133 FERC ¶ 61,221
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER10-1791-000

ORDER CONDITIONALLY ACCEPTING TARIFF REVISIONS

(Issued December 16, 2010)

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Paragraph Numbers

1. On July 15, 2010, pursuant to section 205 of the Federal Power Act (FPA),[1] and in accordance with the Commission's October 23, 2009 order,[2] Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and Midwest ISO Transmission Owners[3] (collectively, Filing Parties) filed proposed revisions to the Midwest ISO Open

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[1] 16 U.S.C. § 824d (2006).

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060, at P 68-70 (2009) (October 23, 2009 Order) ("We deny the requests to establish a sunset date for Filing Parties' section 205 Phase I cost allocation methodology because Filing Parties have already committed 'to file the long-term Phase II cost allocation methodology by July 15, 2010. We will, however, condition the acceptance of the instant proposal on Filing Parties fulfilling their commitment to file tariff sheets reflecting the Phase II solution on or before July 15, 2010.'" (footnote omitted)), *reh'g pending*.

[3] For purposes of this filing, Midwest ISO Transmission Owners include Ameren Services Company, as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Co., and Illinois Power Company; American Transmission Company LLC (ATC); Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota); Northern States Power Company (Wisconsin); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company; and Southern Minnesota Municipal Power Agency.

Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)[4] (July 15 Filing). Filing Parties propose to establish a new category of transmission projects designated as Multi Value Projects (MVP) for projects that are determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones.[5] In recognizing the regional orientation of such projects, Filing Parties propose that the costs of the MVPs be allocated to all load in, and exports from, Midwest ISO on a postage-stamp basis. Filing Parties also propose to make permanent the interim cost allocation methodology for generator interconnection upgrades[6] conditionally approved in the Commission's October 23, 2009 Order but propose revisions to narrow the cost burden faced by an initial generator interconnection customer that funds a network upgrade by requiring subsequent interconnection customers that benefit from the same upgrade to contribute to the costs of such upgrade through the creation of a new class of interconnection projects call Shared Network Upgrades (SNU).

2. As the Commission has noted before, cost allocation reform is one of the most difficult issues facing transmission service providers and regional transmission organizations (RTO) and independent system operators (ISO), including Midwest ISO. This is especially true given the changing circumstances affecting the transmission grid, including particularly, the need to upgrade existing transmission infrastructure and build new transmission facilities to satisfy the expanding demands on the transmission system.

[4] Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No.1. When referring to the applicants, this order uses "Filing Parties" and "Midwest ISO" interchangeably unless otherwise noted.

[5] The Commission has shown interest in expanding transmission planning processes and exploring cost allocation issues in its currently pending Notice of Proposed Rulemaking in Docket No. RM10-23-000. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, 75 Fed. Reg. 37884 (June 30, 2010), FERC Stats. & Regs. ¶ 32,660 (2010) (Transmission NOPR). Because the Commission's action today on Filing Parties' MVP proposal precedes any final rule on the Transmission NOPR, we have reviewed the MVP proposal to ensure consistency with existing Commission policies. Midwest ISO, like all jurisdictional entities, will be subject to any future rulemakings.

[6] This methodology assigns to interconnection customers 100 percent of the costs of network upgrades rated below 345 kilovolts (kV) and 90 percent of the network upgrades rated at 345 kV and above, with the remaining 10 percent of the costs being recovered on a system-wide basis.

Efforts to integrate new resources, including significant amounts of location-constrained generation, into existing transmission systems and to address renewable portfolio standards and other regulatory policies challenge existing transmission planning and cost allocation protocols.[7] The expansion of energy markets across the Midwest ISO region, the need to modernize aging infrastructure, and the necessity of maintaining reliable service are also testing existing transmission planning and cost allocation mechanisms.

3. Here, we conditionally accept Filing Parties' proposed Tariff revisions for filing effective July 16, 2010, as further discussed herein. We find that the MVP methodology will identify projects that provide regional benefits and allocate the costs of those projects accordingly. The proposed MVP methodology is an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads. We also find the proposal to maintain the existing cost reimbursement policy for network upgrades, along with the addition of the new classification of projects as SNUs, to be appropriate, as it provides a better balance for allocating cost responsibilities for large network upgrades associated with interconnecting with the electric transmission grid.

4. As explained below, our acceptance is conditioned on Filing Parties submitting a compliance filing that: 1) states in the Tariff that they will review MVPs on a portfolio basis; 2) revises the Tariff to ensure that the MVP usage rate is not applied to export or wheel-through transactions that sink in the PJM region; 3) provides an explanation as to how the proposed Tariff language relating to Monthly Net Actual Energy Withdrawal and Demand Response Resources and Emergency Demand Response resources is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting; and 4) revises the Tariff to clarify that the divisor of the MVP usage charge in Attachment MM reflects the MWhs of grandfathered service provided by each

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[7] *See*, *e.g.,* October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58 ("The Commission has previously recognized that location-constrained resources present unique challenges that other resources do not present. For example, in *CAISO*, the Commission concluded that the barriers to the development of interconnection infrastructure to location-constrained resources highlight the need for flexibility in applying the Commission's interconnection policy to accommodate these resources. The Commission also has acknowledged that stakeholders may seek to plan for transmission projects on a region-wide basis to address region-wide concerns as opposed to planning merely for specific generators or load growth" (footnotes omitted)). *See also Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 2 (2010) (SPP June 17, 2010 Order).

transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements. We also require Filing Parties to submit a compliance filing no later than June 1, 2011 to describe what changes are required to its allocation of Financial Transmission Rights and Auction Revenue Rights in order to reflect the usage-based allocation of MVP costs being accepted here. We further require Midwest ISO to file ongoing annual informational reports[8] with the Commission describing the selection of MVPs, including the achievements and shortcomings of the MVP selection process, after each full planning cycle has been completed.

I. Background

A. Commission-Directed Reform of Transmission Planning Process

5. In Order No. 890,[9] the Commission reformed the *pro forma* open access transmission tariff (OATT) to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a non-discriminatory basis. One of the Commission's primary reforms was designed to address the lack of specificity regarding how customers and other stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in planning activities, the Commission directed all transmission providers to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to their OATT (Attachment K).

6. The nine planning principles each transmission provider was directed by Order No. 890 to address in its Attachment K planning process are: 1) coordination; 2) openness; 3) transparency; 4) information exchange; 5) comparability;[10] 6) dispute

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[8] The Commission does not intend to issue public notices, accept comments, or issue orders on such informational filings.

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

[10] In Order No. 890-A, the Commission clarified that the comparability principle requires each transmission provider to identify, as part of its Attachment K planning process, how it will treat resources on a comparable basis and, therefore, how it will determine comparability for purposes of transmission planning. *See* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

resolution; 7) regional participation; 8) economic planning studies; and 9) cost allocation for new projects. The Commission explained that it adopted a principles-based reform to allow for flexibility in implementation of and to build on transmission planning efforts and processes already underway in many regions of the country. The Commission also explained, however, that although Order No. 890 allows for flexibility, each transmission provider has a clear obligation to address each of the nine principles in its transmission planning process, and all of these principles must be fully addressed in the tariff language filed with the Commission. The Commission emphasized that tariff rules, as supplemented with web-posted business practices when appropriate,[11] must be specific and clear in order to facilitate compliance by transmission providers and place customers on notice of their rights and obligations.

7. As for RTOs and ISOs with Commission-approved transmission planning processes already on file, such as Midwest ISO, the Commission explained that, when it initially approved these processes, they were found to be consistent with or superior to the existing *pro forma* OATT. However, because the *pro forma* OATT was being reformed by Order No. 890, the Commission found that it was necessary for each RTO and ISO either to reform its planning process or show that its planning process is consistent with or superior to the *pro forma* OATT, as modified by Order Nos. 890 and 890-A.[12]

8. On December 7, 2007, Midwest ISO made its filing in Docket No. OA08-53-000 in compliance with Order No. 890's planning requirements. In the May 2008 Planning Order,[13] the Commission accepted that compliance filing, as modified, to be effective December 7, 2007, subject to a further compliance filing. On August 13, 2008, Midwest ISO made its filing in Docket No. OA08-53-001 in compliance with the May 2008

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[11] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1649-55.

[12] *See id.* at P 439; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 174-75. The Commission also reviewed stakeholder processes as part of Order No. 719. *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719 or Final Rule), *order on reh'g*, Order No. 719-A, 74 Fed. Reg. 37776 (Jul. 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[13] *Midwest Indep. Transmission Sys. Operator, Inc.*, 123 FERC ¶ 61,164 (2008) (May 2008 Planning Order).

Planning Order. In the May 2009 Planning Order,[14] the Commission accepted that compliance filing, as modified, subject to a further compliance filing. On July 20, 2009, Midwest ISO submitted its filing in Docket No. OA08-53-002 in compliance with the May 2009 Planning Order. In the March 2010 Planning Order, the Commission accepted that compliance filing, as modified.[15] On April 23, 2010, in Docket No. OA08-53-003, Midwest ISO filed proposed revisions to Attachment FF of the Midwest ISO Tariff to comply with the Commission's directives in the March 2010 Planning Order.[16]

B. Existing Midwest ISO Cost Allocation Methodologies

9. Filing Parties state that the proposed Tariff changes are part of an ongoing, comprehensive review of all of Midwest ISO's Regional Expansion Criteria and Benefits (RECB) transmission cost allocation methodologies that are currently in effect in its Tariff. In the instant filing, Filing Parties propose to establish a new category of projects designated as MVPs and to permanently maintain the interim generator interconnection policy whereby generator interconnection customers throughout most of Midwest ISO will be responsible for 90 or 100 percent of the costs to interconnect to the transmission system, depending on the voltage classification of the interconnection network upgrades. They propose to retain the existing cost allocation methodologies for Baseline Reliability Projects (as approved in the RECB I proceeding[17]) and Regionally Beneficial Projects (renamed Market Efficiency Projects in the instant filing) (as approved in the RECB II proceeding[18]) until such time as their comprehensive review is completed.

10. Under Midwest ISO's currently-effective Tariff, Baseline Reliability Projects are included in the Midwest ISO Transmission Expansion Plan and are needed to maintain reliability, while accommodating the ongoing needs of existing transmission customers.

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[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,169 (2009) (May 2009 Planning Order).

[15] *Midwest Indep. Transmission Sys. Operator, Inc.*, 130 FERC ¶ 61,232 (2010) (March 2010 Planning Order).

[16] Midwest ISO's April 23, 2010 compliance filing is currently pending before the Commission.

[17] *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,106, *order on reh'g*, 117 FERC ¶ 61,241 (2006) (RECB I Order).

[18] *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,209 (RECB II Order), *order on reh'g*, 120 FERC ¶ 61,080 (2007) (RECB II Rehearing Order).

To qualify for cost sharing, such projects must meet a materiality test (i.e., cost at least $5 million or 5 percent of the net plant of the transmission owner). For projects rated at or above 345 kV, 20 percent of the cost of the projects is allocated on a load-ratio share (i.e., postage-stamp) basis throughout Midwest ISO. The remaining project cost is allocated sub-regionally (potentially across several affected pricing zones) based on Line Outage Distribution Factor analyses.[19] For projects rated between 100kV and 344kV, all of the project cost is allocated sub-regionally based on Line Outage Distribution Factor analyses. The Commission approved this method in Midwest ISO's RECB I proceeding.

11. The RECB I proceeding also established cost allocation rules for generator interconnection projects (GIP), which are network upgrades that would not be required "but for" the interconnection of new or increased generating capacity. As accepted by the Commission in 2006, the RECB I proposal required the interconnection customer to pay the entire cost of network upgrades in advance. If, at the time the interconnection customer achieved commercial operation, the interconnection customer demonstrated that the generator was designated as a network resource or committed by a contract of at least one year to supply capacity or energy to a network customer, then 50 percent of the costs of the network upgrades is repaid to the interconnection customer and recovered from transmission customers through the same cost allocation rule that applies to Baseline Reliability Projects. Otherwise, the interconnection customer is directly assigned 100 percent of the costs. Exceptions to this policy have been granted to International Transmission Company and Michigan Electric Transmission Company LLC and ATC.[20]

12. Under Midwest ISO's currently-effective Tariff, Regionally Beneficial Projects are economic upgrades that meet specific standards. To qualify for cost sharing, the project must first satisfy two benefits tests as well as a materiality test. The benefits tests are: 1) the present value of the sum of the production cost benefit and the Locational Marginal Pricing (LMP)-based energy cost benefit must be greater than zero; and 2) the proposed project must satisfy a variable project Benefit/Costs Ratio threshold (where Benefit = 0.7*production cost benefit + 0.3*LMP benefit). This threshold varies linearly from 1.2 (for projects with an in-service date within 1 year) to 3.0 (for projects with an in-service date 10 or more years out). The materiality test requires that the project: 1)

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[19] The Line Outage Distribution Factor method considers the flow effects of a given facility's outage on transmission facilities in each pricing zone, also taking into account the length of each affected transmission facility.

