecessor provisions under the New England regional transmission arrangements.

II. NYISO

Rate

The NYISO calculates payments for voltage support service annually, and makes payments monthly. Suppliers that qualify to receive payments and whose generators are under contract to supply installed capacity receive one-twelfth of the annual payment calculated by the NYISO. Suppliers whose generators are not under contract to supply installed capacity, suppliers with synchronous condensers, and qualified non-generator voltage support resources receive one-twelfth of the annual payment calculated by the NYISO, pro-rated by the number of hours that the generator, synchronous condenser, or qualified non-generator provides voltage support resources.

Calculation Method

For generators and synchronous condensers, the annual payment for voltage support service is equal to the product of $3919/MVAr and the tested reactive power capacity of the generator or synchronous condenser. For qualified non-generator voltage support resources, the annual payment for voltage support service is equal to the product of $3919/MVAr and their tested reactive power capacity as determined pursuant to the ISO procedures.[72] If a synchronous condenser or qualified non-generator voltage support resource energizes in order to provide voltage support service in response to a request from the NYISO, the NYISO compensates the facility for the cost of energy it consumes to energize converters and other equipment necessary to provide that service.

When the NYISO directs the generator to reduce its real power output below its economic operating point in order to allow the generator to produce or absorb more

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[72] *New York Indep. Sys. Operator Inc.*, 117 FERC ¶ 61,137 (2006).

reactive power, the generator receives a payment for lost opportunity costs (LOC). The LOC payment is calculated as the maximum of zero or the difference between: (1) the MW of the generator's output reduction (in order to produce or absorb additional reactive power) multiplied by the real-time location-based marginal price at the generator bus; and (2) the generator's energy bid for the reduced output of the generator multiplied by the time duration of reduction in hours or fractions thereof.

Qualification Process

To qualify for payments, a voltage support service supplier must be able to: produce and absorb reactive power within its tested reactive capability range; maintain a specific voltage level under both steady-state and post-contingency operating conditions, subject to the limitation of its tested reactive capability; automatically respond to voltage control signals; for a generator, a functioning automatic voltage regulator (AVR) is required; be under the operational control of the NYISO or a transmission owner; and successfully perform reactive power capability tests in accordance with the procedures described in Section 3.6 of the NYISO ancillary services manual.[73]

If the resource is precluded from running in "lead" mode in which it can absorb reactive power, then the unit is not eligible to provide voltage support services. However, the requirement to absorb reactive power may be set aside by the NYISO with input from the transmission owner in whose transmission district the resource is located. To grant an exemption from the requirement that the resource be able to absorb reactive power, the NYISO shall have determined that: (1) the resource is unable, due to transmission system configuration, to absorb reactive power; (2) the ability of the resource to produce reactive power is needed for system reliability; and (3) for purposes of system reliability the resource does not need to have the ability to absorb reactive power.

III. PJM

Rate

PJM determines the amount of reactive supply and voltage control that must be supplied by the transmission provider with respect to the transmission customer's transaction based on the reactive power support necessary to maintain transmission voltages within limits that are accepted and adhered to by the transmission provider. The transmission provider administers the purchases and sales of reactive supply and voltage control with PJM designated as a counterparty. Market sellers that provide reactive services at the direction of PJM are credited for such services. Generation or other source owners that

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[73] *See* NYISO Ancillary Services Manual, Section 3 – Voltage Support Service (2013).

provide reactive supply and voltage control are paid monthly by the transmission provider, equal to the generation or other source owner's monthly revenue requirement as approved by the Commission.

Calculation Method

The generator or other source owner's monthly revenue requirement is generally calculated using the AEP methodology, and filed with the Commission.

In addition to the capability payment, PJM also pays market sellers that provide reactive services at the direction of PJM, based on the difference between locational marginal price and the unit's offer price, depending on whether the active energy output of a market seller's resource is reduced or raised.[74]

In addition, if a market seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode is not committed to operate in the day-ahead market, but is directed by PJM to operate solely for the purpose of maintaining reactive reliability, it will be credited in the amount of the unit's offered price for start-up and no-load fees. The unit will also receive, if applicable, compensation based on the difference between LMP and the unit's offer price.

