Reactive Power Requirements and Financial Compensation

Straw Proposal

August 13, 2015

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1. Executive summary

The ISO is pursuing this initiative to propose a uniform requirement for asynchronous[1] resources to provide reactive power capability and voltage regulation. This proposed new approach will replace the current system impact study approach to assess whether asynchronous resources must provide reactive capability.

Since 2010, when the ISO previously proposed a requirement for asynchronous resources, the rapid expansion of asynchronous renewable resources has resulted in high ratios of asynchronous to synchronous generation during a portion of the operating day. Renewables are rapidly displacing the conventional generating facilities that have historically provided reactive power support to maintain voltage levels required for the efficient delivery of real power to serve electric load.

As the supply of synchronous generation declines, ISO interconnection system impact studies more frequently require asynchronous resources to provide reactive power capability as a condition of interconnecting. Given the changes to the resource fleet that the ISO is experiencing, the current approach has the risk that once an asynchronous project interconnects and is in operation, the actual system conditions could be far different than the conditions the ISO studied during the interconnection process. Thus the grid is increasingly likely to have a reactive power deficiency. Modifications to the current interconnection study approach to mitigate its shortcomings would require an increase in the overall process timeline and an increase in the cost of interconnection studies.

Instead, the ISO is proposing to adopt, on a going forward basis, a uniform requirement for all resources, including asynchronous resources, to provide reactive power capability and automatic voltage control. Requiring asynchronous resources to have the capability to provide reactive support and automatically control voltage schedules at the POI is a more reliable, efficient, and equitable approach than examining this issue through a system impact study. The ISO is informed that manufacturers routinely include this capability in standard inverters used by asynchronous resources and therefore this approach creates virtually no incremental capital costs for interconnection customers.

In addition to uniform requirements, the ISO has explored whether it is appropriate to develop a financial compensation structure for reactive power capability and provision. Although the ISO continues to look for potential enhancements to the current structure of provision payments to compensate resources for the provision of reactive power, across-the-board capability compensation for all resources would create administrative confusion and complexity, and potential over-compensation, given the fact that many resources already receive compensation for this capability. Therefore, the ISO is proposing to provide the opportunity for capability payments only to new resources that demonstrate that they have not been otherwise compensated for their reactive power capability.

[1] Asynchronous resource is a generator that does not use mechanical rotors that synchronize with system frequency.

2. Stakeholder comments

2.1. Technical requirements comments

Comment: Point of Interconnection (POI) measurement issues were raised by CalWEA, CESA, and LSA. Stakeholders state that the ISO should consider additional options as to where to measure reactive power in addition to at the POI; for example at the generator's terminal and also at the inverter terminal.

> Response: The ISO proposal is consistent with FERC Order 661a, which states the voltage requirements should be measured at the POI. By measuring voltage support from asynchronous resources at the POI the ISO intends to limit the effects of hunting issues when multiple generators are attempting to control voltages at one POI. However, where more than one asynchronous resource is encountering hunting issues the ISO may allow the voltage regulation measurement at the generator terminal.

Comment: CalWEA commented that beyond-the-POI voltage regulation and reactive support option for one or more interconnecting asynchronous generators can offer numerous benefits for both the generator and the grid. However, it is not clear how such a scheme would be implemented within the ISO's existing Generation Interconnection Delivery Application Process (GIDAP) and Transmission Planning Process (TPP) frameworks from a process and technical standpoint.

> Response: The ISO will remain impartial to the development process for resources and is only concerned with meeting the technical requirements at the POI.

Comment: CalWEA and LSA comment on the proposed response times for asynchronous resources. LSA would like clarification based on the "within a cycle" dynamic response requirement. CalWEA states that imposing a one cycle response requirement on asynchronous generators would be an unreasonable burden with minimal to no benefit, and would likely result in a major cost increase for wind and solar plant inverters.

> Response: The ISO has addressed this concern in the paper and is now only proposing that the requirements for asynchronous response times be consistent with the response time for synchronous resources (typically within 1 second).

Comment: SCE requests that the ISO clarify response time associated with the proposed VAR requirement. A definition of the terms "Dynamic" and "Static" VARs that includes a response time requirement would more clearly describe the requirement.

> Response: The ISO's expectation is that new asynchronous resources would respond across the full range of their power factor requirements (dynamic and static) in a timeframe similar to a synchronous resources capability (typically within 1 second).

Comment: CESA comments that the ISO should provide further discussion on "hunting" and where this issue is identified and who traditionally bears the costs for resolving it.

> Response: Hunting may occur if multiple resources are attempting to control scheduled voltages at a common substation. This issue may or may not be identified by interconnection studies, however effects of this situation may also be noticed by ISO operators. In other balancing authorities the generating units assume the costs for resolving generating hunting issues and some regions have requirements to address hunting through voltage droop requirements. The affected interconnecting generators will be responsible for any costs associated and resources will need to work out the details of the cost burden between themselves. The ISO believes that by addressing hunting issues in a coordinated manner, the overall cost will be lower.

Comment: CESA requests that the ISO clarify that the proposed requirements do not apply to uprates, stating that modest upgrades should not subject resources to major new requirements, within reason.

> Response: The ISO is proposing that the uniform requirements will apply to uprates. As the penetration of asynchronous resources continues to grow in the ISO footprint, it becomes more and more important that these resources be required to meet these specifications to help maintain voltage. By applying these uniform requirements to uprates as well the ISO will begin to phase out the number of asynchronous resources that have not been previously providing reactive power support, thus increasing the system's voltage support capability and reducing the number of asynchronous resources leaning on others to provide that capability.

Comment: LSA requests clarification on the need for the proposed dynamic voltage response requirements.

> Response: The asynchronous resources are rapidly replacing the synchronous resources on the system. Currently, all synchronous resources provide dynamic response across their full power factor range. Asynchronous resources also have the technology to provide this capability across the full power factor range, however the ISO is only proposing to require them to provide that capability at half (.985 lead/lag power factor range). The capability for dynamic response is important to provide needed reliability in situations of fast voltage collapse events.

Comment: LSA recommends using a study-based approach to determine if dynamic voltage response is needed.

> Response: The ISO will conduct studies to determine if the full range is necessary to be required as dynamic response if there are needs identified in the resources' interconnection study. The intent of this uniform requirement proposal is to avoid repeated system impact studies.

Comment: CalWEA requested that the ISO confirm the statement made by Mr. Loutan during the stakeholder call that the voltage schedule is expected to be static and not subject to change more than once or twice in a calendar year.

Response: In the past, changes to voltage schedules were not commonly made more than once or twice a year for historical operation; however, going forward the ISO cannot guarantee that future conditions would not require additional voltage schedule changes with the additional asynchronous resources coming online.

Comment: The CPUC seeks confirmation that all synchronous generators are already required to have similar (or greater) reactive power producing capability than the new requirements for asynchronous resources.

Response: Yes, all synchronous resources are already required to provide this capability under the ISO Tariff, Section 8.2.3.3, which states: "*For Generating Units that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) power factors."* This current requirement is equivalent to the proposed requirements for asynchronous resources. A technical explanation of this equivalency is included in Section 5.2.

Comment: The CPUC seeks confirmation or clarification that it will not be necessary for existing asynchronous generators, or those currently in the interconnection queue, to have such capability.

Response: The ISO is currently proposing the requirements would need to be in place for cluster 9 resources (April 2016). The ISO is not certain how to treat resources currently in the queue. In other regions that have implemented similar requirements a simple date cutoff option was chosen. A simple cutoff date approach may provide the greatest certainty for resources in the interconnection process. Section 5.5 of this straw proposal states that the ISO is seeking feedback from stakeholders on the best approach to this issue.

Comment: SCE is concerned with oversizing of or installing extra inverters to meet market power requirements because they may produce more real power than was studied for the market resource through the interconnection process. SCE believes that an asynchronous project can be designed in such a manner as to install static mechanically switched reactive power devices (such as capacitor banks) for steady-state control to provide the reactive power needed for internal project losses to the POI and rely on dynamic response of inverters sized to coincide with the requested interconnection amount.

Response: Regardless of the size of the inverters, ISO standards do not allow production beyond the maximum MW output specified in resources interconnection study. Resource control devices would be required to limit the output of resources to their maximum studies MW output level.

Comment: PG&E is concerned that if ISO issues a voltage schedule for an aggregated resource with one Resource ID that it will not be possible to parse out which resource will respond and accordingly which resource should be compensated. As a result, PG&E requests further clarification from ISO on how it will handle communication and voltage schedules for aggregated resources.

Response: A potential method for handling communication of voltage schedules would be to require an overall voltage support requirement for each aggregation, communicated to the Scheduling Coordinators (SC). The SC would need to determine how to best coordinate the aggregation to respond to follow the required voltage schedules. This is currently not anticipated to be addressed under this initiative. The ISO believes that issues surrounding reliability requirements and performance for aggregated resources will need to be further explored as the ISO continues to develop aggregated resources initiatives.

Comment: PG&E's interpretation is that the proposed technical requirements are limited to transmission interconnected resources. Please clarify if ISO intends for the requirements to also apply to wholesale distributed generation resources and to aggregations of distributed energy resources (DERs).

Response: At this time these requirements are proposed to be applied to the transmission interconnected resources at their POI.

2.2. Financial compensation comments

Comment: PGE requests clarification on the statement, "standard inverters used by asynchronous resources creates virtually no incremental capital costs for interconnection customers."

Response: The ISO made this statement after being informed by inverter manufacturers that they are now specifying their inverter output to have the capability to supply reactive power when producing maximum output at unity power factor.

Comment: LSA points out that the payment issue will be complicated because of the structure of most power purchase agreements (PPAs). Current PPAs do not allow payment to reach some intended generator recipients because the load serving entity (LSE) buyer is the SC for most generation resources. If the generator is entitled to a payment but the LSE SC receives that payment and there is no provision in current PPAs to pass that payment through to the generator.

Response: The ISO is proposing only additional payments be eligible for new resources that have made a showing that they are not being compensated through their contracts. Therefore this concern would not be applicable to current resources that are not eligible for capability payments. For new resources eligible for payment the issue could be mitigated by including a pass through provision for these type of revenues for any payments that would otherwise be collected by the SCs. The ISO may need to develop a method to pay those resources directly.

Comment: SCE and PG&E requested clarification on how any new payments will follow the ISO's Cost Allocation Guiding Principles.

Response: The ISO is proposing that any additional payments be allocated in a manner similar to the current cost allocation for provision payments. This current cost allocation methodology assigns costs to loads based upon a Balancing Area's Measured Demand in proportion to the system-wide Measured Demand.