[20] *International Transmission Company, et al.*, 120 FERC ¶ 61,220 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *American Transmission Company, LLC, et al.*, 120 FERC ¶ 61,221 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *ITC Midwest LLC*, 124 FERC ¶ 61,150 (2008) (August 7, 2008 Order).

cost more than $5 million; 2) involve facilities with voltages of 345 kV or more (high-voltage); and 3) not be designated as either a Baseline Reliability Project or a Transmission Access Project.

13. If the project meets the benefits and materiality tests, then 20 percent of the project cost is allocated on a load share basis throughout Midwest ISO. The remaining 80 percent of the cost is allocated to three sub-regions based on a Weighted Gain-No Loss beneficiary analysis where the Weighted Gain-No Loss metric for each planning sub-region is the weighted sum of 70 percent of the production cost benefit and 30 percent of the LMP energy cost benefit metric over the entire modeling period. However, if a sub-region does not benefit from the project (i.e., the weighted sum of the production cost benefit and the LMP energy cost benefit is negative), such sub-region will not see a share of the 80 percent of project cost.

14. On March 15, 2007, the Commission conditionally accepted the RECB II proposal.[21] On rehearing, the Commission further directed Midwest ISO to make informational reports in August 2008 and August 2009 that analyze the effectiveness of all of the transmission expansion cost allocation methodologies.[22]

15. In its August 2008 report, Midwest ISO advised the Commission that many stakeholders were dissatisfied with the RECB cost allocation rules and recommended a continued review of the unanticipated consequences of those rules, and consideration of possible solutions, through the RECB Task Force. Midwest ISO indicated that such discussions would be guided by the Commission's policy under Order No. 890 favoring cost allocation rules generally supported by state authorities and participants across the region.

16. On July 9, 2009, in Docket No. ER09-1431-000, Midwest ISO and certain Midwest ISO transmission owners (July 9 Applicants) filed an interim cost allocation proposal (Interim Cost Allocation Proposal) to address certain unanticipated consequences experienced under the then-effective RECB cost allocation rules for GIPs. As described by July 9 Applicants, zones with high wind-power development potential and low native load were burdened with a disproportionate share of the costs of GIPs. July 9 Applicants proposed to: 1) eliminate the Line Outage Distribution Factor analysis-based allocation of GIPs to load in pricing zones; 2) assign, to interconnection customers, the share of costs previously allocated to loads based on the Line Outage Distribution

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[21] RECB II Order, 118 FERC ¶ 61,209, RECB II Rehearing Order, 120 FERC ¶ 61,080.

[22] RECB II Rehearing Order, 120 FERC ¶ 61,080 at P 9.

Factor analysis; and 3) eliminate the requirement that an interconnection customer demonstrate that it has been designated as a Midwest ISO network resource or that it has executed a power purchase agreement for a period of at least one year with a network customer to be eligible for cost sharing. Under the Interim Cost Allocation Proposal, interconnection customers would be responsible for 100 percent of the costs of GIPs rated below 345 kV and 90 percent of the costs of GIPs rated at 345 kV and above (with the remaining 10 percent being recovered on a system-wide basis). Midwest ISO also offered to provide the Commission with quarterly reports on the status of its Phase II stakeholder discussions.

17. In the October 23, 2009 Order, the Commission accepted the Interim Cost Allocation Proposal conditioned upon the July 9 Applicants meeting their commitment to file superseding Tariff revisions on or before July 15, 2010, and required informational status reports to be submitted on November 20, 2009, February 26, 2010, and May 28, 2010. The Commission also recognized that Midwest ISO was engaged in a stakeholder process that was looking at a longer-term solution to the existing cost allocation issues. The Commission strongly encouraged Midwest ISO and its stakeholders to dedicate themselves to use the stakeholder process for the evaluation of Phase II reforms to transmission planning and cost allocation to more efficiently plan transmission expansions to interconnect and integrate new generation resources. The Commission suggested that "stakeholders may take a comprehensive approach to evaluating transmission needs by considering what upgrades are needed in light of load growth forecasts, aggregate generation interconnection requests, reliability and economic needs and benefits, and state resource policies."[23]

C. Stakeholder Process

18. Filing Parties state that the instant filing is the result of months of Midwest ISO stakeholder and RECB Task Force discussions in close coordination with the Organization of MISO States (OMS) through its focused Cost Allocation and Regional Planning (CARP) working group for the purpose of addressing the Commission's directive in the October 23, 2009 Order. The work of these stakeholder groups and the involvement of the Midwest ISO transmission owners is detailed in the informational reports filed by Midwest ISO pursuant to the October 23, 2009 Order.

19. Formed in January 2009, CARP is comprised of one Commissioner (or their proxy) from each of the Midwest ISO member states. Each state gets one vote on each matter brought before the group. CARP requests that Midwest ISO staff perform analyses and run scenarios in order to provide useful information for CARP to then

[23] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 60.

evaluate and vote on. Commissioner Lauren Azar of Public Service Commission of Wisconsin is the Chair of CARP. The meetings are open to the public, but active participation is limited to the OMS representatives.

20. The RECB Task Force Phase II began on June 24, 2009. The purpose of the RECB Task Force Phase II was to develop Tariff language focused on a permanent cost allocation methodology to evaluate and/or amend the interim cost allocation methodology. Commissioner Lauren Azar also served as the Chair of this group. The primary difference between the RECB Task Force Phase II and CARP was the open involvement of interested stakeholders. Whereas CARP participation was limited to OMS representatives, the RECB Task Force Phase II was an open, Midwest ISO-wide stakeholder forum.

21. During the same period, Midwest ISO developed potential solutions using its analysis along with input from CARP and the RECB Task Force Phase II. Eventually, three solutions to the generator interconnection problem were proposed. Those proposed solutions were developed by: 1) Midwest ISO; 2) certain Midwest ISO transmission owners; and 3) CARP.

22. During the stakeholder process, Midwest ISO originally proposed a hybrid between injection-withdrawal and highway-byway methodologies.[24] The injection component would be used for local costs and be calculated based on existing pricing zones or a combination of pricing zones and on a 12-month coincident peak or nameplate capacity (demand-based) methodology. A transmission usage study within each zone would produce the actual percentages assigned to either injections or withdrawals. For example, in zones with significantly more generation than load, the generators would have a larger percentage of the "local" revenue requirement. Regional costs would be allocated 100-percent region-wide to load using a usage or megawatt-hour (MWh) charge. Midwest ISO stated that that proposal would address the issues raised by the

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[24] Midwest ISO November 20, 2009 Informational Report, Docket No. ER09-1431-000.

LECG Report[25] on the original pure injection/withdrawal methodology initially considered by CARP.[26]

23. Certain Midwest ISO transmission owners presented an alternative that included transmission system overlay projects called unique purpose projects. Unique purpose projects would be identified during Midwest ISO's MTEP Planning Process with stakeholder input to the combined top-down and bottom-up analysis and would be approved for construction by the Midwest ISO Board of Directors (Midwest ISO Board). Unique purpose projects would enable public policy goals, be indentified through the Midwest ISO planning process, and be vetted through the stakeholders. This proposal assigned 100 percent of the costs of unique purpose projects to load on a postage-stamp basis and 100 percent of the costs of generation interconnection upgrades to generators.[27]

24. An OMS CARP proposal was similar to the Midwest ISO transmission owner proposal described above. However, 20 percent of the costs were allocated to generators on a region-wide basis.[28]

25. After considering the different proposed solutions, Filing Parties developed their instant proposal. The instant proposal uses inputs from CARP, the RECB Task Force Phase III and Midwest ISO Transmission Owners. Midwest ISO further designed the

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[25] Scott Harvey and Susan Pope, LECG, LLC, *Evaluation of MVP Transmission Cost Allocation Design* (June 9, 2010), *available at* http://www.midwestiso.org/publish/Document/15cf2f_128d94d853e_-7db40a48324a/Item%2003a%20-%20EvaIuation%20of%20MVP%20Transmission%20CA%20Design.pdf?action=download&_property=Attachment (LECG Report).

[26] The LECG Report on the effects of injection-withdrawal highlighted a few potential problems with the market. Mr. Scott Harvey stated that usage charges on energy storage resources (e.g., Ludington Pumped Storage) will tend to overcharge such a unit and could hamper further involvement in the market. This could be a barrier to future entries and could also have a negative effect on wind involvement. Mr. Harvey also claimed that usage charges (MWh charges instead of megawatt (MW) charges) that vary by sub-region should be avoided, as they could have a negative effect on competition. The LECG Report also found that the proposed methodology could produce some significant unpredictability regarding future grid upgrades.

[27] Midwest ISO May 28, 2010 Informational Report, Docket No. ER09-1431-000.

[28] *Id.*

unique purpose project definition to become the instant MVP proposal. Midwest ISO also determined not to assign the costs of MVPs to generators, while also making permanent the interim cost allocation methodology for GIPs.[29]

II. The Instant Filing

26. Filing Parties state that Midwest ISO and its stakeholders have fully considered the October 23, 2009 Order's directives in developing the MVP and generator interconnection network upgrade proposals. They state that the instant proposal recognizes evolving industry and public policy conditions requiring the development of a new paradigm to facilitate the development of new transmission facilities, including the accommodation of renewable energy and other generating facilities that may be location-constrained, as well as the construction of new transmission facilities to address reliability needs and economic benefits on a regional basis. Moreover, the proposed revisions to the Tariff recognize that, to facilitate construction of such facilities, a new cost allocation mechanism is necessary to fairly allocate costs to beneficiaries across the entire Midwest ISO region. Filing Parties state that the proposal: 1) is consistent with Commission policy that costs are fairly assigned among participants; 2) provides adequate incentives to construct new transmission; and 3) is supported by state authorities and participants across the region. They further assert that this filing has been made in full consideration of the October 23, 2009 Order's directives, as well as the recently issued Transmission NOPR.[30] Filing Parties propose to: 1) establish a new transmission project category designated as MVPs, and a corresponding cost allocation methodology; 2) create SNUs, network upgrades that are funded by interconnection customer(s) and also benefit other interconnection customers that are identified as beneficiaries within five years to share the costs of network upgrades on which they mutually rely; and 3) otherwise retain the existing cost allocation for network upgrades needed for generator interconnection projects.[31] Filing Parties state that these revisions represent broad stakeholder consensus, equitably balance the interests of all parties, and will offer the greatest overall benefits for Midwest ISO and its customers.[32]

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[29] Filing Parties July 15, 2010 Filing, Transmittal Letter at 7-11.

[30] *Id.*, Transmittal Letter at 12-15 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660).

[31] *Id.*, Transmittal Letter at 1-2.

[32] *Id.*, Transmittal Letter at 11.