Finally, to the extent a synchronous condenser operates to provide reactive services and provides synchronized reserve, a market seller will be credited for providing synchronous condensing in an amount equal to the higher of (1) the hourly synchronized reserve market clearing price for each hour a generating unit provides synchronous condensing, multiplied by the amount of synchronized reserve provided by the synchronous condenser or (2) the sum of (a) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (b) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time locational marginal price at the generating unit's bus, (c) the generating unit's startup-cost of providing synchronous condensing, and (d) the unit-specific lost opportunity cost of the generating resource supplying the increment of synchronized reserve, as determined by the office of the interconnection in accordance with procedures specified in the PJM manuals.

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[74] See PJM Open Access Transmission Tariff, Schedule 2 - Reactive Supply and Voltage Control from Generation or Other Sources Service, section 3.2.3B of Appendix to Attachment K (2013).

Qualification Process

The PJM tariff does not include a specific qualification process for reactive power compensation, nor a qualification process or specific compensation formulas for non-generator sources.

IV. MISO

Rate

MISO determines the amount of reactive supply and voltage control that generation resources or other services must supply based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power range that are generally accepted in the region and consistently adhered to by MISO. MISO arranges this service with the local balancing authorities that acquire the service for MISO's transmission system.

MISO calculates rates for the service for each pricing zone, which represent a pass through of costs, based on the annual cost-based revenue requirements or cost-based rates of qualified generators. Qualified generators file their annual cost-based revenue requirement and/or cost-based rates for voltage control capability with the Commission. MISO collects a charge from each transmission customer monthly by multiplying the applicable rate by the transmission customer's reserved capacity. MISO provides each qualified generator monthly a *pro rata* allocation of the amount collected based upon the qualified generator's share of the rate within its pricing zone.

Calculation Method

MISO distinguishes its calculation of rates between service provided for load within the transmission system and for transactions exiting the transmission system. MISO determines the rate for service within the transmission system by summing the annual revenue requirements for voltage control capability, using this sum to determine the monthly reactive power revenue requirement for the pricing zone and then dividing this amount by the rate divisor for each pricing zone.[75] MISO states that any qualified generator seeking compensation for reactive service must file with the Commission to justify its cost-based revenue requirements. For qualified generators with a cost-based rate schedule on file with the Commission that does not include an annual revenue requirement, the above calculated amount is added to the stated rate. For transmission customers with loads located outside the transmission system, the rate is calculated as an average of all of the pricing zones within MISO's transmission system.

[75] The rate divisor is found in MISO's Attachment O, Page 1, Line 15.

Qualification Process

To qualify as a generation resource a generator must be able to: (1) operate with its voltage regulators in automatic mode and respond to voltage schedules set forth by MISO or the local balancing authority for the pricing zone which it is located in; (2) maintain voltage support within its design limits; (3) maintain a reactive power range of 95% leading to 95% lagging at the Point of Interconnection unless otherwise stated in the generation resource's generation interconnection and operating agreement; (4) respond to changes in voltage on the system and to changes in voltage schedules if the facility is operating; (5) provide voltage control specified by MISO or local balancing authority immediately, if intra-day system conditions require additional reactive power supply to maintain reliability, or as instructed by the transmission provider prior to the operating day based on forecasted system conditions, taking into consideration the unit's operating characteristics, and whether the generation resource is not operating at the time of the request as a result of an unscheduled or planned outage. In addition, the generator must have met the testing requirements for voltage control capability required by the regional reliability council where the generation resource is located within the past five years; and must have submitted a request to MISO for qualified generator status.

V. SPP

Rate

SPP requires all qualified generators to maintain reactive supply pursuant to a voltage schedule it provides or one provided by the applicable local balancing authority. SPP does not compensate generators operating within a standard range of 0.95 leading to 0.95 lagging for supplying reactive power.