Comment: PG&E, SDG&E, and the Six Cities have requested that the ISO provide cost impact analysis to estimate various cost of the proposal, including the overall costs of these potential capability payments and associated costs of administering the payments.

Response: Because the ISO is no longer proposing to provide these payments to all resources the cost impact of the proposal is more uncertain. Due to the reduced scope of these potential capability payments the ISO initially expects the cost impacts to be limited in nature. The ISO plans to explore ways to potentially estimate how many new resources may seek eligibility for the capability payments.

3. Stakeholder engagement process

The ISO has developed the following schedule for this initiative.

Milestone	Date
Issue Paper posted	May 21, 2015
Stakeholder call on Issue Paper	May 28, 2015
Issue Paper comments due	June 11, 2015
Straw Proposal posted	August 12, 2015
Stakeholder meeting on Straw Proposal	August 20, 2015
Straw Proposal comments due	September 3, 2015
Revised Straw Proposal posted	September 22, 2015
Stakeholder call on Revised Straw Proposal	October 1, 2015
Revised Straw Proposal comments due	October 15, 2015
Draft Final Proposal posted	November 9, 2015
Stakeholder call on Draft Final Proposal	November 19, 2015
Draft Final Proposal comments due	December 3, 2015
Board of Governors meeting	February 3-4, 2016

4. Background

4.1. Purpose

Electric power that flows on transmission and distribution lines is composed of two components: real power and reactive power. Real power is measured in watts (W) and reactive power is measured in volt amps reactive (VAR). Real power serves electric loads and is optimized through the ISO energy markets. Reactive power maintains voltage levels, enables real power to serve electric load efficiently and is dispatched to maintain a voltage schedule. Real power and reactive power function in an integrated, interdependent, and inseparable manner in a modern, widespread alternating current (AC) electric grid.

Because of this interdependency, an AC electric system must have the right amount of reactive power to support the delivery of real power. Conventional synchronous generation resources are the primary source of reactive power on the transmission system. Insufficient reactive power on the interconnected grid will cause unstable conditions that jeopardize delivery of power to end-use customers. A mismatch in the amount of reactive power needed will degrade the ability for any generation resource, including renewable resources, to operate. Adequate reactive power is therefore fundamental to the operation of generation resources. Without adequate supplies of reactive power, the electric grid may malfunction or even catastrophically fail due to voltage collapse. Likewise, without the capability to absorb reactive power, voltage levels can exceed acceptable operating limits causing equipment to trip off line.

Virtually any properly equipped generating facility can supply reactive power to the system, as supplemented by transmission equipment. All synchronous generators - resources with a mechanical motor that rotates synchronized with the system frequency - in the ISO produce and absorb reactive power and maintain a voltage schedule set by the Participating Transmission Owner (PTO) or ISO. Examples of synchronous generators include nuclear power plants, hydro plants and natural-gas fired generators such as peaking units and combined cycle units.

The shift to sustainable and renewable energy sources such as solar, wind, and energy storage is increasing the proportion of generators on the system that do not use mechanical rotors rotating synchronized with the system. These are asynchronous resources and do not inherently have reactive power capability unless this capability is included as an integrated feature through adding inverters, capacitors, or other means. When asynchronous resources go through the ISO interconnection study process, they may be required to provide reactive power based on a study of the expected system.

Because generation resources are the primary source of reactive power on the transmission system, the proliferation of asynchronous resources in conjunction with the retirement of large synchronous generators closer to the load centers is significantly changing the landscape of the interconnected power grid. As the need for and location of reactive power resources changes because of future additions of asynchronous resources and previously unplanned requirements, it will become necessary for reliability for all interconnected resources to provide reactive power.

Table 1 below shows the actual/expected increase in variable energy resources (VERs) through 2024.

Figure 1: Actual/expected variable energy resources within the ISO footprint through 2024 (MW)

	2011	*2012*	*2013*	*2014*[2]	*2024*[3]
Large Scale Solar PV	182	1,345	4,173	4,512	7,663
Small Solar PV[4]					3,564
Solar Thermal	419	419	419	1,051	1,802
Wind	3,748	5,800	5,894	5,894	7,028
Total	4,349	7,564	10,486	11,457	20,057

In addition to generators providing reactive power, the ISO may determine reactive power is needed in a localized area for reliability. In this circumstance the ISO may procure reactive power either through a transmission asset or through a Reliability Must Run (RMR) contract with a generator.

4.2. Current reactive power capability and provision

Similar to real power, the ISO must ensure that there is sufficient reactive power from a planning perspective and from an operational perspective. In the planning horizon, the ISO conducts studies to ensure that there is sufficient physical “steel in the ground” reactive power capability. This is similar to real power capacity planning. In the operations horizon, the ISO must ensure that the voltage of the grid is stable and there is sufficient reactive power provision in real-time. This is similar to the optimization and operations rules to maintain the ISO energy market.

The ISO studies the need for reactive power capability in three main groups of studies; the (1) Generation Interconnection Process (GIP) studies, (2) TPP studies, and (3) Annual Local Capacity Technical Studies. The GIP study will determine whether the studied *market resources* requesting interconnection to the grid must provide reactive power capability and will also identify the need for network upgrades required to provide reactive power capability.[5] The TPP

[2] Values for 2011-2014 are from: https://records.oa.caiso.com/sites/mqri/Records/Renewable%20Daily%20Watch/2014%20Renewable%20Watch/12-2014%20Renewable%20Reports/20141229_DailyRenewablesWatch.pdf

[3] Values for 2024 are from: http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf (Table 9)

[4] Less than 20 MW and connected to the ISO controlled grid.

[5] Non-participating generators are also assessed in the interconnection process; however, these resources do not participate in the CAISO and are subject to separate rules.

study will determine whether additional reactive power capability is needed, accounting for all existing and future approved reactive power devices and resources. If additional reactive power capability is required according to the TPP study, the ISO will identify the most effective and efficient *transmission asset* to provide reactive power. The Annual Local Capacity Study finds the minimum resource adequacy capacity needed to meet the Local Capacity Requirements criteria including reactive power needs. In very rare circumstances there may be no capacity available in the local area to meet the requirement and the ISO may procure resources under a RMR contract. The ISO may also perform ad hoc operational reactive power capability studies that result in an RMR contract; however, these studies are done infrequently and find the need for additional reactive power capability only in highly unusual situations.

Market resources, transmission assets, and resources under RMR contracts all provide reactive power capability to the grid, but each type has unique participation and reactive power provision rules. Market resources must provide reactive power within a standard range that is defined in the tariff ancillary services rules. Transmission assets and RMR resources must provide reactive power according to a resource-specific contract. The ISO has provided information in Appendix A of this straw proposal that describes each study, resource type, and participation and provision rules in more detail.

4.3. Issues with Generation Interconnection Process

The case-by-case, system impact study approach to assess whether asynchronous resources must provide reactive capability has several shortcomings.

First, system impact study may not require that every project provide reactive power capability because it may conclude there will be sufficient reactive power on the transmission system due to the capabilities of existing generators with reactive power capability and other reactive power devices on the transmission system. However, a glaring weakness with this approach is that such a study cannot reasonably anticipate all operating conditions in which resources with reactive power capability or reactive power devices on the transmission grid will be out of service – either due to retirement, or forced or planned outage –when reactive power needs arise. The case-by-case approach relies heavily on the assumptions of future conditions, which may not prove true and does not plan for unpredicted events. Once an asynchronous project is interconnected and is commercially operable, actual system conditions could be far different from the conditions studied.

System impact studies do not – and cannot within current process timelines – cover all operational scenarios or future conditions that may require a resource to provide reactive power capability.[6] Interconnection studies are time consuming and iterative in nature.[7] If the ISO studied all possible operating conditions, potential outage schedules, and potential retirements for existing resources to more comprehensively assess the need for an asynchronous resource

[6] April 17, 2012 FERC Technical Conference on Reactive Power Resources (AD12-10-000), Transcript at 20:23-21:15. http://www.ferc.gov/CalendarFiles/20120426074709-AD12-10-04-17-12.pdf

[7] *Id.* at 17:8-16.

to provide reactive power support and absorption capability, the cost and time required for the system impact study process would increase. The ISO estimates that to enhance its system impact study efforts to account for a more robust set of operating conditions would take at least another four months of study for each interconnection cluster at an additional cost of approximately $2 million for each interconnection cluster. Currently, the ISO must complete the interconnection study processes within 205 days. To study a more robust set of operating conditions the ISO must undertake roughly ten times more study work to make the interconnection system impact study comparable to the transmission planning process.

Even if the ISO completes these system impact studies in a timely and cost–effective manner, it is impractical to identify and examine all possible operation conditions. Deficiencies in reactive power support and absorption may not always occur during system peak and often can occur on days with high levels of variable energy resources and low demand periods or during periods when transmission infrastructure is out of service. In addition, a significant portion of the generating fleet is out on maintenance during the non-summer months, which places a level of subjectivity in studying off-peak operating scenarios because of the combinations of resources out on maintenance, load levels and asynchronous production levels.

If an unstudied operating condition occurs that results in unanticipated reactive power needs, then asynchronous resources unable to provide reactive power may adversely affect the voltage stability of the system. Absent sufficient voltage, asynchronous resources may face operational issues (*e.g*. wind facilities may have to operate at lower than optimal levels until they could provide voltage control even though interconnection studies did not detect voltage issues).[8] By interconnecting to the transmission system without a sufficient reactive margin at its POI, an asynchronous resource may degrade both the system and its own operations.[9]

Second, if a system impact study identifies a need for reactive power support in a queue cluster and requires asynchronous resources within that cluster to provide reactive power, these resources compensate for all earlier queued resources for which the transmission provider identified no reactive power need. This “leaning” of asynchronous resources without reactive power capability on the reactive power support of other resources and reactive power devices unfairly distributes the costs of providing reactive power. It also raises questions regarding the inequities between resources that have incurred costs to provide reactive support to the transmission system and those resources that have not, based on the mere happenstance of when they were studied.

Last, the system impact study approach potentially introduces unknown investment risks because customers with asynchronous generating projects in the ISO’s queue only learn of the need to provide reactive power during the second phase of the ISO’s interconnection studies. Applying uniform reactive power and voltage control requirements for asynchronous generating facilities provides up-front cost certainty for investors and developers. In Appendix A the ISO

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[8] *Id*. 150:24-152:16.

[9] *Id*. 43:4-18.

has provided two cases studies that illustrate the limitations of the interconnection study process.