27. Filing Parties note that, under the principle of cost causation, the Commission must ensure that the costs allocated to a beneficiary are at least roughly commensurate with the benefits that are expected to accrue to that entity, but cost allocation is not an exact science where costs and benefits are allocated with exact precision.[33]

28. According to Filing Parties, MVPs will provide regional benefits, primarily through reductions in transmission losses, regional congestion costs, and the region's installed capacity requirement. MVP costs will be recovered through a system usage (i.e., MWh) charge allocated to all load in, and exports from, Midwest ISO.[34] The charge, called the MVP usage rate, will be used to recover the MVP annual revenue requirement from monthly withdrawals, exports, and wheel-through transactions, as described and calculated in proposed Attachment MM of the Tariff. The proposed MVP cost allocation "does not make an upfront allocation of costs based on an analysis of benefits and usage at a specific point in time, but instead allocates costs based on usage over time."[35] Thus, Filing Parties also state that regional cost-sharing for these projects avoids the disproportionate impacts to native load in prime wind-power development areas and improves the region's ability to attract new generation that fulfills public policy goals.[36]

29. Filing Parties propose that, in order to qualify as an MVP, a project must meet at least one of the following criteria:

- Criterion 1 – [An MVP] must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably

[33] *Id.*, Transmittal Letter at 12-13 (citing, *e.g.*, *Illinois Commerce Commission v. FERC,* 576 F.3d 470, 476-477 (7th Cir. 2009) (*Illinois Commerce Commission*)). In *Illinois Commerce Commission*, the United States Court of Appeals for the Seventh Circuit (Seventh Circuit) granted an appeal challenging the cost allocation for new transmission facilities in PJM. In the challenged order, the Commission determined that the existing rates were unreasonable and should be replaced with a rate that spreads the costs of new facilities at 500 kV and above to the entire PJM region. The court held that a system-wide allocation of future 500 kV and above transmission costs was not supported by substantial evidence.

[34] Filing Parties July 15, 2010 Filing, Transmittal Letter at 2.

[35] *Id.*, Transmittal Letter at 25. Here Midwest ISO contrasts its proposed usage charge with a demand charge.

[36] *Id.*, Transmittal Letter at 3.

and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.[37]

- Criterion 2 – [An MVP] must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost [R]atio of 1.0 or higher where the Total MVP Benefit-to-Cost [R]atio is described in Section II.C.6 of [] Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.[38]

- Criterion 3 – [An MVP] must address at least one Transmission Issue associated with a projected violation of a [North American Electric Reliability Corporation (NERC)] or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.[39]

30. Reflecting the regional nature of the projects, Filing Parties state that projects considered for MVP cost allocation must be included in the transmission planning process. They cannot be network upgrades constructed only because of an interconnection or transmission service request.[40] Further, a proposed transmission project should not contain any transmission facilities listed in Attachment FF-1 of the Tariff,[41] and the total cost of the transmission project must be greater than or equal to the

[37] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451A.

[38] *Id.*

[39] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451B.

[40] *Id.*, Transmittal Letter at 22.

[41] Attachment FF-1 includes a list of projects that were excluded from cost sharing during the RECB I proceeding.

lesser of $20 million or 5 percent of the constructing transmission owner's contemporaneously reported net transmission plant. Facilities associated with projects considered for MVP cost allocation must not be in service, under construction, or approved for construction by the Midwest ISO Board prior to July 16, 2010, or the date the constructing entity becomes a Midwest ISO transmission owner, whichever is later. In addition, projects cannot be considered for MVP cost allocation if they include: 1) an underground or underwater transmission line with costs above and beyond the cost of an alternative overhead transmission line providing comparable benefits; or 2) any direct current transmission line, and associated terminal equipment, that is not under the direct functional control of Midwest ISO.[42]

31. Filing Parties state that projects considered for MVP cost allocation must include some facilities operating at or above 100 kV, but the project can also include facilities operating below 100 kV. Lower-voltage facilities will be considered if they are required as part of the MVP. Filing Parties provide the following example: "…if an MVP starts out as the construction of a 765 kV transmission line, and installation of that transmission line results in an overload on a nearby 69 kV transmission line that would not have otherwise occurred, the costs to upgrade the 69 kV line can be included in the MVP cost allocation."[43] Thus, while a proposed MVP may only include facilities operating at or above 100 kV, if those facilities will impact facilities operating at or below 100 kV, the costs of mitigating those impacts will be included in the MVP cost allocation.

32. Filing Parties also claim that the MVP cost allocation would not distort the markets, as opposed to the distortions that might result from imposing a charge on generators and import transactions. Although there could be market distortions from the proposed export charge, Filing Parties believe that charging exports is necessary to: 1) avoid providing an undue advantage to external loads that use Midwest ISO's transmission system; and 2) place market participants serving external loads in a comparable position to Midwest ISO loads. Filing Parties acknowledge that Midwest ISO may need to modify the Financial Transmission Right and Auction Revenue Right allocation processes so that the benefits of MVP transmission are similarly socialized.[44]

33. Filing Parties submitted a list of 16 potential starter projects as an illustration of the types of projects that would qualify as MVPs. These starter projects were identified

[42] Filing Parties July 15, 2010 Filing, Transmittal Letter at 22-23.

[43] *Id.*, Curran Test. at 31. These sub-100kV facilities are referred to as "underbuild" facilities.

[44] Filing Parties July 15, 2010 Filing, Transmittal Letter at 27-28.

through a number of processes: 1) the Regional Generation Outlet Study, a transmission expansion plan developed to facilitate the Renewable Portfolio Standard objectives that eleven out of thirteen Midwest ISO member states have passed or adopted; 2) the "Top Congested Flowgate" and "Cross-Border Top Congested Flowgate" studies; 3) the Narrowly Constrained Area Targeted Study, a transmission expansion planning study intended to identify and mitigate areas of persistent congestion; 4) the Definitive Planning Phase and System Planning and Analysis studies performed during Midwest ISO's generator interconnection process; and 5) an economic and reliability analysis of MTEP Appendix B and C projects developed and studied as part of the traditional Midwest ISO transmission expansion planning process to address future reliability needs.[45] The list of potential MVPs includes transmission lines in every region of the Midwest ISO footprint and represents about $4.6 billion in investment to be developed over the next 10 years. Of the potential MVPs, one is 230 kV, one is 765 kV, and fourteen are 345 kV.

34. Filing Parties performed an analysis of the MVP starter projects and estimate that these projects will deliver between $582 million and $798 million in <u>annual</u> economic benefits starting in 2015 from expected production cost savings, reductions in transmission losses, and a reduction in the region's reserve margins.[46] Filing Parties divide these estimated annual savings into the following categories:

- Between $297 million and $423 million in annual adjusted production cost savings, spread almost evenly across all Midwest ISO Planning Regions;

- Between $68 million and $104 million in annual transmission system loss savings when the starter projects are put into service;[47] and

- Between $217 million and $271 million in annual reductions of the region's reserve margin is realized due to load diversity.[48]

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[45] Projects in MTEP Appendix C are proposed upgrades for which a need has not been established but which may be beneficial. Once an upgrade has been identified as a potential solution to a reliability problem or potentially economically beneficial project, it is moved into MTEP Appendix B. All proposed projects start in MTEP Appendix C.

[46] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[47] This estimate is associated with an annual reduction in transmission losses of approximately 1,500,000 to 2,000,000 MWh. *Id.*, Curran Test. at 24.

[48] *Id.*, Curran Test. at 26.

35. Filing Parties note that higher production cost savings and savings in deferred capacity investment could add billions of dollars to this indicative estimate of the MVP starter projects in the long run.[49] For example, Filing Parties estimate that the annual production cost savings, listed in the first bullet above, increases to between $400 million to $1.3 billion by 2025.

36. Filing Parties state that related benefits quantified from the MVP starter projects include annual potential load cost savings ranging from $14 million to $984 million in 2015 and negative $19 million to $2 billion in 2025.[50]

37. Filing Parties indicate that further benefits may be realized, although these further benefits were not quantified from the MVP starter projects. They state that even a relatively small reduction of 0.5 percent in reserve requirements would result in a deferral of about 500 MW of capacity investment, saving approximately $500 million.[51] Filing Parties also indicate that a transmission system that is more resilient to contingencies, and thus more reliable, should reduce wind facility curtailments by approximately 25 percent in the east region.[52] Moreover, Curran states that those benefits do not include real, but harder to quantify, benefits of satisfying regional public policy objectives and ensuring regional reliability.[53]

38. By contrast, Curran states that the estimated annual revenue requirement for the starter projects is $675 million.[54]

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[49] *Id.*

[50] *Id.*, Lawhorn Test. at 13-14. Lawhorn explains that load cost is the cost that load serving entities pay to purchase energy to serve their load served; it is the MW of load multiplied by the load-weighted LMP. Lawhorn states that a negative load cost savings is the result of neighboring pools having access to less expensive generation that was previously unavailable due to transmission constraints. As outside pools access less expensive generation, their load costs decrease; however, the load costs for the source pool increase.

[51] *Id.*, Curran Test. at 25.

[52] *Id.*, Transmittal Letter at 16-17, Lawhorn Test. at 12-14.

[53] *Id.*, Curran Test. at 26-27.

[54] *Id.*

39. In addition to estimating the savings that the potential starter projects would provide (mentioned above), Midwest ISO studied the regional usage of certain facilities including those studied in the Regional Generation Outlet Study. Midwest ISO defined local usage as delivering energy from local facilities to local load, and any other usage as regional.[55] It used a sample of 2.5 percent of hours distributed throughout the year (i.e., 219 hours) to approximate the annual load duration curve. Further studies were completed on various classes of transmission facilities proposed in the long term transmission plan, including over two hundred 345 kV and 765 kV facilities. Midwest ISO describes these as "the best available representation of the type of future transmission facilities that would likely be categorized as MVPs."[56] The mileage-weighted analysis showed that at least 80 percent of the usage of these facilities would be regional.[57]

40. In addition to proposing the MVP category, Filing Parties propose to create SNUs. If a project is designated as an SNU, the interconnection customer that originally funded such project that is found to benefit other interconnection customers that come later would be eligible for contributions from the late-coming interconnection customers. To be considered for SNU cost sharing, a project must: 1) be identified in a generator interconnection agreement that is effective after July 15, 2010; 2) have an actual in-service date that is less than five years from the date of the publication of a system impact study that identifies the upgrade as being eligible for contribution; and 3) have been determined by Midwest ISO to benefit a later-interconnected interconnection customer.[58]

41. Filing Parties claim that, with the introduction of the MVP and SNU classifications, the current burden on interconnection customers of paying for network upgrades will be significantly reduced. Filing Parties acknowledge that those network upgrade projects that are required solely for generator interconnection will continue to be subject to the existing cost allocation methodology. According to Filing Parties, "[i]nterconnection [c]ustomers that choose to site their projects in areas of the system that require transmission reinforcement, but are consciously outside [of] the areas where

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[55] *Id.*, Curran Test. at 28. Midwest ISO provided no further explanation of the term regional, though Criterion 2 does specify that economic benefits must accrue to multiple pricing zones. *Id.*, Transmittal Letter at 21.

[56] *Id.*, Curran Test. at 28. Of the fifteen proposed starter projects, one is 230 kV, one is 765 kV, and 13 are 345 kV.

[57] *Id.*, Curran Test. at 27-28.

[58] *Id.*, Transmittal Letter at 31-32.

generator access will be improved by MVPs, will cause and properly should bear nearly all [of] the costs of Network Upgrades needed in these areas to enable their reliable interconnection to the system . . ."[59]

42. As Filing Parties explain, the SNU designation is meant to solve the "first mover" problem that results from the "lumpiness" of transmission upgrades. This problem occurs when an Interconnection Customer (Generator A) is required to fund a network upgrade, and then interconnection customers (Generators B and C) come soon and benefit from the network upgrade funded by Generator A. Transmission facilities are not custom built, so an upgrade generally provides more capacity than is immediately needed (in this case, enough for Generators A, B, and C).[60] The SNU designation builds on the Common Use Upgrade already in place in the Tariff. The Common Use Upgrade allows several known beneficiaries of a network upgrade to share the costs of these upgrades in advance. The SNU expands this to assign costs to beneficiaries who were not known at the time of the upgrade.[61]

43. Filing Parties request waiver of the prior notice requirement to permit the proposed Tariff revisions to become effective on July 16, 2010. Filing Parties request that the Commission act on the filing during or prior to the Commission's December 16, 2010 meeting.

III. Notice of Filing and Responsive Pleadings

44. Notice of Filing Parties' filing was published in the *Federal Register*, 75 Fed. Reg. 43,961 (2010), with interventions and protests due on or before September 10, 2010.[62] Notices of intervention and motions to intervene were filed by the entities listed in the appendix to this order. The entities that filed protests and comments, and answers, are also listed in the appendix. The party abbreviations listed in the appendix will be used throughout this order.

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[59] *Id.*, Transmittal Letter at 4.

[60] *Id.*, Laverty Test. at 5-8.

[61] *Id.*, Transmittal Letter at 38.

[62] *See* Errata Notice issued on July 20, 2010 in this docket.