SPP compensates all existing generation owners eligible to collect charges for reactive supply connected to the transmission system under a cost-based rate schedule on file with the Commission as of October 1, 2006. Qualified generators are paid monthly based on actual usage with no true-ups. SPP will post the applicable monthly charges to transmission customers after it possesses the data necessary to calculate the charges for a transmission customer based on multiplying the applicable rate by the transmission customer's reserved capacity.

Calculation Method

SPP charges a reactive compensation rate of $2.26 per MVAr-hour, which is multiplied by the monthly amount of reactive power provided by a qualifying generator outside of the standard range[76] to calculate monthly payments to each individual qualified generator. SPP sums these payments by zone and subtracts the revenue collected for through and out transactions for a particular zone to calculate the charges to be collected per zone. Rates charged to transmission customers are based on monthly, weekly and daily time periods with on-peak and off-peak rates.

Qualification Process

To qualify as a qualified generator a generator must: (1) designate the entity that is to receive dispatch instructions and the entity to receive compensation; (2) be able to produce reactive power outside the standard range at its Point of Interconnection with the Transmission System; (3) maintain the capability to provide MWh, MVArh and voltage data, by such means of transmittal, at such intervals and at such accuracy level as SPP shall require; and (4) follow a voltage schedule and respond to dispatch instructions from SPP and/or the local balancing authority.

VI. CAISO

Rate

CAISO determines, on an hourly basis for each day, the quantity and location of voltage support required to maintain voltage levels and reactive margins within NERC and Western Electric Coordinating Council reliability standards, and requirements of the Nuclear Regulatory Commission using a power flow study based on the quantity and location of scheduled demand. CAISO issues daily voltage schedules to participating generators, transmission owners, and utility distribution companies, which are required to be maintained for reliability. All participating generators that operate asynchronous generating facilities subject to the LGIA shall maintain the CAISO specified voltage schedule if required under the LGIA, while operating within the power factor range specified in their LGIA. CAISO "shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor range.

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[76] SPP calculates the reactive power provided outside of the standard range by determining the reactive power inside the standard range that the Qualifying Generator would have had to produce or absorb to maintain a power factor of 0.95 at its actual real power output level. SPP then subtracts the absolute value of this number from the absolute value of the actual reactive power output. If the absolute value of the reactive power inside the standard range is greater than the absolute value of actual reactive power output, the total reactive power provided is zero.

Participating Generators shall receive no compensation for operating within these specified ranges."[77]

If CAISO requires additional voltage support, it shall procure this either through reliability-must-run contracts or, if no other more economic sources are available, by instructing a generating unit to move its MVAr output outside its mandatory range. "Only if the Generating Unit must reduce its MW output in order to comply with such instruction will it be eligible to recover opportunity cost…"[78]

Calculation Method

The total payments for each scheduling coordinator for voltage support in any settlement period shall be the sum of the opportunity costs of limiting energy output to enable reactive energy production in response to a CAISO instruction. The opportunity cost shall be calculated based on the product of the energy amount that would have cleared the market at the price of resource-specific settlement interval LMP minus the higher of the energy bid price or the default energy bid price. If applicable, the scheduling coordinator shall also receive any payments under any long-term contracts due for the settlement period. Exceptional dispatches for incremental or decremental energy needed for voltage support procured through exceptional dispatch will be paid the higher of: (1) resource specific settlement interval LMP, (2) energy bid price, or (3) default energy bid (if the unit was mitigated). Reliability-must-run units providing voltage support are compensated in accordance with their reliability-must-run contract.[79]

Qualification Process

Any participating generator who is producing energy shall, upon CAISO's specific request, provide reactive energy output outside the participating generator's voltage support obligation. CAISO shall select participating generators' generating units which have been certified for voltage support to provide this additional voltage support. Subject to any locational requirements, CAISO shall select the least costly generating units from a computerized merit order stack to back down to produce additional voltage support in each location where it is needed.[80]

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[77] CAISO tariff, section 8.2.3.3, Voltage Support.

[78] *Id.*

[79] CAISO tariff, section 11.10.1.4

[80] CAISO tariff, section 8.3.8