4.4. Uniform requirement for asynchronous resources

A uniform reactive power standard enhances the reactive capabilities on the system compared to an ad hoc approach based on site specific requirements determined during interconnection.[10] North American Electric Reliability Council's (NERC's) Integration of Variable Energy Resource Task Force conducted a special reliability assessment that recommends that NERC consider revisions to reliability standards to ensure that all generators provide reactive support and maintain voltage schedules.[11] Requiring all interconnecting resources to provide reactive capability will remedy the shortcomings of the current approach and ensure distribution of the reactive power control throughout the system.[12]

4.5. Uniform requirements adopted in other jurisdictions

To ensure adequate voltage on their transmission systems, other jurisdictions have adopted a uniform reactive power requirement for asynchronous resources. For example, the Electric Reliability Council of Texas, Inc. (ERCOT) adopted a reactive power standard to integrate the build out of competitive renewable energy zones and support the transfer of that supply within the ERCOT region.[13] Specifically, ERCOT determined that imposing uniform reactive power obligations across all generation types was necessary because of challenges presented by integrating significant amounts of renewable generation in locations distant from load centers. The ISO faces similar circumstances because it is also integrating significant amounts of asynchronous resources. With ERCOT, applying a uniform reactive power standard to asynchronous resources avoided a situation in which projects interconnecting needed to wait for additional reactive power resources to compensate for unstable voltage conditions on the grid.

Other jurisdictions in North America have also adopted uniform reactive power requirements.[14] The Independent Energy System Operator (IESO) in Ontario, Canada requires renewable generators to provide reactive power continuously in the range of 0.95 lagging to 0.95 leading at the POI based on rated active power output, with no determination in system impact study. This

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[10] April 17, 2012 FERC Technical Conference on Reactive Power Resources (AD12-10-000), Written Statement of Jeff Billo at 4-6. http://www.ferc.gov/EventCalendar/Files/20120417082804-Billo,%20ERCOT.pdf

[11] NERC Specific Reliability Assessment: Interconnection Requirements for Variable Generation at 2-3: http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf

[12] April 17, 2012 FERC Technical Conference on Reactive Power Resources (AD12-10-000), Transcript at 20 at 17:7-22.

[13] April 17, 2012 FERC Technical Conference on Reactive Power Resources (AD12-10-000), Written Statement of Jeff Billo http://www.ferc.gov/EventCalendar/Files/20120417082804-Billo,%20ERCOT.pdf

[14] April 17, 2012 FERC Technical Conference on Reactive Power Resources (AD12-10-000), Transcript at 120:18-121:13.

is required for safety and/or reliability. The IESO also has voltage control requirements that apply to renewable resources.

The California Public Utilities Commission (CPUC) recently issued a decision adopting modifications to Electric Tariff Rule 21 to capture the technological advances offered by today's inverters. In Decision 14-12-035,[15] the CPUC noted that as greater numbers of renewable generating resources interconnect with the grid, the influence of inverters will grow. The CPUC further noted that today's inverters have many capabilities including:

- The generation or absorption of reactive power to raise or lower the voltage at its terminals.
- Delivery of power in four quadrants, positive real power and positive reactive power; positive real power and negative reactive power; negative real power and negative reactive power; and negative real power and positive reactive power.
- The detection of voltage and frequency at its terminals and the ability to react autonomously to mitigate abnormal conditions: to provide reactive power if the voltage is low; to increase real power output if the frequency is low.

The CPUC decision requires that inverters installed after the effective date[16] of the requirements adopted in the decision should comply with the updated standards applicable to all inverters. Although the CPUC requires that inverters meet certain requirements, the CPUC does not require that asynchronous resources install sufficient inverter capacity to meet the ISO's reactive power requirements.

In addition, PJM Interconnection recently proposed *pro forma* interconnection agreements to require that wind and non-synchronous generators interconnecting with PJM's system after May 1, 2015 meet certain voltage and frequency ride through requirements and must have the ability to provide dynamic reactive support.

On May 5, 2015, FERC issued an order conditionally accepting PJM's tariff revisions to require that prospective interconnection customers contemplating the interconnection of non-synchronous resources to autonomously provide dynamic reactive support within a range of 0.95 leading to 0.95 lagging at inverter terminals and adhere to NERC Reliability Standard PRC-024-1 regarding voltage and frequency ride-through capabilities, irrespective of resource size.[17] FERC's order finds, in part, that inverter technology has changed both in availability and in cost since the Commission rejected a similar ISO proposal in 2010. Therefore, FERC's order finds that PJM's proposal will not present a barrier to non-synchronous resources. FERC's order, however, conditions acceptance of the tariff revisions on PJM clarifying that it will only measure

[15] Issued December 18, 2014, in CPUC Rulemaking 11-09-011.

[16] The later of December 31, 2015, or 12 months after the date the Underwriters Laboratory approves the applicable standards.

[17] *PJM Interconnection LLC*, 151 FERC ¶ 61,097 (2015) http://www.ferc.gov/CalendarFiles/20150505165917-ER15-1193-000.pdf

reactive power under conditions in which a wind plant's real power output exceeds 25 percent of its nameplate capacity.

4.6. Uniform requirement ISO regulation background

In 2010, the ISO filed a tariff amendment with the Federal Energy Regulatory Commission (FERC) to adopt a uniform reactive power and voltage control requirement to large (over 20 MW) asynchronous resources seeking to interconnect to the ISO grid.[18] The ISO argued that the transformation of the electric grid justified these proposed requirements because the ISO would need the reactive power support of an increasing number of asynchronous resources to replace the reactive support provided by energy from existing synchronous resources being "crowded out" or displaced. FERC rejected the ISO's proposed tariff revisions without prejudice.[19] FERC determined that the ISO's supporting documents did not explain adequately why system impact studies are not the proper venue for identifying power factor requirements for wind generators and why the ISO had to implement a broad requirement, without confirmation of system need as verified from the appropriate system studies, applicable to all asynchronous generators.

However, the ISO has found that the system impact study approach provides no sufficient range of scenarios or time to assess reactive power needs in the context of the transformation of the ISO's resource mix. In addition, the system impact study cannot model every operating scenario such as over-generation conditions during which the ISO will need resources to absorb reactive power. The current system impact study process balances the needs of interconnection studies with an interconnection customer's needs for a timely and efficient interconnection process. Given sufficient time and resources – which translates to increased interconnection study deposits by developers and an increase in the overall process timeline – the ISO could conduct more exhaustive studies, explore significantly more scenarios, and likely make a finding in every case that a resource must provide reactive power capability to safely and reliably interconnect to the grid. Such increased costs, inefficiencies in the study process and corresponding delays to interconnecting renewable energy resources are all counterintuitive to the state and federal goals for clean energy. As such, the current interconnection study process does not afford this amount of time or resources to complete such studies. However, absent a more comprehensive level of studies to determine that all resource interconnections will meet mandated reliability standards and established practices for planning and operations, core responsibilities for assuring reliability must still be fulfilled. Accordingly at this time, the ISO believes it cannot make the finding that resources can safely and reliability interconnect to the grid without providing reactive power capability.

[18] California Independent System Operator Corporation tariff amendment in FERC docket ER10-1706 dated July 2, 2010. http://www.caiso.com/Documents/July2_2010Amendment-modifyinterconnectionreqsapplicable-largegenerators.pdf

[19] *California Indep. Sys. Operator Corp.* 132 FERC ¶ 61,196 (2010) at PP45-48; 54-55. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12426191

On rehearing, FERC determined that the ISO did not provide adequate evidence to support its assertion that wind and solar photovoltaic generators will displace synchronous resources on the ISO's transmission system in a timeframe and manner that supports the proposed tariff revision.[20] Notwithstanding FERC's determination, empirical evidence described in this issue paper and straw proposal reflects that asynchronous resources are displacing synchronous resources on the electric grid. FERC rejected the ISO's proposal to require these resources to provide reactive power capability without a demonstration of need in a system impact study. But a system impact study relies heavily on the assumptions of future conditions and does not afford sufficient opportunity to assess all operating conditions. As the ISO has observed, actual system conditions – both peak and off peak - could be far different from the conditions studied.

The ISO filed a petition for review of FERC's orders in the Court of Appeal and asked the court to hold the petition in abeyance pending the outcome of a technical conference at FERC on whether asynchronous generators should be subject to a uniform requirement to provide reactive power capability. Since holding its technical conference and soliciting comments, FERC has taken no further action in the proceeding.

Among the reasons examined in the ISO's earlier stakeholder process for not requiring asynchronous resources to provide their share of reactive requirements are : (1) inverter technology has not advanced sufficiently to reliably provide reactive and voltage control; (2) there is an abundance of reactive power and voltage control provided by synchronous generating facilities; and (3) the cost is too high and may inhibit the entry of new, asynchronous technologies (including non-greenhouse gas emitting resources).

The landscape has changed since FERC issued its orders, and the considerations identified above are no longer valid. First, modern inverter technology enables asynchronous resources to serve as a reliable source of reactive power and voltage control. Second, additional empirical evidence reflects that energy from asynchronous resources is rapidly displacing energy from synchronous resources in the generation mix with a corresponding reduction in the supply of reactive power and voltage control. Third, the cost picture has changed—some inverter manufacturers now include the capability to provide or absorb VARs as a standard feature. Only when a wind or solar resource is operating at the maximum rated output capabilities of its inverter will there be lost revenue due to providing VARs instead of MWs, assuming that the inverters are sized to provide this maximum power at unity power factor only. This may drive developers to oversize the inverter ratings of the facility, but the ISO understands this is a common practice to meet contractual output levels.

At present, FERC allows jurisdictional transmission providers to require large wind generators, as a condition of interconnection, to provide reactive support based on a demonstration in an interconnection system impact study that the system needs reactive support from the generator

[20] *California Indep. Sys. Operator Corp.* 137 FERC ¶ 61,143 (2011) at PP 10-11. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12820086

to ensure efficient and reliable operation of the transmission system.[21] FERC has also applied this rule to solar resources.[22]

5. Straw proposal

5.1. Proposed asynchronous resource requirements

The ISO proposes to adopt a uniform requirement for asynchronous resources to provide reactive power capability and voltage regulation. This primarily includes wind, solar, and storage facilities.

The ISO proposes to apply these new rules on a going-forward basis to those resources that interconnect through the Generation Interconnection Delivery Application Process (GIDAP).[23]

5.2. Proposed requirements for asynchronous generating facilities

The ISO believes that the appropriate balance between harmonizing reactive power requirements and existing customer expectations is to apply this new policy beginning with interconnection customers in the first queue cluster having an interconnection request window following the effective date of the tariff revisions. Thus, the ISO is proposing to exempt projects already in the ISO interconnection process and existing individual generating units of an asynchronous generating facility that are, or have been, interconnected to the ISO controlled grid at the same location from these new requirements for the remaining life of the existing generating unit. The ISO proposes, however, that generating units replaced or repowered, must meet these new requirements.