IV. Procedural Matters

45. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the notices of intervention and the timely, unopposed motions to intervene serve to make the entities who filed them parties to this proceeding.

46. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2010), the Commission will grant all of the late-filed motions to intervene given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

47. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers because they have provided information that assisted us in our decision-making process.

V. Substantive Matters

48. In this order, the Commission finds that the proposed MVP process is just and reasonable and accepts it for filing subject to modifications. We expect the functional approach to MVP selection, as reflected in the MVP criteria, to allow Midwest ISO and its members to achieve a number of goals at one time: 1) to identify transmission projects that will benefit the grid and that may also satisfy documented energy policy mandates or laws; 2) to ensure thorough, transparent consideration of the many factors that will determine which transmission projects should receive regional cost allocation; 3) to allow Midwest ISO flexibility to move forward MVPs to maximize benefits within and across the region; and 4) to further progress toward the goal of facilitating efficient regional transmission planning.

49. However, as part of our acceptance, we will require Filing Parties to make two compliance filings and to submit ongoing annual information reports. In the first compliance filing, due within 60 days of this order, we direct Filing Parties to: 1) state in the Tariff that they will review MVPs on a portfolio basis; 2) revise the Tariff to ensure that the MVP usage rate is not applied to export or wheel-through transactions that sink in the PJM region; 3) provide an explanation as to how the proposed Tariff language relating to Monthly Net Actual Energy Withdrawal and Demand Response Resources and Emergency Demand Response resources is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting; and 4) clarify that the divisor of the MVP usage charge in Attachment MM reflects the MWhs of grandfathered service provided by each transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements. In the second compliance filing, due on or before June 1, 2011, we direct Filing Parties to describe what changes to Midwest ISO's allocation of congestion rights are necessary to reflect the allocation of MVP costs. We further require Midwest ISO to file ongoing annual informational reports

with the Commission describing the selection of MVPs, including the achievements and shortcomings of the MVP selection process, after each full planning cycle has been completed.

50. In addition, we will accept Filing Parties' proposal to make permanent the generator interconnection cost allocation methodology that the Commission conditionally accepted on an interim basis in its October 23, 2009 Order. In accepting this provision, the Commission understands that generator interconnection customers will be required to shoulder 90 percent or 100 percent of the network upgrade costs associated with their interconnection requests; however, the Commission expects that the magnitude of these costs can be significantly mitigated as MVPs are approved and added to Appendix A of the MTEP.

51. Finally, we will accept Filing Parties proposal to allow late-coming interconnection customers who benefit from network upgrades built by an earlier interconnection customer to pay a portion of the costs of the upgrades that qualify as SNUs. By accepting this provision, the Commission expects that the financial burden on first-mover interconnection customers will be further reduced.

A. Demonstration of Benefits Being Commensurate with Costs

52. Under Filing Parties' proposal, projects will be eligible for MVP cost allocation if they meet one of the three criteria discussed above, are selected through the MTEP planning process, and meet the minimum cost and voltage levels specified above. The MTEP process will be open and transparent and allow for stakeholder participation. MVPs will be assembled into a portfolio in the MTEP process to be analyzed for MVP cost allocation, with a goal of providing a regional solution that globally benefits all users of the Midwest ISO transmission system.

53. MVP costs will be allocated system-wide to Midwest ISO load, exports, and wheel-through transactions based on actual energy usage. To support Filing Parties' proposal, Midwest ISO performed a series of economic analyses based on a set of 16 potential MVP starter projects. These studies project benefits in 2015 of $582 million to $798 million.[63] In addition, Midwest ISO performed a transmission usage study on over two hundred 345 kV and 765 kV facilities identified through the Regional Generation Outlet Study. This analysis showed that system usage of these facilities would be 80-percent regional.[64]

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[63] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[64] *Id.*, Curran Test. at 28.

54. In this order, we accept Filing Parties' proposal for filing, and grant waiver of the 60-day notice period to make it effective on July 16, 2010. We find that Filing Parties have demonstrated that their proposed package of processes, which together will lead to the approval of MVPs for regional cost sharing, and will appropriately match the regionally-allocated costs of MVPs to the benefits of those projects. Specifically, we find that the three criteria will determine that each individual project will have regional benefits, and that the portfolio approach to project selection ensures that those benefits will be widely spread around the Midwest ISO region. We will require Midwest ISO to make a compliance filing that includes the portfolio approach to project selection in its tariff, and we will also require a series of informational reports that will allow us to monitor, going forward, the function and effectiveness of the MVP process.

55. We disagree with arguments that we should change the three major criteria, the voltage requirements, or the minimum $20 million cost threshold for including a project as an MVP. We find that the Filing Parties' proposal will work alongside, rather than subsume, existing cost allocation and generator interconnection processes. Filing Parties have justified their proposal to continue the existing cost allocation for generator interconnection-related network upgrades, and we approve their proposal to maintain a 10 percent reimbursement to the generator for the costs of such projects. We also find that Filing Parties' proposal to share the costs of Shared Network Upgrades among first-moving and later-coming generators is just and reasonable.

56. Finally, we approve the MVP Usage Rate as a just and reasonable means of recovering the costs of MVPs. Due to existing contractual obligations, including seams elimination between Midwest ISO and PJM, we decline to apply this rate to exports to PJM, or to grandfathered agreements within Midwest ISO.

1. Comments

a. General

57. Acciona, Alliant, ATC, AWEA-WOW, Edison Mission, E.ON, Fresh Energy, Gamesa, Iberdrola, Indiana OUCC, Michigan Commission, MidAmerican, Midwest TDUs, Minnesota Commission-Minnesota Security, NextEra, NIPSCO, SummitWind, and Wisconsin Electric all comment in general support of the filing, while expressing limited concern over specific aspects of the proposal. Acciona states that MVPs providing long-term, region-wide benefits fit the description in the recent Commission Transmission NOPR of projects worthy of region-wide cost allocation.[65]

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[65] Acciona Comments at 5-6 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 156).

58. ATC states that, while transmission lines built to support efficient renewable energy mandates will be regionally beneficial, Midwest ISO currently does not have a cost-sharing mechanism in its Tariff that adequately reflects the regional value of these transmission facilities. Because of this, ATC recommends that the Commission approve the MVP proposal, stating that the cost of constructing transmission projects that provide regional benefits and that assist in fulfilling specific public policy mandates should be shared regionally to reflect the value of the benefit achieved.[66]

59. Iberdrola also states that the instant proposal would specifically identify those facilities that enable location-constrained renewable resources (typically in western Midwest ISO) to provide energy to meet state renewable portfolio standard requirements. Eleven of thirteen Midwest ISO states have already adopted renewable portfolio standards or clear renewable energy goals for their incumbent utilities, and the Midwest ISO Regional Generation Outlet Study developed a transmission expansion plan to facilitate achievement of the state renewable portfolio standard objectives.[67] Thus, Iberdrola states, the MVP proposal will provide broad, regional benefits throughout Midwest ISO's footprint. Iberdrola also argues that Midwest ISO provided sufficient analysis to support that claim. Further, Iberdrola states that the Commission considers whether a cost allocation proposal provides adequate incentives to construct new transmission; Iberdrola believes that the MVP proposal will in fact facilitate the construction of transmission facilities.

60. Several parties request modification to one or more of the criteria that would determine which projects qualify as MVPs. Where protestors request specific revisions to the criteria, they are listed below. Certain protestors object to the MVP criteria in general or to the cost allocation proposal. MISO Northeast Transmission Customers argue that nothing in Midwest ISO's proposal will limit the amount of transmission built to what is actually needed, as opposed to what western states in Midwest ISO may desire. MISO Northeast Transmission Customers state that the proposed criteria do not compel any investigation of possible less-costly alternatives to proposed MVPs.[68] Joint Protestors request that the Commission require Midwest ISO to develop a narrower, more defined stakeholder methodology for assessing the regional costs and benefits (i.e., SPP's Highway/Byway methodology).[69] Indiana Commission and MPPA argue that the

[66] ATC Comments at 4.

[67] Iberdrola Comments at 11.

[68] MISO Northeast Transmission Customers Comments at 26.

[69] Joint Protestors Comments at 8-9.

Commission should direct Filing Parties to revise the proposed Tariff language such that a proposed MVP would have to demonstrate that it provides benefits to a minimum of three or more pricing zones so that a project receiving regional cost sharing provides regional benefits.

61. IPL states that the MVP proposal could result in shifting costs to the rest of the footprint without the promise of quantifiable and approximately equal benefits for IPL and others. IPL states that the Commission may consider requiring Midwest ISO to impose a cap on costs that can be shifted to certain ratepayers as a result of implementation of its cost allocation proposal and notes an instance in which the Commission affirmed that a cost-shift cap was warranted for a transition period.[70]

62. IPL also argues that the MVP proposal must be modified to limit the number of projects that can be approved and to include a budgeting mechanism for those projects. IPL states that there is now no such limit on the number of projects that can be built and, without such limits, load-serving entities cannot know how much they will be forced to pay. Thus, asserts IPL, the Commission should impose a budgeting process such that projects and costs can be limited or reviewed in some manner. IPL argues that it is the Commission's duty to protect consumers, and in approving a plan that favors investors with no protection for consumers, it is abandoning its traditional role under the FPA. IPL states that, while the argument may be made that consumers benefit because of increased reliability or increased access to markets, the utility industry has always recognized that there has to be some balance between building adequate facilities and minimizing costs to consumers. IPL asserts that approving this plan without a budget mechanism discards that traditional balance and is not in the public interest.[71]

63. Illinois Commission states that the unrestricted planning authority of Midwest ISO, in combination with the open-ended definition of benefits for the Total MVP Benefit-to-Cost Ratio, may induce overinvestment in transmission capacity, "especially

[70] IPL Comments at 31 (citing *Cal. Indep. Sys. Operator, Corp.*, Opinion No. 478, 109 FERC ¶ 61,301 (2004), *order on reh'g*, 111 FERC ¶ 61,337 (2005) (June 2, 2005 Rehearing Order)).

[71] *Id.* at 32-33.

given the low risk and high rate of return on transmission infrastructure and the risk shifting to load that the Commission has allowed under Order No. 679."[72]

64. Others make very specific requests. Michigan Commission asks the Commission to establish a rebuttable presumption that only the initial projected cost expectation for a project is subject to the cost recovery mechanism, so that the applicant must demonstrate that cost overruns are just and reasonable and could not have otherwise been anticipated.[73]

b. Criterion 1

i. Too Broad

65. Designated PJM Parties, MICH-CARE, Exelon, IMEA, Industrial Customers, Iowa Board, Iowa Advocate, MISO Northeast Transmission Customers, MPPA, and Wisconsin Commission express concern that MVPs are defined in a way that is too broad and/or vague. These parties believe that such vagueness will result in unfettered discretion and/or lead to overbuilding.[74] Industrial Customers believe that Filing Parties' proposal is a fundamental departure from traditional transmission planning principles by building transmission projects based upon pure speculation of generation siting, will lead to wasteful capital investment, and is contrary to the Commission's siting policies of Order No. 2003.[75]

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[72] Illinois Commission Comments at 30. *See Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[73] Michigan Commission Comments at 17.

[74] Industrial Customers Comments at 23-25; MPPA Comments at 10-11. *See also* Vectren South Comments at 4.

[75] IMEA Comments at 4-7. MPPA expresses a similar concern regarding how the use of projected flows from hypothetical resources could result in massive upgrades on facilities that may never see the flows projected in the analysis. To avoid this situation, MPPA recommends that the Commission require Midwest ISO to look at actual loads and at existing and under-construction resource effects in determining which lower-voltage facilities, if any, should qualify for inclusion in a MVP as "underbuild" facilities. MPPA Comments at 12-13.

66. Commenters ask that Criterion 1 be modified to exclude, or the Tariff language be revised to make more transparent, the determination of which projects will implement public policy. As IMEA understands Criterion 1, projects could potentially qualify merely on the supposition that they will meet future, as yet-to-be-defined public policy mandates. Iowa Advocate states that the proposal fails to include a requirement that the transmission project approved under Criterion 1 is actually needed to fulfill the policy mandate. PSEG Companies and MICH-CARE oppose the proposal's inclusion of a public policy component in the MVP criterion. MICH-CARE believes that the Commission first needs to define such standards for MVPs in the Transmission NOPR and, further, should not accept the proposal until a clear and reasonable bright line has been determined to clearly distinguish between MVPs and other network upgrades because their associated cost allocations are substantially different.