The ISO proposes to set asynchronous requirements equivalent to the current synchronous requirements, consistent with FERC Order 661a. Because asynchronous units typically use different technology to provide reactive power the requirements will not be identical. Instead, the ISO will set the requirements so both resource types provide reactive power equivalently.

a) An Asynchronous Generating Facility shall have an over-excited (lagging) reactive power producing capability to achieve a net power factor from 0.95 lagging up to unity power factor at the POI, at the Generating Facility's maximum real power capability.

[21] *Interconnection for Wind Energy,* Order No. 661, FERC Stats. & Regs. ¶ 31,186, at 50-52 (2005) ("Order No. 661"); *Interconnection for Wind Energy*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198, at PP 41-46 (2005) ("Order No. 661-A").

[22] *See e.g. Nevada Power Co.*, 130 FERC ¶ 61,147 (2010) at PP21-27. http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12279145

[23] New interconnection requests to the ISO grid are governed by the GIDAP approved by FERC in 2012. The GIDAP rules are contained in ISO Tariff Appendix DD.

b) An Asynchronous Generating Facility shall have an under-excited (leading) reactive power absorbing capability to achieve a net power factor from 0.95 leading up to unity power factor at the POI, at the Generating Facility's maximum real power capability.

c) Asynchronous Generating Facilities shall provide dynamic voltage response between 0.985 leading to .985 lagging at rated MW capacity at the POI as specified in Attachment 1.

d) Asynchronous Generating Facilities may meet the power factor range requirement at the POI by using controllable external dynamic and static reactive support equipment.

e) Within the dynamic reactive capability range, Asynchronous Generating Facilities shall vary the reactive power output between the full sourcing and full absorption capabilities in a continuous manner.

f) Outside the dynamic range of .985 leading to .985 lagging, and within the overall reactive capability range of .95 leading and .95 lagging, the reactive power capability could be met at full real power capability with controllable external static or dynamic reactive support equipment.

g) Should the interconnection studies show the need for dynamic reactive power within the overall reactive capability range of .95 leading to .95 lagging, then the full power factor range must be dynamic.

Stakeholders requested additional clarification about how the requirements for both synchronous and asynchronous were equivalent. This is because the proposed power factor requirements appear as different values, with different measurement locations.

To provide greater clarity around the equivalency of these standard requirements for both types of resources and their respective measurement locations, the ISO refers to NERC's 2012 Interconnection Requirements for Variable Generation report. This report states that; customarily, reactive capability of variable generation resources is specified for transmission interconnections at the POI. This is generally at the high side of the main facility transformer. Generally, a synchronous generator with reactive capability of 0.9 lag (over-excited) and 0.95 lead (under-excited) (measured at the generator terminals) connected to the transmission system through a step-up transformer with leakage reactance of 14 percent (on the generator MVA base) can provide 0.95 lag/lead at the POI.[24]

[24] NERC Specific Reliability Assessment: Interconnection Requirements for Variable Generation at 19-21: http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf.

5.3. Operational requirements for asynchronous generating facilities

When the plant real power output is at its maximum capability, the Asynchronous Generating Facility shall have the capability to provide reactive power at .95 lagging for voltage levels between .95 per unit and unity power at the POI. Likewise, the Asynchronous Generating Facility shall have the capability to absorb reactive power at .95 leading for voltage levels between unity power factor and 1.05 per unit at the POI.

2. Voltage regulation and reactive power control requirements for Asynchronous Generating Facilities:

    a) The Asynchronous Generation Facility's reactive power capability shall be controlled by an automatic voltage regulator (AVR) system having both voltage regulation and net power factor regulation operating modes. The default mode of operation will be voltage regulation.

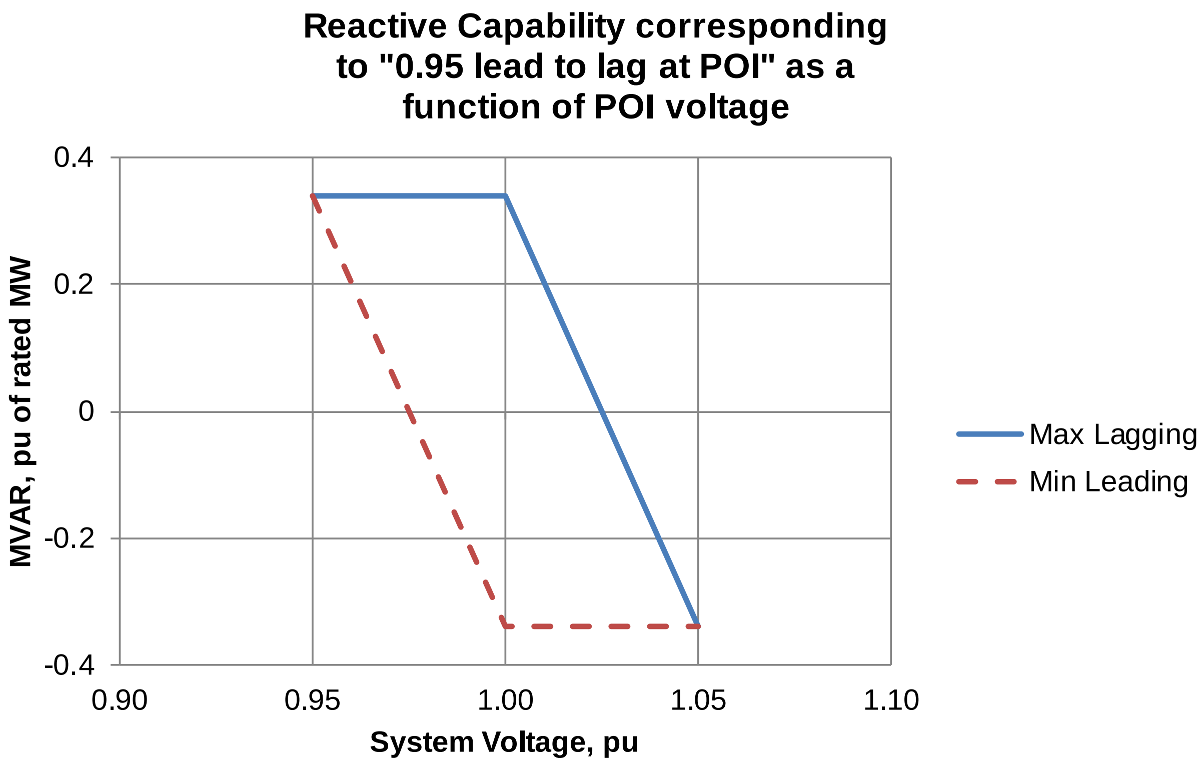
    b) The voltage regulation function mode shall automatically control the net reactive power of the Asynchronous Generating Facility to regulate the POI scheduled voltage assigned by the Participating TO or ISO, within the constraints of the reactive power capacity of the Asynchronous Generation Facility.

    c) The ISO, in coordination with the Participating TO, may permit the Interconnection Customer to regulate the voltage at a point on the Asynchronous Generating Facility's side of the POI. Regulating voltage to a point other than the POI shall not change the Asynchronous Generating Facility's net power factor requirements set forth in Section A. iii of Appendix H. (See Attachment 3).

    d) The ISO, in coordination with the Participating TO, may permit the Interconnection Customer to regulate the voltage at a point on the PTO's side of the POI. Regulating voltage to a point other than the POI shall not change the Asynchronous Generating Facility's net power factor requirements set forth in Section A. iii of Appendix H. (see Attachment 3)

    e) The Interconnection Customer shall not disable voltage regulation controls, without the permission of the ISO, while the Asynchronous Generating Facility is in operation.

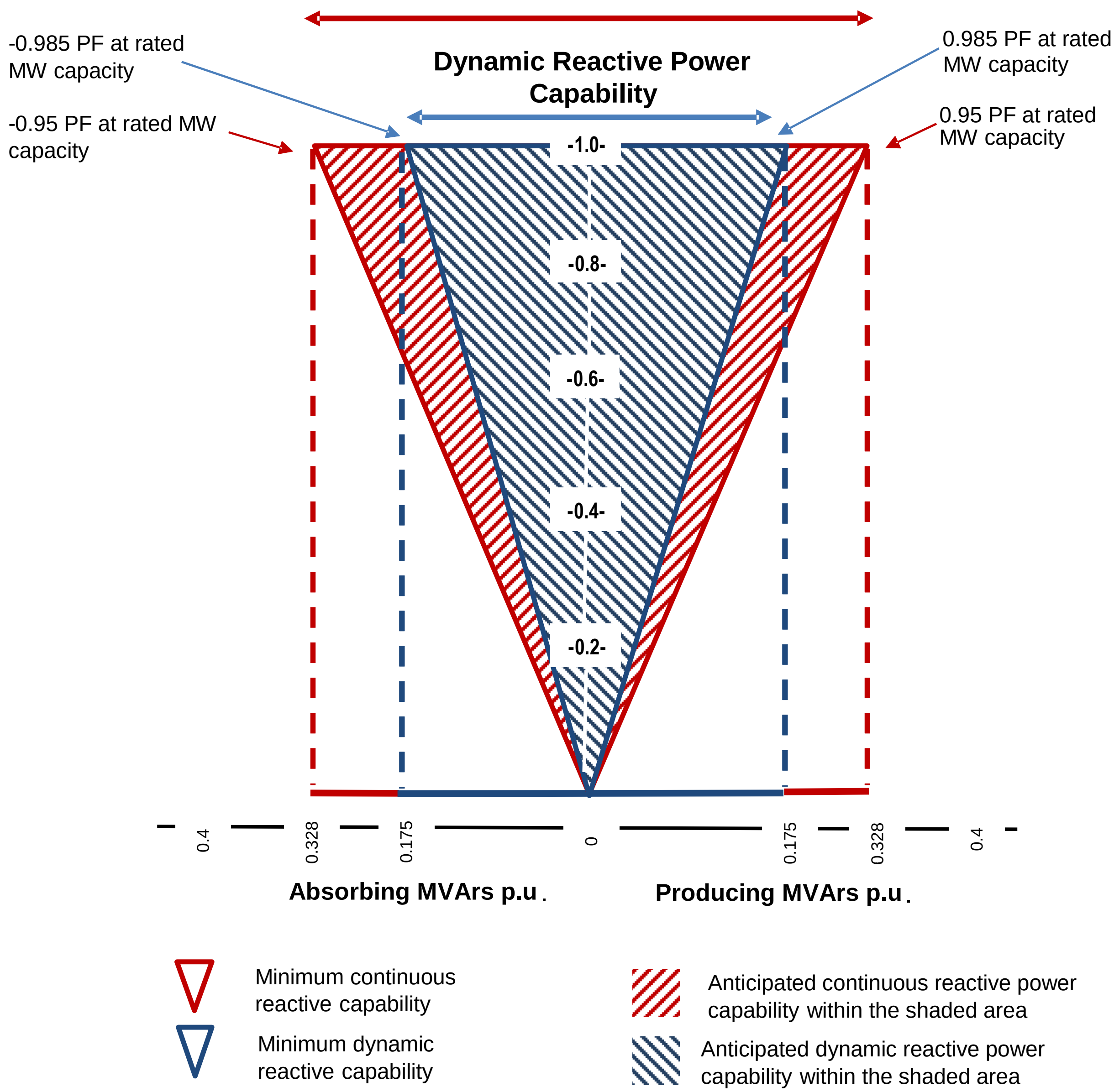
Figure 2: Proposed reactive power capability at different voltage levels



Note: The figure above specifies that when the real power output is at its maximum capability, the Asynchronous Generating Facility shall have the capability to provide reactive power at 0.95 lagging when voltage levels are between 0.95 per unit and 1 per unit at the POI. The capability to provide reactive power decreases as the voltage at the POI exceeds 1 per unit.