67. Illinois Commission adds that Midwest ISO fails to substantiate its claim that MVPs provide widespread public policy benefits, and further, Midwest ISO does not even define what it means by regional public policy benefits. As Illinois Commission reads it, nothing in Criterion 1 of the definition of MVPs requires that the public policy driver for the MVP be shown to be regional in nature – as evidenced by the fact that the term "multiple pricing zones" used in Criterion 2 and 3 is not even used in Criterion 1.[76]

68. Exelon states that, although justification for Criteria 2 and 3 have obvious metrics (cost benefit analyses and NERC reliability standards), there is no such obvious metric for transmission projects meant to satisfy public policy initiatives, such as renewable portfolio standards. Exelon suggests that a transmission project should meet Criterion 1 if it minimizes the sum of the above-market costs of the wind generation expected to be built and the cost of the transmission project.[77] MICH-CARE and MPPA argue that Criterion 1 should be modified to require that public policy projects provide delivery of energy to multiple zones, which should be defined as at least three or more pricing zones. Steel Producers claim that Midwest ISO has made no effort to demonstrate that Criterion 1 projects will have any multi-zonal benefits that warrant socializing their costs and state that they do not object to the inclusion of Criterion 1 projects, as long as those projects are subject to an objective, transparent analysis that evidences that costs are reasonably commensurate with the expected benefits.[78]

[76] Illinois Commission Comments at 20-21.

[77] Exelon Comments at 11-15. *See also* Iowa Board Comments at 11.

[78] Steel Producers Comments at 8-9.

69. MICH-CARE states that Criterion 1 does not allocate costs that are at least roughly commensurate with the benefits that are expected to accrue because MVP charges will be applied proportionally related to usage across regions, but the benefits of the projects will not be spread in the same manner. MICH-CARE believes that, for a project to qualify under Criterion 1, it needs to show that it would provide a positive benefit and meet the mandates or laws in each pricing zone and sub-region.[79]

70. MPPA also states that the proposal should be modified to explicitly require that Midwest ISO's planning studies demonstrate that 50 percent or more of the projected flow on the lines in a project is sourced from public purpose resources for the project to qualify as an MVP under Criterion 1.[80]

71. Alliant interprets the intent of the proposed Tariff language as being tied to policy mandates that are prevalent and generally consistent within the Midwest ISO region. It recommends that the proposed Tariff language be modified to specifically reflect that policy mandates used as the basis for MVP regional cost allocation treatment be prevalent within a majority of the Midwest ISO footprint for the policy mandate to be the basis for MVP regional cost allocation treatment.[81]

72. Michigan Commission states that projects qualifying under Criterion 1 should be able to deliver energy reliably and economically to support documented energy policy mandates. Where that is not the case, Michigan Commission requests that Midwest ISO should develop a different cost allocation to allow for more equitable sharing of costs to customers for MVPs that would be roughly commensurate with the benefits that they would receive.[82]

ii. <u>Too Limited</u>

73. Other parties find Criterion 1 to be vague but believe that the result will be that the implementation of designating MVPs will be too limited. NextEra believes that Criterion 1 could be interpreted to require a multi-state requirement for transmission projects and believes that the Tariff should be clarified to not have such a requirement. NextEra also states that the Tariff should specify that meeting the substantive requirements under the

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[79] MICH-CARE Comments at 8-10.

[80] MPPA Comments at 10-11. *See also* Vectren South Comments at 4.

[81] Alliant Comments at 13.

[82] Michigan Commission Comments at 11-12.

MVP criteria is not just a minimum threshold for MVP designation but will in fact cause the project to be designated as an MVP. NextEra also states that the Tariff should not prevent any qualified transmission developer from being able to propose, develop, and own an MVP, consistent with the applicable Midwest ISO procedures for the creation of an MVP.[83]

74. E.ON states that the following qualifier for Criterion 1, "the MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade," could unnecessarily preclude or delay the construction of transmission needed to meet state renewable portfolio standards. E.ON requests that the Commission either require Midwest ISO to delete the language or, alternatively: 1) explain how it intends to apply the qualifying language with specific examples and 2) provide additional Tariff language that lists the criteria that will be applied.[84]

75. ITC Companies-Wolverine argue that Criterion 1 should be expanded to include possible future policies, laws such as environmental mandates that affect the use of specific generation sources, and policy mandates related to demand response or smart grid. To be consistent with the Commission's Transmission NOPR, ITC Companies-Wolverine state, Criterion 1 should be revised to expressly provide for the consideration of current and likely future public policy mandates that may drive the need for transmission projects in determining eligibility for MVP status.[85]

76. AWEA-WOW, Midwest Generators, and Oak Creek suggest that there be a rebuttable presumption that network upgrades required for generator interconnection that are rated at or above 345 kV qualify as MVPs.[86] Such a presumption, they say, would provide greater clarity to which generator interconnection network upgrades would see regional cost sharing.

77. MidAmerican further asks that Criterion 1 be modified to provide for projects that meet documented public policy mandates or requirements beyond the energy policy mandates or laws providing for requirements such as no-carbon, low-carbon, or

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[83] NextEra Comments at 15-16. *See also* Integrys Comments at 5-6.

[84] E.ON Comments at 10-12.

[85] ITC Companies-Wolverine Comments at 11-14.

[86] AWEA-WOW Comments at 31; Midwest Generators Comments at 6-7; Oak Creek Comments at 10-11.

renewable portfolio standards. MidAmerican believes that this addition would provide appropriate incentives to encourage multi-state transmission construction.[87]

78. AMP is concerned that the proposed language may be unfairly limiting and requests that Midwest ISO be directed to clarify whether energy policy laws or mandates adopted by municipal authorities would be relevant for purposes of determining whether a transmission project qualifies as an MVP under Criterion 1. In AMP's view, because municipal utilities are sometimes not subject to state jurisdiction, refusing to recognize municipal laws or mandates could result in a municipal utility being obligated to share in the funding of energy policy mandates or laws adopted by other government entities, while at the same time being the sole funding source for its own energy policies. AMP believes that this potential result would plainly be unjust and unduly discriminatory.[88]

iii. Renewable Portfolio Standards

79. Illinois Commission, IPL, ABATE, Industrial Customers, MISO Northeast Transmission Customers, AMP, Iowa Advocate, MICH-CARE, and Steel Producers object to allocating the costs associated with state renewable portfolio standards to all load-serving entities on a postage-stamp basis because some load-serving entities are not subject to a renewable portfolio standard and should not be responsible for any associated costs. Illinois Commission argues that a reasonable cost allocation for transmission investments related to public policy initiatives, such as state renewable portfolio standards, would be proportional to the costs caused by each load-serving entity to satisfy its individual renewable portfolio standard requirement. It claims that allocating the same amount of costs to all load-serving entities on a postage-stamp basis is not roughly commensurate with the costs that they cause or the benefits that they receive because renewable portfolio standards are not reasonably consistent across all Midwest ISO states.[89]

80. In addition, some states require that their renewable portfolio standards be satisfied using renewable generation within a specific state, and according to Illinois

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[87] MidAmerican Comments at 22-23.

[88] AMP Comments at 14-15.

[89] For example, Illinois Commission states that each megawatt hour of load within a state with a 20-percent renewable portfolio standard causes twice as much transmission capacity as each megawatt hour of load within a state with a 10-percent standard. Illinois Commission Comments at 21.

Commission, these locational requirements can only increase the total cost of transmission needed to deliver renewable energy.[90]

81. IPL argues that the costs of state renewable portfolio standards should be socialized only to the load of those states that have imposed such obligations. IPL notes that Indiana chose to promote the integration of renewable resources consistent with its integrated resource planning program rather than mandating a specific renewable portfolio standard. IPL maintains that the transmission customers causing the expansions are those in states that have enacted renewable portfolio standards and are meeting those requirements with projects that are not located near existing transmission capacity. IPL concludes that allowing states to pass the cost of compliance with their own renewable portfolio requirements onto neighboring or distant jurisdictions would be inconsistent with Commission policy, including its recent order rejecting Midwest ISO's proposed socialization of the costs for operating reserves.[91]

82. ABATE contends that Midwest ISO should not socialize the cost of out-of-state MVPs because, once FirstEnergy withdraws from Midwest ISO and joins PJM in 2011, there will be only three 138 kV lines connecting Michigan utilities to the remaining Midwest ISO members, and the benefits of out-of-state MVPs to Michigan will not be roughly commensurate with the socialization of costs advocated by Midwest ISO.

83. MISO Northeast Transmission Customers argue that Midwest ISO's MVP proposal forces Michigan electric customers to subsidize out-of-state renewable projects from which they can, at best, receive a very limited benefit. According to MISO Northeast Transmission Customers, Michigan is the only state in Midwest ISO that has incorporated a 100-percent in-state siting requirement into its renewable portfolio standard, and Michigan load-serving entities have developed corresponding implementation plans. They argue that the MVP proposal would force Michigan customers to pay for transmission upgrades in other states that will not help Michigan load-serving entities to satisfy Michigan's renewable portfolio standard and that will compete with the development of wind generation within Michigan. MISO Northeast Transmission Customers contend that the MVP proposal requires them to make a much

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[90] Illinois Commission explains that total costs will increase to the extent that siting generation and building transmission would be cheaper in locations other than those dictated by locational requirements. *Id.* at 22.

[91] IPL Comments at 19 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,088, at P 48 (2010) (July 30, 2010 Order)). *See also* Industrial Customers Comments at 28; Indiana Commission Comments at 3; Iowa Advocate Comments at 10; AMP Comments at 13-14.

greater contribution to the costs of MVPs compared to the value of the benefits that they may realize.[92] They maintain that the proposal is inconsistent with cost causation principles because Michigan customers would subsidize projects caused by the higher renewable portfolio standards enacted in other states.[93] MISO Northeast Transmission Customers request that the MVP proposal be revised to designate the MISO Northeast Transmission Customers' region as a unique area such that its ratepayers would fully pay the costs of those MVPs necessary to meet Michigan's renewable portfolio standard but would not pay the costs of any MVPs constructed in other areas.[94]

iv. MVP Selection Process

84. Wisconsin Commission states that the Commission should require a structured process where states, Midwest ISO management and the Midwest ISO Board, Midwest ISO transmission owners, and generation owners work together to identify which projects are MVPs and worthy of the proposed cost allocation treatment with a significant state role in deciding what projects qualify as MVPs. Wisconsin Commission contends that states are the only RTO stakeholders that must balance the competing interests that make up the broad public interest, and state approval and siting are critical steps after any MVP designation is made.[95] Likewise, Michigan Commission states that the Commission could require Midwest ISO to continue its work to revise its Tariff to include a more detailed MVP planning and approval process that would increase the stakeholder

[92] MISO Northeast Transmission Customers Comments at 14 (citing MISO Northeast Transmission Customers Comments, Dotterweich Aff. at 4-13). The Dotterweich Affidavit states that, of the $4.1 billion in MVP starter projects listed by Midwest ISO, only the $510 million Michigan Thumb Project is located inside of MISO Northeast Transmission Customers' region. *Id.*, Dotterweich Aff. at 12.

[93] MISO Northeast Transmission Customers note that, while Michigan mandates that renewable resources provide 10 percent of their energy by 2015, Illinois and Minnesota require 25 percent by 2025, and Missouri requires 15 percent by 2021. *Id.* at 8 and 14, n.31.

[94] To effectuate their request, MISO Northeast Transmission Customers suggest specific language for Midwest ISO to incorporate into its Tariff. *See id.* at 15, n.33.