Likewise, the Asynchronous Generating Facility shall have the capability to absorb reactive power at 0.95 leading when voltage levels are between unity power factor and 1.05 per unit at the POI. The capability to absorb reactive power decreases as the voltage at the POI drops below unity power factor.

Figure 3: Proposed reactive power capability for asynchronous resources



Note: In the figure above, the red and blue isosceles triangles show the expected reactive capability of the Asynchronous Generating Facility at the POI. At maximum real power capability of the Facility, the expected dynamic reactive capability should be between 0.985 lagging to 0.985 leading. Also, at maximum real power capability, the overall expected continuous reactive capability should be between 0.95 lagging to 0.95 leading. As shown, as the real power output decreases both the dynamic and continuous reactive capabilities also decreases.

5.4. Uniform requirement technical issues

Hunting

Multiple asynchronous resources in close electrical proximity can cause unstable voltage control when their controls are not coordinated. Uncoordinated voltage control can also surface when two or more asynchronous resources share a common generation tie and are assigned to regulate voltage at a common POI.

The ISO's proposal should mitigate this concern by allowing asynchronous resources to control its terminal voltage. The ISO proposes to allow developers the flexibility to develop a control scheme to utilize a voltage droop function with necessary supervisory control to allow reactive power sharing among the asynchronous resources.

Finally, the ISO proposes that developers can work together and elect to control the schedule voltage at a common station beyond the POI with other plant-level reactive support equipment.

Collective generation projects

Many asynchronous resources comprise multiple devices aggregated for production at the wholesale level. The ISO proposes a uniform interconnection requirement to ensure the availability of sufficient and usable reactive capability in the operations horizon. Under the proposed reactive power requirements each resource must meet a power factor of 0.95 leading and lagging at or near the POI. Asynchronous resources may use a variety of means to meet this requirement, such as oversizing inverters, or using fast switching devices. The ISO will not discriminate based on technology aggregated within the participating resource. If all individual devices comprising an aggregated resource can meet this reactive requirement under the same participating resource, then the resources can participate in the market in any way it prefers. If the aggregated resource depends upon devices or sub-parts of the combined resource to meet this requirement, it must be dispatched under a single Resource ID in the market.

The ISO proposes to allow any collective generation project to participate in the market however it sees fit, provided that the resource can fully meet this requirement thus ensuring visibility, reliability, and availability of the reactive capability in the operations horizon. This proposal should serve as a universal planning requirement that ensures the availability of sufficient reactive capability in the operations horizon. Allowing a resource to participate in the market without this capability circumvents this process and creates the possibility of a generation dispatch and power transfer scenario in the operations horizon not reviewed via the planning process. Further any reactive power capacity payment made to a resource that can schedule or bid parts of the resource which do not meet the requirement circumvents the reactive capability the payment is meant to procure.

Metering and telemetry

All resources participating in ISO markets must execute a meter service agreement and have ISO meters. There are no exemptions for size or unit type. The Metering BPM, appendix B, outlines technical specifications required for these meters. These include reactive power metering requirements.

Generating Units connected to the electric grid within the ISO balancing authority area (BAA) must install telemetry equipment and/or software that can interface with the ISO's Energy Management System (EMS) to supply telemetered real-time data

These rules apply to all resources that:

(1) have a capacity of ten MW or greater, or

(2) provide Ancillary Services, or

(3) are Eligible Intermittent Resources

The BPM for telemetry defines reactive power telemetry requirements. Resources must provide MVAR value at the point of delivery (POD/POI) - where the unit connects to the ISO controlled grid. POD MVAR establishes reactive power delivery to the system and the impact on system voltage. This value may be obtained by installing instrument devices at or on the unit side of the POD. It can be calculated by providing an accurate conversion of another data point measured at the same voltage level as the POD. The value must represent an accuracy of +/-2% of the true value of POD MVAR represented in the ISO revenue meter.

Inverter size

During the Interconnection Request (IR) validation process, the ISO validates that the generating resources net MW equal gross MW minus auxiliary load. The gross MW is the total installed capacity of the inverters. When inverters are used to provide reactive power, we ask the interconnection customer to note that the gross MW is a lower number than nameplate MW, which is at unity power factor.

Item 2A[25] of the Interconnection Request asks for the Total Generating Facility rated output (MW) that represents the gross output number at the generator terminals. Typically, the inverter MW capacity provided by the manufacture is at unity power factor. The MW capacity under a different power factor is lower than that under unity power factor. If the Interconnection Customer uses inverters to meet the reactive power capability requirement, the ISO requests that the MW capacity and the associated power factor is indicated on the form.

The ISO proposes that we explicitly change the Interconnection Request form to include both MVA rating and MW rating for inverter based generators for ease of compliance verification.

The Generator Management BPM, section 3.5.4.1, describes how the ISO evaluates inverter changes that would cause a capacity increase greater than the project net capacity listed in the Interconnection Customer's interconnection request. However, at no time may the Generating Facility's inverter configuration increase the project's net capacity by more than the greater of:

[25] https://www.caiso.com/Documents/SampleInterconnectionRequest-TechnicalData-Solar-Wind.pdf

- ten percent (10%); or
- three (3) MW

One stakeholder submitted a comment appearing to express concerns that this limitation would prohibit a generation project from meeting the 0.95 lead/lag reactive power requirement if a resource voluntarily provided reactive power. During the stakeholder meeting the ISO explained that a generator that increased its inverter capacity by 5.2% could improve its power factor capability from a 1.0 power factor to a 0.95 lead/lag power factor, which is within the 10% limit.

Inverter cost

The cost of including reactive power capability as a percentage of project costs is relatively small.[26] Some entities contest this fact and argue that applying a uniform reactive power requirement to asynchronous resources creates significant capital and operational costs.[27]

The ISO recognizes the possible concern that a uniform requirement for asynchronous resources to provide reactive power capability and voltage regulation could impose higher inverter costs on those projects that would otherwise avoid such requirements through the system impact study approach currently in use. In this context the ISO conducted outreach with inverter manufacturers such as General Electric and Siemens to learn more. The ISO found:

- Approximately 5 percent of total plant cost is attributable to inverters and associated equipment (e.g., transformer, controller). This is a sunk cost because all asynchronous resources must have inverters. Given the sunk costs, the incremental costs for adding reactive power capabilities are less.
- Reactive power capability is now a standard feature of inverters used in both wind and solar PV applications and there is no additional cost for reactive power capability. Typically, these inverters can provide 0.95 leading and lagging power factor at full real power output at the POI.

Based on these observations, the ISO believes the additional costs, if any, due to a uniform requirement would likely be *de minimis*.

5.5. Uniform requirements implementation timing

The ISO is exploring the best methods for applying these reactive power requirements as it implements this initiative. There are important considerations related to the timing of implementation. There is an imperative need to apply these requirements quickly due to the influx of considerable levels of asynchronous resources on the system. At the same time, the

[26] *Id*. at 141:10-124:6.

[27] *See e.g.* Comments of the American Wind Energy Association in response to the April 22, 2014 workshop on Third Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services filed in FERC Docket AD 14-7 at 7-8. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13567273

ISO understands that resources need certainty on the requirements they will be obliged to meet while designing and contracting.

The ISO is currently proposing the requirements would need to be in place for cluster 9 resources (April, 2016). It remains unclear how to treat the application of these requirements for resources currently in the queue. Other regions that have implemented similar requirements utilized a simple date cutoff option was chosen for which all resources coming online after that date would need to meet the new requirements. This date cutoff approach may provide the greatest certainty for resources in the interconnection process.

The ISO wishes to discuss these issues with Stakeholders and seeks feedback on the best methods for the timing of implementing these requirements and treatment of resources in the queue.

5.6. Financial compensation

Purpose and summary

The ISO recognizes that market resources incur fixed and variable costs to provide reactive power as opposed to real power.[28] In other regions, FERC has accepted that reactive power payments are just and reasonable, but has required that these payments reflect the actual costs of providing reactive power.

Through this initiative, the ISO is exploring the potential to provide an ISO administered payment structure to allow the recovery of generator-specific or technology-specific capital costs in conjunction with requiring reactive power requirements for all interconnected resources. Factors that the ISO has reviewed include current payment structures in place in the ISO and other regions, comparisons of the various ISO/RTO market constructs, and evaluation of related regulatory decisions. After careful consideration, the ISO is proposing to recommend additional compensation mechanisms for reactive power capability for new resources that have also made a showing that contractual agreements specifically lack any compensation for their fixed costs associated with reactive power equipment.

Regulatory review

Some ISO/RTOs provide financial compensation for the capability and/or provision of reactive power; however the payments and cost recovery methods vary by region. Some ISO/RTOs only pay for the provision of reactive power. Payments for reactive power can be similar to real power in that there are potentially two types of revenue streams. These are roughly equivalent to capacity and energy payments for real power in some markets. Provision payments are generally offered to cover resources variable costs for providing reactive power outside of a standard required range. Additionally, capability payments have been used in some markets to cover the fixed costs of a resource's equipment installed for the capability to provide reactive power. While some regions pay both types of payments, others only pay for the provision of

[28] Market resources as distinguished from transmission assets or resources under RMR contracts as described in section 4.2.

reactive power due to their market design, resource adequacy constructs, and utility procurement practices.

The main difference between reactive and real power from a financial compensation perspective is that reactive power is highly localized. A competitive market for reactive power would have extreme market power concerns to such an extent that marginal cost reactive power pricing would be infeasible. Instead, most regions (including the ISO) provide a resource-specific opportunity cost payment for reactive power that reflects any opportunity costs of not providing real power. Appendix C describes approaches by other ISO/RTOs to address the recovery of fixed costs associated with reactive power capability and the variable costs of providing or absorbing reactive power.[29]

Differences in the market structures and business practices among ISO/RTO regions support different approaches. For instance, a centralized ISO/RTO administered capacity market construct may justify paying resources specific reactive power capability payments because their capacity payments from those markets are specifically linked to real power capability. The eastern RTOs that employ centralized capacity markets procure needed capacity for real power, and pay resources based upon that "MW-only" real power product. Beyond those real power capacity revenues, and any energy market revenues that resources receive, it's possible that some resources in those markets justifiably need additional compensation for fixed costs associated with reactive power equipment that may not be otherwise recovered.

In contrast, the ISO understands that load serving entities in the ISO BAA commonly procure all of the capabilities of a resource under capacity contract that account for resources' overall cost of doing business. This would include the fixed costs of any equipment associated with reactive power capability. The fact that the ISO already requires a standard range of reactive power capability as a general interconnection requirement for traditional synchronous resources, and is proposing to extend that requirement to all new resources at a relatively small cost proportional to a resources total costs is also an important consideration. These new requirements should not place additional burden of potential unrecovered fixed costs upon resources when the uniform requirements are certain and any associated fixed costs can be taken into account during contractual negotiations.

Some stakeholders have contested these facts, arguing that applying a uniform reactive power requirement will create significant capital and operating costs. However, investors and developers will know that they must provide these capabilities and can include those costs as part of their financial assessments of projected costs and revenue streams to inform price terms with buyers when obtaining financeable contractual agreements.

Moreover, as also noted in the technical requirements section, a recent Commission order addressing enhanced inverter requirements in the PJM region acknowledges that the incremental costs for reactive power equipment for asynchronous resources have been greatly

[29] *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7 dated April 22, 2014. http://www.ferc.gov/CalendarFiles/20140414101009-04-11-14-reactive-power.pdf

reduced, and many manufacturers now routinely include reactive capabilities as standard equipment.[30] These changed circumstances corroborate that the ISO proposal to require all new asynchronous resources to provide reactive power capability will not present a barrier to the development of asynchronous resources interconnection to the ISO grid.

Compensation options

In this initiative, the ISO is exploring expanding its mechanisms for financial compensation for the capability and provision of reactive power. The ISO continues to consider enhancing provision payments, which are intended to cover variable costs when resources provide reactive power outside of the standard requirements. The ISO currently compensates resources for the provision of reactive power outside of the standard .95 lead/lag requirements and proposes to continue these provision payments, which are calculated payments based on a resource's opportunity costs when called upon to reduce their real power output to move outside of the standard range.

Financial compensation for reactive power capability under ISO/RTO administered compensation structures may be reasonable in some cases, but this need depends on the regulatory and market constructs of the regions. In the case of the ISO, it continues to be appropriate for resources to be eligible for provision payments. However, the ISO is proposing limited capability payments that are only available to qualified new resources that have demonstrated eligibility by making showings that their contracts do not provide comparable compensation.

Capability payment

As part of this initiative, the ISO has explored developing a reactive power capability payment. A capability payment could be intended to compensate resources for fixed costs for the ability of the resource to operate within the normal leading/lagging standard required under the current tariff. There are two primary methods the ISO considered for determining a potential reactive power capability payment. (1) The FERC-approved AEP method, and (2) a "safe harbor" method. Appendix B reviews both potential methods that were set out in the issue paper in further detail.

The AEP method breaks out the components of a generating unit into components needed for real power and components needed for reactive power.[31] If the ISO were to provide capability payments under this approach it would have to propose enhancements to the AEP methodology for inverter based technologies such as wind and solar photovoltaic resources. This would be a significant effort to develop an additional method for inverter based technologies. A basic framework has been described in in the issue paper and that structure will need significant development. Additionally, if the ISO develops this new AEP method for inverter technology it

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[30] *PJM Interconnection LLC*, 151 FERC ¶ 61,097 (2015) http://www.ferc.gov/CalendarFiles/20150505165917-ER15-1193-000.pdf

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

will face significant Commission scrutiny because it could have broad policy implications for other regions.

The “safe harbor” method develops a consistent payment for all generators based on known cost allocators from prior costs on file with the Commission. One potential issue associated with the “safe harbor” approach is that “safe harbor” payments may lead to the over-recovery or under-recovery of reactive power costs. This would occur as generators with actual reactive power costs lower than the level they would recover using the acceptable allocators would accept the default allocators and over-recover, while generators with actual reactive power costs above the level they would recover using the acceptable allocators, would under-recover. Under-recovering resources may then insist that they file a rate using the AEP methodology, so any costs above their generation-specific safe harbor values could be recovered. Additionally, a “safe harbor” value for asynchronous resources would likely take considerable time to develop and obtain regulatory approvals.[32]

The ISO also notes that capability payments for all resources may be unwarranted when considering the sort of voltage support requirements and the associated capabilities necessary are already part of their responsibility to provide under the Tariff. Section 4.6.5.1 states: Participating Generators shall, in relation to each of their Generating Units, meet all Applicable Reliability Criteria, including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery. Unless otherwise agreed by the CAISO, a Generating Unit must be capable of operating at capacity registered in the CAISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the CAISO from time to time.

Based on stakeholder comments, it appears that providing an across-the-board capability payment for all resources will cause market and contracting inefficiencies. Some stakeholders emphasized that double payment and over-recovery for this capability would result. Additional issues surround the payments flow through to resources themselves. Resources with contracts that didn’t account for a new revenue stream such as this could likely trigger reopener provisions (if included in their contracts) and cause a need to renegotiate the treatment of this new source of revenue based upon the changed revenue outlook to adjust the price terms of their contracts.

The current contracting and procurement practices within the ISO BAA are sufficiently distinct from other organized markets that have previously implemented capability payments. Based on this fact and stakeholders comments that current agreements for most interconnected resources already appropriately cover these reactive power capability fixed costs it may be difficult to justify to the Commission that it is just and reasonable to pay all resources for these capabilities unless these payments are only limited to new resources that are not being comparably compensated.

The ISO proposes to provide capability payments to only new resources that have made a demonstration that their fixed costs for reactive capability equipment are not currently covered under their contracts. Therefore, only resources that are signing a new interconnection

[32] http://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf

agreement (new, repowered, or uprated resources) will be considered eligible to make a showing to receive any capability compensation. The ISO is still considering how these demonstrations would appropriately differentiate new resources that are being compensated under contract and those that have agreements that do not provide appropriate reactive power compensation. It is also important to consider what party would need to ultimately make the decision on these determinations of resource eligibility. The ISO will continue to develop the proposal in this area and welcomes stakeholder feedback.

For these eligible new resources, the ISO needs to continue to develop an appropriate capability payment methodology. The ISO has described some of the issues and challenges with both potential approaches and is seeking additional feedback on developing either of these two methods for those new resources that would be eligible to receive capability payments.

Under current circumstances potential capability payments would be made by the ISO to the each SC for most generation resources. If resources owned by others than the SC are entitled to a capability payment but the SC receives that payment, there may be no provision in current PPAs to pass that payment through to the individual resources. Thus, for the payment to reach the intended generator recipient, current PPAs would need to be amended to provide for the pass-through. Resources eligible for payment could also proactively address this issue including a pass-through provision for these type of revenues for any payments that would otherwise be collected by the SCs. The ISO may need to develop a method to pay those resources directly.

Stakeholders have requested that the ISO provide analysis around the overall costs of these potential capability payments and associated costs of administering the payments. Because the ISO is no longer proposing to provide these payments to all resources the cost impact of the proposal is more uncertain. Due to the reduced scope of these potential capability payments the ISO initially expects the cost impacts to be limited in nature. The ISO will explore ways to estimate how many new resources may seek eligibility for the capability payments.

Reactive power provision payment

The ISO already has rules for the provision of reactive power. The ISO has a mechanism to pay resources for reactive power dispatched outside the standard range required by the tariff. Tariff Section 8.2.3.3 states that if the ISO requires additional Voltage Support, the ISO will instruct the resource to move its MVAR output outside its mandatory range. Section 8.2.3.3 states that for all Generating Units the minimum power factor range will be within a band of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) power factors. Only if the resource must reduce its MW output to comply with such an instruction will it be eligible to recover its opportunity cost under Section 11.10.1.4. Some resources may be required to provide additional support as detailed in individual resource specific agreements as specified below.

Section 11.10.1.4 specifies that the total payments for Voltage Support shall be the sum of the opportunity costs of limiting energy output to enable reactive energy production in response to an ISO instruction. The opportunity cost is calculated based on the product of the energy amount that would have cleared the market at the price of the Resource-Specific Settlement Interval LMP minus the higher of the Energy Bid price or the Default Energy Bid price.

SCs for resources providing reactive power still receive any payments under any long-term contracts even if they also receive an opportunity cost payment. Exceptional Dispatches for incremental or decremental energy needed for Voltage Support are paid and settled under Section 11.5.6.1. RMR Units providing Voltage Support are compensated under the RMR Contract rather than Section 11.10.1.4.

Certain resources that are able to switch between providing real power and reactive power very quickly, also known as "clutch" resources and may be helpful for voltage support in unique situations. Asynchronous resources may also be able to provide reactive power support even during times of low or no output, such as wind or solar resources under cloud cover or at night. These unique characteristics may provide the ISO with needed reactive power support.

The ISO may consider additional provision payment revisions and may consider the creation of a new exceptional dispatch category because these resources would only provide reactive power support if they were not picked up in the market optimization, but were still needed for reactive power. It may be appropriate to compensate these resources for their variable reactive power costs – O&M and energy costs to provide reactive power – through a different mechanism than the current opportunity cost based provision payments.

These resources would not have an opportunity cost because they are "out of the money" in the energy market optimization, but still are providing a service to the ISO. One option may be to provide these resources with an alternative provision payment to incentivize these resources to respond when they would not otherwise have any payment under the current provision compensation structure.

Because these resources have useful abilities to provide reactive power in situations that they would not be rewarded under the current methodology it may be appropriate to enhance their ability to recover variable costs and incentivize their performance. The ISO seeks additional feedback on an appropriate mechanism or revisions to current provision payments for these resources.