[95] Wisconsin Commission Comments at 8-9.

participation and review to ensure that MVPs are the most reliable and cost effective projects available in the short-term and the long-term.[96]

85. Illinois Commission argues that no process exists for a state to assess the reasonableness of facilities proposed to be built in other states within Midwest ISO. Nevertheless, each state will be required to bear its energy load-ratio share of MVP costs. Illinois Commission contends that the Commission cannot permit such an omission to stand. At a minimum, Illinois Commission recommends that the OMS Board have the opportunity to review and decide on Midwest ISO staff's proposals to move transmission projects with shared costs into MTEP Appendix A, prior to action by the Midwest ISO Board.[97]

86. According to OMS, Midwest ISO stated in its August 25 Planning Advisory Committee that it has no intention of moving MTEP projects from Appendix B to Appendix A on its own. OMS states that Midwest ISO expects that all such projects will be at the request of a transmission owner. OMS states that recent Commission decisions regarding the right of first refusal,[98] as well as its recent Transmission NOPR, could make the planning process more complicated as multiple transmission owners file for, and vie for, similar or the same transmission projects. OMS claims that Midwest ISO will need to develop procedures for how this new planning paradigm will work. At a minimum, OMS states that states will need to get more involved in the transmission planning processes at their host utilities, at merchant transmission construction projects, and at Midwest ISO. For example, OMS is interested in overseeing the need for MVPs and in ensuring the consistency of forecast methods and other types of analyses.[99]

87. IPL states that the first flaw related to the proposed cost allocation criteria is that a project need only meet one of the three criteria. Thus, IPL claims that it is possible that a project could be approved as an MVP and not have gone through the MTEP process. IPL

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[96] Michigan Commission Comments at 18. *See also* Indiana OUCC Comments at 4.

[97] Illinois Commission Comments at 44-45.

[98] OMS Comments at 13 (citing *Primary Power*, *LLC*, 131 FERC ¶ 61,015 (2010); *Central Transmission*, *LLC*, 131 FERC ¶ 61,243 (2010)).

[99] *Id.* at 13-14.

states that all projects that qualify for regional cost sharing should have to pass through the MTEP process.[100]

88. MISO Northeast Transmission Customers state that, although Midwest ISO proposes that MVP designation will be made through the MTEP, the transmission planning stakeholder process is insufficient to ensure that the costs imposed as the result of the inclusion of MVPs are just and reasonable for all Midwest ISO transmission customers.[101] In particular, MISO Northeast Transmission Customers state that the process for obtaining MVP designation does not reflect the goal of cost-effective transmission planning and includes a stakeholder review process that is merely advisory.[102]

89. OCC is concerned that transmission projects that do not provide substantial benefits will be approved as MVPs and points to the postage-stamp cost recovery of MVP costs in encouraging certain stakeholders to attempt to qualify transmission projects as MVPs to shift costs from themselves to consumers.[103] In order to prevent this, OCC requests Commission action to ensure that consumers have consistent presence and participation in the Midwest ISO stakeholder process. OCC suggests that this directive be fulfilled by a Midwest ISO-funded organization with an executive director who attends significant Midwest ISO meetings and meetings of interest to consumer interests. OCC claims that this director would serve as both a point of contact and representative for consumer advocates.[104]

90. IPL states that, in Order No. 890, the Commission stated that it "cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory

[100] IPL Comments at 34.

[101] MISO Northeast Transmission Customers Comments at 25.

[102] *Id.* at 25-26. They also argue that, because of the proposed socialization of MVP costs, to meaningfully participate in the MTEP process transmission customers will be forced to develop expertise and knowledge of systems far away from their home systems and will be forced to staff and participate in planning meetings far beyond their current levels.

[103] OCC Comments at 9-10.

[104] *Id.* at 10-11.

manner."[105] Accordingly, IPL states that, to "limit the opportunities for undue discrimination," the Commission required all RTOs to amend their tariffs to provide for a "coordinated, open, and transparent transmission planning process."[106] IPL claims that the Commission also clarified that openness meant that transmission customers and other stakeholders should be part of the process.[107] IPL states that, if the Commission has concerns with the MTEP process, then the solution is to implement targeted reforms to the MTEP process but not to allow for a complete sidestepping of such process. IPL states that the Commission should reaffirm the vitality of the MTEP process and require all MVPs to qualify through it. Thus, IPL recommends that the Commission clarify that, in any place where the July 15 Filing refers to the Midwest ISO transmission planning process or a similar variant, the parties should refer specifically to the MTEP process.[108]

91. NextEra states that it appears that the identification, designation, and construction of MVPs will depend on how the Midwest ISO transmission planning process unfolds at any given time. NextEra argues that Filing Parties' proposal provides little information on how this will occur, stating only that "all transmission projects that are approved for inclusion in Appendix A of the MTEP after July 15, 2010 will be carefully scrutinized and evaluated to determine cost sharing eligibility under the MVP cost allocation methodology."[109] NextEra states that there are numerous unresolved questions about how the transmission planning process will proceed with regard to MVPs, including how Midwest ISO and the Planning Advisory Committee will address the creation of MVPs and in particular how Midwest ISO and stakeholders participating in the transmission planning process would apply their discretion in formulating an MVP or determining whether a given transmission project might be an MVP.[110]

92. Finally, NextEra states that the planning process needs to be sufficiently forward-looking to meet reasonably expected requirements, which helps guard against undersized

[105] IPL Comments at 34 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422).

[106] *Id.* at 35 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435).

[107] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 440).

[108] *Id.*

[109] NextEra Comments at 13 (citing Filing Parties July 15, 2010 Filing, Transmittal Letter at 20).

[110] *Id.*

facilities. In addition, NextEra states that the Tariff should specify that meeting these substantive requirements is not just a minimum threshold for MVP designation but will, in fact, cause the project to be designated as an MVP, provided that other requirements are also met. NextEra argues that there should not be any discretion for decision makers in Midwest ISO's transmission planning process to deny a project MVP status, unless the applicable transmission needs are met through another MVP or another transmission project paid for through the same or substantially similar means.[111]

93. Midwest Generators state that it is essential that there be a defined time frame for completing the process under which MVPs are evaluated and designated as part of the Midwest ISO transmission planning process.[112] They argue that a known and approved plan, completed in a reasonable period of time, would lower timing risks and improve the ability of generation developers and other market participants to engage in their own planning and project development activities. Thus, Midwest Generators state that the Commission should require Midwest ISO to establish and adhere to specific deadlines that neither preclude meaningful stakeholder involvement nor otherwise threaten to impair the process for making classification decisions.[113]

94. Finally, AWEA-WOW ask the Commission to urge Midwest ISO to move the first set of starter projects forward for identification as MVPs in the 2011 MTEP process and no later than the 2012 MTEP.[114] Midwest Generators, Iberdrola, and Oak Creek make similar requests,[115] and Iberdrola also asks that the first annual report detail Midwest ISO's efforts to meet this goal.[116] AWEA-WOW also ask that the Commission encourage Midwest ISO to assign or hire adequate staffing resources to expeditiously move these projects toward construction.[117]

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[111] *Id.* at 15-16.

[112] Midwest Generators Comments at 7.

[113] *Id.* at 7-8.

[114] AWEA-WOW Comments at 29.

[115] Iberdrola Comments at 25; Midwest Generators Comments at 8; Oak Creek Comments at 11.

[116] Iberdrola Comments at 25.

[117] AWEA-WOW Comments at 29.

v. **Michigan Thumb Project[118] and Out-of-Cycle Review**

95. Several parties provide comments on a specific project, the Michigan Thumb Project. This project was recently approved by the Midwest ISO Board in an out-of-cycle MTEP proposal on August 19, 2010. Should the Commission approve the MVP proposal to be effective July 16, 2010 as proposed, this project would be one of the first to qualify under Criterion 1 of the proposal. The project is designated to meet the renewable requirements of the state of Michigan, which requires that its renewable standards be met with in-state resources.

96. Exelon, FirstEnergy, and Vectren South assert that the Michigan Thumb Project is driven solely by Michigan's renewable portfolio standard.[119] Exelon and FirstEnergy argue that Midwest ISO approved the project early, as an "out-of-cycle" request, to satisfy Michigan's 10-percent renewable portfolio standard that will be phased in from 2013 to 2015.[120] FirstEnergy contends that Midwest ISO had no authority under the Midwest ISO Tariff to approve the "out-of-cycle" request to consider the Michigan Thumb Project as an MVP and, thus, violated the filed rate doctrine and Commission precedent. FirstEnergy adds that Midwest ISO recognized in a July 2010 presentation that the Michigan renewable portfolio standard is the impetus for the Michigan Thumb Project.[121] Vectren South argues that Criterion 1 does not include any regional benefit

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[118] The Michigan Thumb Project is rated at 345 kV, is included in the MVP Starter List, and has an estimated cost of $510 million. Witness Moeller states that this project is a result of the State of Michigan Clean, Renewable, and Efficient Energy Act (Act No. 295),which requires identification of existing or new transmission infrastructure necessary to deliver the maximum (4,236 MW) and minimum (2,367 MW) wind energy production potential within the Michigan Thumb region. Witness Moeller states that the proposed transmission project is required to be of appropriate capability to enable the wind potential of the wind energy resource zone to be realized, and wind farms totaling 1,260 MW of generation in the current Midwest ISO generation interconnection queue in the Michigan Thumb region further compel the urgent need to approve a prudent plan that fits all needs. *See* Filing Parties July 15, 2010 Filing, Tab J and Moeller Test. at 21.

[119] *See, e.g.*, Vectren South Comments at 4 (citing Filing Parties July 15, 2010 Filing, Moeller Test. at 20-21).

[120] *See, e.g.*, FirstEnergy Comments at 38 (citing FirstEnergy Comments, Att. A, Fuerst Declaration at P 58).

[121] *Id.* at 38-39 (citing, *e.g.*, Midwest ISO, July 2010 Out-of-Cycle Presentation at 6, *available at* http://bit.ly/ctFjHb).

component to reflect that some facilities, such as the Michigan Thumb Project, are built to meet energy policy mandates and benefit only the specific zone where the facilities are located.

97. Exelon, FirstEnergy, IPL, and Vectren South argue that the proposed cost allocation for the Michigan Thumb Project is inconsistent with cost causation principles. Exelon maintains that, to the extent that there are production cost benefits outside of Michigan, it is extremely unlikely that any such benefits would be roughly commensurate with the costs imposed on loads as far distant as Missouri or the Dakotas. Exelon notes that transmission cost allocation should follow transmission planning,[122] and it claims that the costs of the Michigan Thumb Project should be socialized only to the extent that there are demonstrated benefits outside of Michigan. IPL argues that no transmission expansion would be necessary but for Michigan's renewable portfolio standard and its requirement that it be met using only in-state resources. FirstEnergy and Vectren South contend that load and exports that derive no benefit from policy-mandated facilities will share in the costs of those facilities, which is inconsistent with cost causation principles.

98. Exelon and FirstEnergy argue that Midwest ISO has not shown that the benefits of the Michigan Thumb Project extend beyond Michigan. They contend that, while Midwest ISO has purported to show cost savings associated with the Michigan Thumb Project, Midwest ISO has not documented that those cost savings go beyond Michigan. FirstEnergy maintains that any cost savings associated with the Michigan Thumb Project will be experienced in Michigan because the wind resources supported by the project would be built in Michigan and loads in Michigan will use that wind energy to satisfy their state renewable portfolio standard.[123] Exelon argues that Midwest ISO has not detailed whether the analysis of the project's cost savings was consistent with existing state laws and regulations (including rate caps) or was based on future anticipated laws and regulations.[124]

99. Similarly, FirstEnergy and IPL argue that Midwest ISO has not shown that a portion of the costs of the Michigan Thumb Project should be allocated to their customers. FirstEnergy states that Midwest ISO intends to assign 11.5 percent of the project's annual costs (nearly $16 million per year) to load in the ATSI zone but only

[122] Exelon Comments at 9 (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 5).

[123] FirstEnergy Comments at 39 (citing FirstEnergy Comments, Att. C, Farley Declaration at P 48-49).

[124] Exelon Comments at 9, n.16.

16 percent of those costs to load in Michigan.[125] FirstEnergy contends that the ATSI zone has a negligible impact on the transmission system in the Michigan Thumb, noting that the ATSI zone is located in Ohio and Pennsylvania, not Michigan.[126] Therefore, FirstEnergy contends that the ATSI zone did not necessitate the Michigan Thumb Project and will not realize any corresponding reliability benefits. FirstEnergy adds that the ATSI zone will not enjoy any public policy benefits because the zone has no obligation to satisfy Michigan's renewable portfolio standard.[127] FirstEnergy contends that, consistent with cost causation principles, the record must contain substantial evidence showing that the proposed allocation of costs for new MVPs is "roughly commensurate" with the affected customers' respective contributions to the underlying need for lines.[128] FirstEnergy concludes that Midwest ISO has made no such showing.

100. IPL argues that Midwest ISO proposes an unreasonable shift of the cost of the Michigan Thumb Project to IPL's customers. IPL states that Midwest ISO intends to assign IPL 2.7 percent of the Michigan Thumb Project's costs, which would increase IPL's current annual revenue requirement by 19.5 percent. IPL adds that its own studies estimate that the financial impact to IPL of the all projects under the MVP proposal will total $100 million by 2024.[129] IPL contends that Midwest ISO has not shown that IPL's customers necessitated the facilities or would benefit from the Michigan Thumb Project in a manner commensurate with the corresponding cost assignment. IPL concludes that the Commission should reject or substantially modify Filing Parties' proposal.

101. Illinois Commission states that the Michigan Thumb Project illustrates why the Midwest ISO out-of-cycle request process needs to be modified. Illinois Commission points out that section I.B.1.C of Attachment FF states:

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[125] FirstEnergy Comments at 40 (citing July 2010 Out-of-Cycle Presentation at 34).

[126] *Id.* at 39 (citing FirstEnergy Comments, Att. B, Gass Declaration at P 5-6, 16).

[127] FirstEnergy notes that Ohio has a renewable portfolio standard that requires at least half of the renewable resources to be located in Ohio.

[128] FirstEnergy Comments at 40 (citing, *e.g.*, *Midwest ISO Transmission Owners*, 373 F.3d at 1368-1369).

[129] IPL states that its estimate of the cost shifts is "extremely conservative because Midwest ISO has provided no cost estimates of the scope of [MVPs] that may result under the proposal." IPL Comments at 20 (citing IPL Comments, Att. A, Kempker Aff. at 8).

> Out-of-Cycle Review of Transmission Owner Plans: In the event that a [Midwest ISO] [t]ransmission [o]wner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless [Midwest ISO] performs an expedited review of the impacts of the project, [Midwest ISO] shall use a streamlined approval process for reviewing and approving projects proposed by the [Midwest ISO] [t]ransmission [o]wners so that decisions will be provided to the [o]wner within thirty (30) days of the projects submittal to [] Midwest ISO unless a longer review period is mutually agreed upon.[130]

102. Illinois Commission states that the out-of-cycle request provision is short on details, and it is concerned that the out-of-cycle request will be used by transmission owners to circumvent the traditional MTEP process. Thus, Illinois Commission requests that the Commission direct Midwest ISO to revise the current Tariff language so that only reliability projects or projects where transmission owners agree to share the costs of the project are eligible for out-of-cycle review.[131]

c. <u>Criterion 2 and Criterion 3</u>

103. Illinois Commission specifically faults: 1) the inclusion of the "any other" economic or financial benefit category, arguing that this language would allow Midwest ISO to exercise unlimited discretion; 2) that the qualification that a project provide benefits to more than one zone is likely to be satisfied by a project that nonetheless fails to provide benefits commensurate with a postage-stamp cost allocation; and 3) that any meaning to the proposed Total MVP Benefit-to-Cost Ratio test included in the proposed Tariff language is mitigated by the fact that the test does not indicate whether the benefits are distributed across the Midwest ISO region. Finally, Illinois Commission states that the analysis necessary to qualify a transmission project under Criterion 2 would allow Midwest ISO to allocate the costs of a transmission expansion project to load-serving entities based on measurable benefits (that could vary by zone), yet Midwest ISO would still choose to allocate those costs on a postage-stamp basis.

104. IPL suggests that the Commission direct Filing Parties to modify their proposal so that MVP benefits must be shown to occur in a larger portion of the Midwest ISO footprint or to simply allocate the costs to those zones that are demonstrated to benefit from the project.

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[130] Illinois Commission Comments at 46 (citing Midwest ISO Tariff, Fourth Revised Vol. No. 1, Att. FF, section I.B.1.C).

[131] *Id.* at 47.

105. Iowa Advocate opines that Criterion 2 virtually eliminates any rigor that might have been in the benefit-to-cost ratio test because projects are only required to show no losses rather than having to demonstrate benefits. IMEA agrees, asserting that a 1:1 benefit-to-cost ratio does not provide any assurances that there will be any net benefit from a proposed project.

106. Iowa Board states that Criterion 2 and Criterion 3 should be strengthened and clarified to ensure that only projects that are truly regional in nature are designated as MVPs. In addition, Iowa Board states that the benefit-to-cost ratio should be raised from the proposed ratio of 1:1 to 1.25:1.

107. Michigan Commission requests that the Commission reject the use of Criterion 2 as a criterion to qualify as an MVP. In the alternative, Michigan Commission requests that Filing Parties be required to modify the proposed benefit-to-cost ratio test from 1:1 to 1.25:1 to better reflect a project's regional impact as well as making it consistent with the ratio for Cross Border Market Efficiency Projects between Midwest ISO and PJM.

108. Iowa Advocate argues that basing the forecasted benefits for MVPs on a 20-year period makes it likely that the projected benefits would be questionable at best. Specifically, Iowa Advocate points to the Commission's RECB II Order where Midwest ISO explained that, "for a project to be included in MTEP as a [Market Efficiency Project,] it must have a benefit/cost ratio [] that uses a sliding scale to reflect the increased uncertainty of projects with longer construction horizons."[132] Wisconsin Industrials similarly state that the RECB II proceeding recognized that, the farther out the in-service date, the more uncertainty there is regarding the amount of benefits the project will provide. While Wisconsin Industrials understand that some parties believe that the current sliding scale benefit-to-cost ratio test associated with the RECB II proceeding is too rigorous, the answer is not to move so far in the other direction as to make the qualifying threshold too low.

109. ATC seeks clarification that, when a project is being considered under Criterion 3, the cost of the transmission facilities needed to address the reliability issue should not be counted against the economic benefits in considering the benefits-to-cost ratio. When comparing a project's cost to total benefits, ATC avers, the benefits should be compared only to the costs of the "economic" portion of the project (i.e., the costs in excess of the cost of the transmission facilities needed to address the reliability issue).

110. OMS supports Criterion 2 as proposed by Filing Parties. OMS suggests that a benefit-to-cost ratio of 1:1 may not be high enough to ensure that a project will provide

[132] Iowa Advocate Comments at 11 (citing RECB II Order, 118 FERC ¶ 61,209).

projected benefits but that a ratio of 1.25:1 may be too high and would preclude projects from receiving regional cost allocation.

111. Integrys states that a stringent application of Criterion 2 and Criterion 3 could result in few network upgrades achieving MVP status and thereby undermine the purpose of the MVP cost allocation methodology.

112. Iowa Advocate argues that Criterion 3 essentially adds the same 1:1 benefit-to-cost ratio test required for economic projects to reliability projects and that, due to the uncertainty related to predicting benefits over a 20-year time span, the proposed test does not adequately protect against such uncertainty.

113. OCC believes that Criterion 2 and Criterion 3 should not be allowed to stand separate from Criterion 1. OCC argues that it is necessary to set a high bar for projects to receive postage-stamp cost allocation, such as the proposed MVP methodology. Therefore, OCC requests that the Commission require an MVP to meet both Criterion 1 and either Criterion 2 or Criterion 3.[133] NIPSCO requests that the Commission change the definition of MVPs so that MVPs could be either: 1) projects built for public policy reasons but limited to public policy requirements applicable to Midwest ISO load; or 2) projects that meet both a reliability requirement and an economic benefit (benefit-to-cost-ratio of 1.25:1) for all of Midwest ISO.[134]

d. Voltage Criteria

114. Many parties argue that the proposed 100 kV minimum voltage threshold for a project to be considered for MVP status is too low. AMP also argues that Commission precedent does not support Filing Parties' proposed regional cost sharing of lower-voltage facilities. AMP notes that, in the RECB I Order, the Commission accepted Midwest ISO's proposal for Baseline Reliability Projects that explicitly precluded projects less than 345 kV from receiving a regional cost allocation.[135] Similarly, Illinois Commission believes the 100 kV threshold should be rejected, noting that the lowest voltage line under the control of Midwest ISO is 69 kV, and therefore, a 100 kV

[133] OCC Comments at 6-7. *See also* Industrial Customers Comments at 19.

[134] NIPSCO Comments at 6-7.

[135] AMP Comments at 10. *See also* Illinois Commission Comments at 32.

threshold would include an overwhelming majority of new transmission facilities in the Midwest ISO footprint.[136]

115. MISO Northeast Transmission Customers believe that the MVP definition should not include "underbuild" transmission in a socialized cost allocation methodology, and they request that the Commission require Midwest ISO to preclude the inclusion of transmission facilities or project component costs below 345kV in the MVP cost allocation.[137] MPPA contends that the limits that presently apply to "underbuild" for Regionally Beneficial Projects in Attachment FF are reasonable and should continue under the proposed MVP criteria.[138]

116. For example, AMP argues that Filing Parties' premise that facilities operating at voltages as low as 100 kV can provide regional benefits is incorrect and that, even if it were correct, Filing Parties have failed to demonstrate that the benefits received by each Midwest ISO zone are at least "roughly commensurate" with the costs imposed on the zone simply by reciting a list of potential benefits that may or may not actually materialize.[139]

117. Michigan Commission states that it believes that Filing Parties' request to include facilities operating at voltages at or above 100 kV does not satisfy the cost causation

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[136] Illinois Commission Comments at 32.

[137] MISO Northeast Transmission Customers Comments at 30.

[138] MPPA Comments at 13-14. MPPA states that Attachment FF currently provides that:

> ". . . [Regionally Beneficial Projects] may include any lower voltage facilities of 100 kV or above that collectively constitute less than fifty percent (50%) of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio threshold for the project as established in [s]ection II.B.1.c, or that otherwise are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project."

Id. at 14 (citing Midwest ISO Tariff, Fourth Rev. Vol. No. 1, Original Sheet No. 3443).

[139] AMP Comments at 9.

principles articulated by the Commission or the courts, as the usage of these facilities are too local to provide regional benefits commensurate with the expected regional cost allocation. Thus, Michigan Commission requests that the Commission direct Filing Parties to amend the definition of MVP to include a minimum voltage threshold consistent with its neighboring RTOs (300 kV in SPP and 500 kV in PJM).[140]

e. No Direct Cost Assignment of MVPs to Generators

i. Cost Causation and Equity

118. Illinois Commission and Industrial Customers state that generators whose interconnections are enabled by MVPs will benefit from the MVP proposal.[141] Illinois Commission states that the proposal creates undue discrimination among generators and between generators and load. If the MVP proposal is not rejected, and if the interconnecting generators are not allocated a share of the MVP costs directly, then, states Illinois Commission, the Commission should direct Midwest ISO to develop a proposal whereby generators whose interconnection to the system is enabled by an MVP would reimburse, over time, those entities required to bear the burden of the MVP costs. Industrial Customers state that Filing Parties acknowledge that the MVP starter projects have been proposed primarily to facilitate the interconnection of new wind generation facilities. Industrial Customers state that this admission and the proposal's cost assignment would not be permitted under the "but for" standard to interconnect generators and to allocate costs.[142] PJM states that failing to allocate to the generator the

[140] Michigan Commission Comments at 12-13.

[141] Illinois Commission Comments at 33-38; Industrial Customers Comments at 21-23 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 22).