Compliance and testing

The ISO currently has the tariff authority to test whether a resource can provide voltage support. Section 8.9.4.1 allows the ISO to test the voltage support capability of a resource by issuing unannounced dispatch instructions requiring the resource to adjust its power factor outside the specified power factor band of 0.90 lag to 0.95 lead, but within the limits of the resource capability curve. Section 8.9.4.2 allows the ISO to test the voltage support capability of other reactive devices, such as shunt capacitors, static VAR compensators, and synchronous condensers) by issuing unannounced dispatch instructions to these devices.

The proposal's universal requirements for all new resources including asynchronous resources will require the proper type and size of reactive power equipment to meet the technical requirements of their interconnection.

Cost allocation

Cost allocation for provision of reactive power outside the standard required range is established under current tariff Section 11.10.1.4. Currently, these cost allocation provisions for Voltage Support assign these costs to load. Each Balancing Authority (BA) that has Measured Demand is allocated and assessed voltage support charges based on the BA's relative share of Measured Demand over the CAISO Control Area. For both short-term voltage support (also referred to as supplemental reactive energy) and long-term voltage support, cost allocation is based upon load ratio share of the system-wide Measured Demand (that includes CAISO metered demand plus deemed-delivered export energy), and excludes any Measured Demand inside a Metered Subsystem (MSS) to the extent that the MSS provides proof of providing its own voltage support.

The ISO believes it is appropriate to keep current cost allocation for provision payments consistent. The ISO is proposing to allocate any compensation payments that are granted to eligible new resources in a manner consistent with the current provision payment cost allocation methodology. This approach is appropriate because it conforms to the ISO's Cost Allocation Guiding Principles. Additionally, the ISO believes that the proposed capability payment mechanism will be limited in scope and the ISO will be justified in allocating these costs similarly to the current provision payments.

6. Next steps

The ISO will discuss this straw proposal with stakeholders during an in-person meeting on August 20, 2015. Stakeholders are asked to submit written comments by September 3, 2015 to InitiativeComments@caiso.com.

Appendix A: Technical requirements background

Generation interconnection process

In the GIP, all synchronous resources must provide their reactive power output information.[33] For asynchronous resources, the ISO uses a case-by-case, system impact study approach to assess whether these resources must provide reactive power supply/absorption capability. The process is further described below. Both synchronous and asynchronous resources that go through the interconnection process may participate in the ISO as *market* resources and must meet the provision standards in the tariff and the generator-specific interconnection agreement.

Assessment of asynchronous resources

The ISO uses a case-by-case, system impact study approach to assess whether asynchronous resources must provide reactive power supply/absorption capability. The ISO conducts this as part of the interconnection process, and it requires an assessment of asynchronous resources within a cluster to determine whether a resource must provide reactive power capability to interconnect to the system based on a range of operating conditions. For asynchronous resources within the cluster study process, the ISO must identify if a resource must provide reactive power capability in order to safely and reliably interconnect the resource.[34] If the ISO identifies such a need, then the resource must have at least a +/- 0.95 power factor range at its POI. If the study results do not demonstrate this need, the ISO does not currently require the resource to provide reactive power capability or impose a requirement to control voltage.

The current study methodology in the ISO generation cluster study was reviewed by stakeholders and subsequently adopted in 2011. A reactive power capability deficiency analysis is performed in each cluster Phase II interconnection study to determine:

- Whether the asynchronous facilities proposed by the interconnection projects in the current cluster must provide 0.95 leading/lagging power factor at the POI.
- Whether network upgrades, including system resources that provide reactive power, are needed to mitigate reactive power deficiency.

First, the ISO conducts the study assuming unity power factor[35] for the asynchronous facilities of the new interconnection projects in the current cluster. Based on two scenarios, a peak and an off-peak, with and without current cluster projects, the ISO develops four base cases for each study group:

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[33] i.e. provide information on the maximum and minimum VAR capabilities.

[34] Asynchronous resources using the ISO's independent study process must provide reactive power capability without the need for the ISO to determine the need for that capability though an interconnection system impact study. *Cal. Indep. Sys. Operator Corp.*149 FERC ¶ 61,100 (2014). http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13674514

[35] Power factor is the ratio between a generator's real power (MW) and apparent power (MVA), where apparent power is the vector sum of the real and reactive power. The power factor range can be leading or lagging. Unity power factor is where the current and voltage are in synch and no reactive power is produced.

- Case 1: Peak pre-cluster base case without the current cluster projects.
- Case 2: Peak post-cluster base case with the current cluster projects modeled at unity power factor.
- Case 3: Off-peak pre-cluster base case without the current cluster projects.
- Case 4: Off-peak post-cluster base case with the current cluster projects modeled at unity power factor.

Second, The ISO performs contingency analysis on all four base cases. The study results determine:

- Whether adding current cluster projects causes normal voltages out of the allowable normal min/max range.
- Whether adding current cluster projects causes post-contingency voltages out of the allowable post-transient min/max range.
- Whether adding current cluster projects causes excessive voltage deviation from the pre-contingency level.
    - Third, the ISO further analyzes critical contingencies that result in excessive voltage deviation using the post-transient power flow. In particular, the ISO might perform an additional analysis to determine the post-transient voltage stability. If significant power transfer occurs, the pre-contingency power transfer can be increased according to applicable voltage performance criteria of the Western Electricity Coordinating Council. The post transient voltage stability analysis will determine:
- Whether the system has sufficient reactive margin according to the planning standards.

If the results indicate reactive power deficiencies, the ISO requires the asynchronous generators in the cluster study group to provide 0.95 leading/lagging power factors at the POI.

Next, the ISO modifies the four base cases above to model the required reactive power capability and conducts the same contingency analysis and post-transient voltage stability analysis again. If the new study results still indicate reactive power deficiencies, the ISO will require transmission system upgrades to mitigate the problem.

Using this approach, the ISO has assessed 187 asynchronous projects (approximately 17,000 MW) through mid-2014 requesting interconnection to the ISO controlled grid and required almost three-fourths of these projects (approximately 12,000 MW) to provide reactive power capability. This means that slightly more than one-fourth of these projects were not required to provide reactive power capability.

Reactive power provision rules

The ISO maintain specific reactive power provision requirements for both synchronous and asynchronous generation in both section 8 of the tariff and in the generation interconnection agreements, which are based on tariff appendices Y – HH. Although slightly different language exists today in the small generation interconnection agreement (SGIA) compared to the large generation interconnection agreement (LGIA) it is the ISO's intent that ultimately, all resources have the same reactive power requirements. **Error! Reference source not found.** summarizes he current reactive power provision rules.

Figure 4: Reactive power provision rules for market resources

	Synchronous generation	***Asynchronous generation***
Power Factor Requirements	Unit must maintain a composite power delivery at continuous rated power output at the terminals of the unit within a power factor range of .95 leading to .9 lagging.	Must operate within a power factor range of 0.95 leading to 0.95 lagging, at the POI, if Phase II interconnection study show requirement is needed.
Power Factor Requirements Provisions	N/A	N/A
Dynamic reactive power capability requirements	Reactive support is automatic and dynamic.	Must be able to provide sufficient dynamic reactive support if study shows need.
Voltage regulation requirements	Unit shall maintain voltage schedule set by ISO or Participating TO by operating within required standards. Whenever an Electric Generating Unit is operated in parallel with the ISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. **This is not in the SGIA.**	If dynamic voltage support is needed, voltage regulators must operate in automatic mode of operation.
Compliance	Unit must pass the reactive support test if unit has requested interconnection in a study area where reactive support needs are not identified as requiring reliability	Interconnection customer must not disable power factor equipment while the unit is in operation.

	network updates in the Study Process. (Appendix DD section 4.2.4)	
Low Voltage Ride-Through Capability	Not needed - synchronous resources automatically have this capability.	Must be able to remain online during voltage disturbances up to certain time periods and voltage levels defined in the interconnection agreements.

Transmission planning process

The TPP study will determine whether additional reactive power capability is needed, accounting for the GIP reactive power capability requirements. If additional reactive power capability is required according to the TPP study, the ISO will identify the most effective and efficient transmission asset to provide reactive power. The provision of and payment for reactive power through the TPP is out of scope in this initiative. Transmission assets cannot participate in the ISO market and are compensated through other mechanisms.

Annual local capacity technical study

The Annual Local Capacity Study finds the minimum capacity needed to meet the Local Capacity Requirement criteria including reactive power needs. If this study identifies a reactive power need, the load serving entities in the local area are informed and allowed to make an informed procurement decision that could mitigate the need. If the LSEs do not procure enough resource adequacy capacity to meet this need, ISO may procure additional resources to meet the need through its back stop authority role. This could be done either through the Capacity Procurement Mechanism (CPM) if both reactive and real power is needed or through a RMR contract if ultimately only reactive power is needed.

Resources procured through the CPM are market resources and have the same participation and provision standards as resources that are required to provide reactive power through the GIP. These resources get an additional capacity payment for their real power capability and must comply with the resource adequacy rules. They are also compensated through the CPM payment for providing reactive power as well as additional market revenues for providing real power.

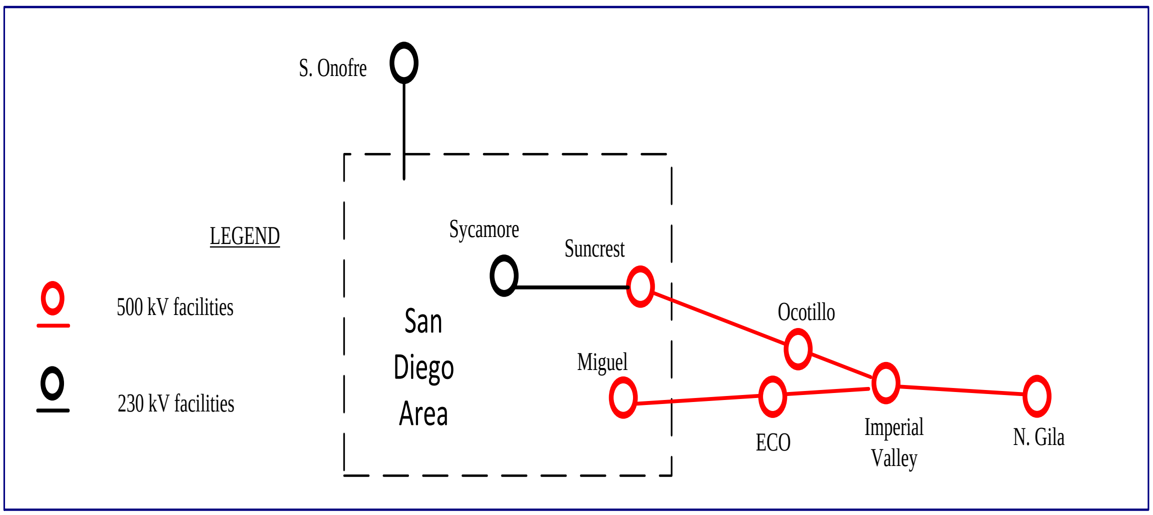
Resources procured through RMR contracts must maintain a voltage schedule in a local area and do not participate in the ISO energy market for real power. Currently the ISO has two synchronous condensers under RMR contracts to maintain grid reliability. All fixed and variable costs, including the energy and O&M costs to provide reactive power are recovered through the RMR contract and not through the market or resource adequacy contract.

Case studies: San Diego/Imperial Valley

A recent ISO interconnection system impact study failed to find the need for a new asynchronous resource interconnecting at the Ocotillo substation in Imperial County, California to provide reactive power capability because the study did not model unexpected operating conditions that actually occurred. Based on the results of the system impact study, the resource could interconnect without an obligation to provide reactive power capability. The resource reached commercial operation in 2013. At the time of the interconnection study, the ISO reasonably assumed that the San Onofre Nuclear Generating Station (SONGS) would operate at least through 2024, its relicensing date. However, as is now known, SONGS unexpectedly retired in June 2013.

Figure 1, shows the approximate locations of the Ocotillo and SONGS facilities. The dotted line reflects the San Diego transmission constrained load pocket.

Figure 5: Simplified Diagram of the transmission serving the San Diego area



In its 2013-2014 transmission planning process, the ISO studied its system with SONGS out-of-service. As part of those studies, the ISO identified a voltage criteria violation at the Suncrest substation following an N-1 contingency of either the Imperial Valley – ECO or ECO – Miguel 500 kV lines. This voltage deficiency triggered the need for a 300 MVAR static VAR compensator at the Suncrest substation. An additional assessment showed that if the asynchronous resource at Ocotillo were providing reactive power through its inverters, the reactive power need at Suncrest would have been reduced by 50 MVAR.

Although the ISO would still have identified a reactive power need in its transmission plan based on the closure of SONGs, that need would have been reduced had the ISO determined that resources at the Ocotillo substation needed to have reactive power capability. While SONGS reflects an extraordinary closure, the fundamental point is that transmission providers cannot foresee each and every retirement or operating scenario on its system. A smaller resource that retires may also create an unexpected reactive power deficiency. For example, a two month outage of a combined cycle plant or the loss of a transmission element may easily create unforeseen voltage issues that require the capability to supply or absorb reactive support.

Another ISO interconnection system impact study failed to find the need for a new asynchronous resource interconnecting at the Imperial Valley substation in Imperial County, California to provide reactive power capability because the study did not model unexpected operating conditions that actually occurred. Imperial Valley substation has both synchronous and asynchronous generation connected to it. The asynchronous generation was not required to provide reactive power. In order to reduce flow on heavily loaded transmission lines the ISO identified the need to bypass series capacitors on two nearby 500 kV lines. The loss of one of these 500 kV lines requires the tripping of generation at Imperial Valley substation. However, it was found that tripping the synchronous generation instead of the asynchronous generation resulted in voltage problems. Therefore, the ISO had to design a generation tripping scheme to only trip the asynchronous generation.

While transmission providers can mitigate this deficiency by authorizing new transmission elements, this process involves an unavoidable time lag and results in the costs applied to all transmission ratepayers rather than generating resources. This may also create inequities between conventional resources and resources that have no reactive power requirement. Adoption of uniform requirements for reactive power capability and voltage control at the time of interconnection helps mitigate potential reactive power deficiencies that may affect the ability of resources to deliver real power.

Over-generation conditions

Failure of asynchronous generators to provide reactive power capability can also have implications during over-generation conditions. Based on an analysis of data for 2014 (see Table 3 below), the ISO had to curtail between 116 MW and 740 MW of resources on certain days due to over-supply. During over-supply conditions, the ISO will solicit SCs to submit decremental bids as mitigating measures, dispatch down flexible resources based on their decremental bids, and utilize exceptional dispatch to reduce production as needed. If remaining asynchronous resources in operation do not have reactive power capability, the ISO system will face a greater risk of voltage issues.

Figure 6: Summary of manual curtailment

Date	Curtailed (MW)	Curtailed (MWh)	Duration of Curtailment (Minutes)	Reason
2/19/2014	116	262	170	Supply/Demand Balance
3/7/2014	123	123	60	Supply/Demand Balance
4/12/2014	427	200	30	Supply/Demand Balance
4/27/2014	740	1,142	90	Supply/Demand Balance

By the end of 2014, wind and solar installed capacity within the ISO's BAA reached approximately 11,457 MW and the ISO expects at least an additional 3,151 MW of large solar PV, 3,564 MW of small solar PV and 1,134 MW of wind resources will interconnect by the end of 2024 (Refer to Table 1). Although the ISO's peak demand is gradually increasing, the minimum demand on the system is not increasing proportionately, and the minimum demand level is not expected to increase much higher than 20,000 MW by 2021 because of technological advancement in energy efficiency and environmental policies to conserve energy.

The data suggests that on some days, especially on weekends and holidays, the ISO's supply portfolio may be comprised largely of asynchronous resources that have displaced synchronous resources. The frequency of these over-supply conditions is expected to further increase with the addition of more distributed solar PV resources because more load would be displaced at the distribution level. If some of these resources do not have reactive power capabilities, the ISO system will face a greater risk of experiencing voltage issues.

Appendix B: Capability payments methodology review

AEP method

The AEP method is a FERC-approved method of breaking out the components of a generating unit into components needed for real power and components needed for reactive power. AEP identified three components of a generation plant for reactive power production:

- Generator and its exciter
- Accessory electric equipment that supports the operation of the generator-exciter
- The remaining total production investment required to provide real power and operate the exciter

The annual revenue requirements of these items are then allocated into real and reactive power buckets. The current approved allocation factor is $MVAr^2/MVA^2$, where MVAr is the megavolt amperes reactive capability and the MVA is the megavolt amperes capability at a power factor of 1.

Generators use actual costs data, either in their FERC Form 1 data or independent data, to justify these costs at FERC. This methodology is used to determine the monthly rate paid to an eligible interconnected generator by calculating its total annual revenue requirement for reactive power as determined by the AEP method and dividing by 12.

The AEP method currently only applies to synchronous generation and would need to be expanded to include asynchronous generation. One possibility would be to use a similar formula for reactive power costs and compare the cost of inverters/capacitors to meet the requirement against the cost to produce at the power factor of 1. Therefore the identified component for asynchronous resources would be:

- Inverter
- Capacitor
- Accessory electric equipment that supports the operation of the inverter or capacitor
- The remaining total production investment required to provide real power and operate the inverters and/or capacitors

The annual revenue requirements of these items could then be allocated similarly to the exiting AEP methodology and go into real and reactive power buckets. It would use the approved synchronous allocation factor of $MVAr^2/MVA^2$, where MVAr is the megavolt amperes reactive capability and the MVA is the megavolt amperes capability at a power factor of 1.

Safe harbor method

A "safe harbor" capability payment method would compensate all generators an equal payment developed based on historical cost data already on file with the Commission. The Commission could use its acquired knowledge of reactive power generator specific costs filed under the AEP method for the past 20 years. They could produce a spreadsheet with known acceptable allocators for specific generation technologies and that could be relied upon to create a "safe harbor" value that generators could recover without filing at FERC.

Appendix C: Summary of ISO/RTO reactive power financial compensation

Entity	Payments	Calculation Method
ISO-NE	Both capability and provision payments. the lost opportunity cost component associated with providing reactive support the cost of energy consumed to provide reactive support; the cost of energy produced to provide reactive support; and the capability cost - fixed capital costs resources incur to install and maintain equipment necessary to provide reactive power.	(1) Lost opportunity cost compensates for lost opportunity in the energy market when a resource otherwise receive an economic dispatch. (2) The cost of energy consumed applies to hydro and pumped storage units, as well as non-generator resources that operate and consume power at the request of ISO-NE or a local control center for the purpose of providing reactive power service. (3) The cost of energy produced applies to reactive resources brought on-line to provide reactive power service. This is included in the total net commitment period compensation (aka uplift) that a resource will receive attributed to the hour(s) during which it provides reactive power. (4) The capability cost component is established each year on a prospective basis, and reflects a base rate prorated among resources based on forecast peak load divided by the sum of all reactive resources' summer seasonal claimed capability, and based on the leading and lagging reactive power available from the resource.
NYISO	Both capability and provision payments. Monthly payments based on annual calculation. Suppliers that qualify to receive payments receive one-twelfth of the annual payment. 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, pro-rated by the number of hours that the generator, synchronous condenser, or qualified non-generator provides voltage support resources.	NYISO calculates the fixed payment as the product of $3919/MVAr and the tested MVAr capacity. NYISO calculates the lost opportunity cost payment as the maximum of zero or the difference between: (1) the MW of the resource'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 resource's energy bid for the reduced output of the generator multiplied by the time duration of reduction in hours or fractions thereof.

Entity	Payments	Calculation Method
	Supplier of voltage support service from a resource dispatched also receives a payment for lost opportunity costs when the ISO directs the resource to reduce its real power output below its economic operating point in order to allow the resource to produce or absorb more reactive power, unless the supplier is already receiving a day-ahead margin assurance payment for that reduction.	
PJM	Both capability and provision payments. PJM determines the amount of reactive supply and voltage control required by transmission providers. 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 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 approved by FERC.	Fixed costs calculated using the *AEP* methodology, and filed with FERC. 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. Separate compensation exists for steam turbine and combined cycle turbines if resource is committed to provide reactive services. Separate compensation exists for synchronous condensers.

Entity	Payments	Calculation Method
MISO	Capability payments. Qualified generators file their annual cost-based revenue requirement and/or cost-based rates for voltage control capability with FERC. MISO provides each qualified resource monthly a pro rata allocation of the amount collected based upon the qualified generator's share of the rate within its pricing zone	Qualified resources seeking compensation for reactive service must file with the Commission to justify its cost-based revenue requirements.
SPP	Provision payments. 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. Qualified generators are paid monthly based on actual usage with no true-ups.	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 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 zonal charges it collects.

See Appendix 3 to FERC Staff Report: *Payment for Reactive Power* in AD14-7 dated April 22, 2014.
http://www.ferc.gov/CalendarFiles/20140414101009-04-11-14-reactive-power.pdf