[142] In this vein, Industrial Customers (Comments at 32-37) argue that there is tension between the present filing, which would exclude generators from paying for MVPs, and a Midwest ISO compliance filing pending before the Commission in Docket No. ER09-1581-004 (Community Wind). In that case, the Commission directed Midwest ISO to remove language that allocated the entire cost of the Brookings Line (a starter MVP in this proceeding), but left open the possibility that a portion of the costs of the Brookings Line could be allocated to these generation projects, commensurate with the portion of the upgrade that would not be necessary but for their interconnection. Acciona argues that, if the proposal is approved, then the Commission should determine in this docket that the Brookings Line qualifies as an MVP (or, if further study is required, at least evaluate the issue in this docket). Iberdrola asks the Commission to clarify that its decision in the Community Wind case is without prejudice to Midwest ISO ultimately determining that the Brookings Line is an MVP and allocating 100 percent of its costs in

(continued…)

costs of transmission enhancements that would not have been needed "but for" the generating project, would have implications for other regions in the country.[143]

119. Hoosier-SIPC and ABATE similarly state that Midwest ISO fails to allocate MVP costs to new renewable generators and, in doing so, grossly misapplies the principles of cost causation.[144]

120. Wisconsin Industrials argue that direct assignment is important because not all new generators will have power purchase agreements and that such entities would nevertheless benefit from the MVPs. By directly assigning the costs to new generators, the costs will be directed to the "right load."[145] Finally, Wisconsin Industrials note the shared network upgrade aspect of the proposal and state that there is no reason why this sharing approach could not be used to cover all costs caused by generator interconnection projects, including those that are now being proposed as MVPs.[146]

121. Hoosier-SIPC and MidAmerican further state that the proposed MVP cost allocation ignores input from the OMS CARP working group and call on the Commission to require Midwest ISO to revise its proposal to assign some costs of the MVPs to generator owners and point to the CARP approach.[147]

122. While some in OMS (Indiana, Michigan, Minnesota, North Dakota, and South Dakota) view the lack of assignment of MVP costs to generators to be balanced by the continuation of 90-percent participant funding, others (Illinois, Iowa, Missouri, Montana, and Ohio) view the lack of assignment of MVP costs to generators to be inconsistent with cost causation principles (i.e., remote generators cause MVP costs and benefit from being able to sell energy and from gaining tax advantages). The state commissions that fault

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accordance with the instant proposal.

[143] PJM Comments at 8.

[144] Hoosier-SIPC Comments at 18-20; ABATE Comments at 4.

[145] *See also* Alliant Comments at 9-11 discussing the importance of the "right load" paying. Alliant states that, if the Commission's decision or Midwest ISO's application of the proposed Tariff exclude charges to exports, a design that includes injection charges to generators merits more consideration.

[146] Wisconsin Industrials Comments at 18.

[147] Hoosier-SIPC Comments at 18-20, Blake Aff. at 19; MidAmerican Comments at 9-11.

the proposal in this regard point to a report by the Midwest ISO Independent Market Monitor in support of the view that generators should be charged for some MVP costs.[148] Thus the "balancing" represented by the proposal, say these parties, remains insufficient: generators should directly bear some of the costs of all network upgrades associated with their interconnections.[149]

123. Iowa Board recommends that the Commission require some allocation of MVP costs to generators, perhaps 10 percent, as a compromise between Midwest ISO's zero-percent proposal and CARP's 20-percent proposal. Iowa Board states, however, that legal and spill-over benefit concerns seem to argue that the access charge would be applied to all generators, in contrast to the Independent Market Monitor's suggestion to apply such a charge mainly to new generators. If the Commission agrees with Iowa Board and imposes such a requirement, Iowa Board believes that the states should have a role in affirming or restricting any election made by a transmission owner to reimburse the MVP costs allocated to generators.[150]

124. MidAmerican asserts that equity considerations and other factors should be considered when evaluating whether to assign MVP costs to generators.[151] MidAmerican faults Midwest ISO witness Ramey's justification that such allocation to generators would produce generation-related market distortions identified in the LECG Report. MidAmerican states that such market distortions are not significant or are at least no more significant than the market impacts of the approach proposed by Filing Parties.[152]

125. Southwestern also objects to generators not being assigned MVP costs, stating that market distortions are precisely the result when those who benefit from a project are exempted from the allocation of the costs of that project. Southwestern argues that allocating these costs to load-serving entities, like that of Southwestern, which has acquired sufficient long-term generation to supply its needs and has made substantial

[148] *See, e.g.*, Illinois Commission Comments at 34 (citing Illinois Commission Comments at Appendix A, *Presentation of Dr. David Patton Provided to the Midwest ISO RECB Task Force on June 10, 2010*).

[149] *See, e.g.*, OMS Comments at 4-8.

[150] Iowa Board Comments at 3-7.

[151] MidAmerican Comments at 18.

[152] *Id.* at 15-17 (citing the LECG Report).

payments for transmission interconnection and upgrades needed to accommodate this generation, creates market distortions.[153]

126. E.ON, Joint Protestors, and AWEA-WOW support the proposal not to assign MVP costs directly to generators.[154]

ii. <u>Proposal Undermines Efficient Generator Siting</u>

127. AWEA-WOW, MISO Northeast Transmission Customers, Midwest TDUs, and Indiana OUCC are concerned that Filing Parties' proposal may result in inefficient siting of generation.[155]

128. MISO Northeast Transmission Customers argue that Midwest ISO's cost allocation proposal sends a clear, albeit inappropriate, price signal to would-be wind farm developers by removing almost all cost consequences of their siting decisions. MISO Northeast Transmission Customers argue that a more fully-integrated siting and development analysis would consider not only the suitability of a given site from the standpoint of the available wind profile, forecasted production, land use and other environmental considerations and the like, but also the cost and availability of transmission.[156] MISO Northeast Transmission Customers point to the potential to develop significant amounts of wind generation in the Thumb region of Michigan and, absent an MVP proposal like Filing Parties', an analysis of a Thumb wind project versus a North Dakota wind project, for example, would consider a variety of factors, including the respective wind profiles of each locale, transmission losses, and the availability and cost of necessary transmission.[157] MISO Northeast Transmission Customers argue that, for delivery to load in Michigan, it is possible that a Thumb project would look more

[153] Southwestern Comments at 11.

[154] *See* E.ON Comments at 10; Joint Protestors Comments at 34-36; AWEA-WOW Comments at 22 and 23.

[155] *See*, *e.g.*, MISO Northeast Transmission Customers Comments at 30-33; Midwest TDUs Comments at 6-9; Indiana OUCC Comments at 4.

[156] MISO Northeast Transmission Customers Comments at 31.

[157] *Id.* at 31-32.

attractive than a North Dakota project because of the relative transmission costs, even if the North Dakota wind profile is more attractive.[158]

129. Further, MISO Northeast Transmission Customers argue that the MVP proposal operates more like a tax than a transmission charge and certainly does not act like the price signal that the Commission contemplated at the outset of Midwest ISO's market development.[159] MISO Northeast Transmission Customers contend that Midwest ISO is a transmission operator, and it is not Midwest ISO that should be deciding what kind of generation gets built nor should Midwest ISO decide where that generation gets built. MISO Northeast Transmission Customers assert that Midwest ISO must return to its role as operator of the transmission platform upon which a competitive market can operate instead of biasing the analysis of generation alternatives by deciding that new transmission investment should be treated differently (via socialization) than all other transmission investments.

130. Midwest TDUs argue that exempting generators from MVP costs gives them a strong financial incentive to favor transmission solutions that assume heavier reliance on wind in the western portions of Midwest ISO (with the highest capacity factors), even if it would be more cost effective (taking account of all associated transmission and other costs) to build the generation closer to load.[160] Such generators would then pressure Midwest ISO to designate any transmission facilities needed to deliver their energy to load centers as MVPs.[161] Midwest TDUs state that Midwest ISO's Independent Market Monitor particularly identified the problem of inefficient siting in its comments on Midwest ISO's proposed approach.

131. Lastly, Midwest TDUs state that the one shortcoming of the proposed cost allocation from an efficiency perspective is that the costs of new transmission are not allocated more directly to the *new* generation that is creating the demand for the new transmission. Midwest TDUs contend that this is sub-optimal because it does not allow investors in the new resources to recognize the total costs of their siting decisions.

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[158] *Id.* at 32. *See also* Midwest TDUs Comments at 7 ("properly taking the cost of the associated transmission upgrades into account could result in a very different and more efficient geographic distribution of renewable resources that relies more heavily on local resources with lower total delivered costs").

[159] MISO Northeast Transmission Customers Comments at 32.

[160] Midwest TDUs Comments at 6.

[161] *Id.* at 8.

Therefore, Midwest TDUs maintain that investors will not have efficient incentives to build their new generation in locations that minimize their total entry costs (including the costs of *both* the generation and transmission).[162]

132. Industrial Customers state that a failure to align cost responsibility and cost causation will result in generators having no incentive to discipline their siting decisions and will also impede a proper identification of the most cost-effective generation solutions. This principle applies equally well for a single coal-fired generation facility making tradeoffs in its proximity to fuel and load as it does for large numbers of wind resources in Midwest ISO's interconnection queue. For customers, this results in a "lose-lose" proposition.

133. Wisconsin Electric also calls for MVP costs to be allocated to new generation to incent efficient siting.[163] Wisconsin Industrials and MICH-CARE similarly state that assigning no MVP costs to new generators will result in the lack of a pricing signal for efficient siting and speculative transmission investment.[164]

f. Transmission Studies, Cost Causation, and the *Illinois Commerce Commission* Decision

134. Acciona, ATC, AWEA-WOW, Gamesa, Iberdrola, ITC Companies-Wolverine, Oak Creek, OMS, and Xcel all state that Midwest ISO has presented sufficient evidence to support its claim that MVP-like projects will provide region-wide benefits and therefore should have their costs allocated across the Midwest ISO footprint. ITC Companies-Wolverine state that, under the MVP proposal, cost allocation would be roughly commensurate with benefits received, meeting the requirements of the Seventh

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[162] *Id.* at 6 (citing Summary of Midwest ISO's Independent Market Monitor Comments on Cost Allocation Proposal from June 10, 2010 Meeting, *available at* http://www.midwestiso.org/publish/Document/345da0_1299503ccb2_-7f5f0a48324a/Summary%20of%20IMM%20Comments%20on%20Cost%20Allocation%20Proposal%20from%20June%2010%20Meeting.pdf?action=download&_property=Attachment). Midwest TDUs note that the Independent Market Monitor's comments were received after the May 19, 2010 meeting at which the Midwest ISO Advisory Committee adopted a motion that included the concept of allocating 100 percent of the costs of certain transmission projects to load through a demand charge. *Id.* at 6-7.

[163] Wisconsin Electric Comments at 3.

[164] Wisconsin Industrials Comments at 16-17; MICH-CARE Comments at 7.

Circuit Court in *Illinois Commerce Commission*.[165] AWEA-WOW and Acciona state that Midwest ISO has shown that the MVP starter projects will reduce congestion, further public policy goals, and reduce production costs across the region. AWEA-WOW note that, since these studies do not quantify all of the benefits from transmission lines, such as a greater ability to meet policy requirements, increased system reliability, improved operating conditions, and a reduction in generator interconnection costs, the overall financial benefits would likely be significantly larger than these estimates.[166] Further, AWEA-WOW note that Midwest ISO studies show that the transmission facilities in the long-term transmission plan show 80-percent regional usage.[167] Xcel states that Commission precedent has established, and the courts have upheld, that the determination of the beneficiaries of transmission facilities, and the allocation of costs to those beneficiaries, need not be precise.[168]

135. Iberdrola argues that, consistent with court and Commission precedent, Midwest ISO does not need to "calculate a specific economic or dollar-for-dollar benefit that any one entity receives as a result of the identification of MVPs."[169] According to Iberdrola, Midwest ISO has shown that the MVP cost allocation assigns costs that are roughly commensurate with the expected benefits, and this meets Midwest ISO's burden. Iberdrola states that the Commission's recent order regarding cost allocation in the Southwest Power Pool (SPP) confirms that Midwest ISO is only required to demonstrate that assigned costs are roughly commensurate with expected benefits over time.[170]

136. OMS states that it is important to note that MVPs have benefits other than making the interconnection of renewable resources easier for renewable energy developers. OMS states that MVPs will also enhance the transmission system and will better enable the interconnection of all sources of new generation, no matter the technology or location. According to OMS, MVPs will increase the transfer capability of the transmission

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[165] ITC Companies-Wolverine Comments at 16-17 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[166] AWEA-WOW Comments at 17-18.

[167] *Id.* at 19.

[168] Xcel Comments at 12-13 (citing *Midwest ISO Transmission Owners*, 373 F.3d at 1368-69).

[169] Iberdrola Comments at 13.

[170] *Id.* at 14 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 76).

system, which will allow more access to supply choices to deliver energy to a wider range of load, both within and outside of Midwest ISO. OMS states that, on average, this should result in lower delivered-energy costs, since transfer capability enhances the system, not just for a few or some, but for all hours of the day, every day of the year. OMS states that the predicted economic benefits of MVPs can be estimated in terms of load cost savings, adjusted production cost savings, and market congestion benefits.[171]

137. Southwestern emphasizes that it is not opposed to the types of projects that would qualify for MVP cost allocation and is only concerned about what, it states, is a deviation from cost causation principles.[172] According to Southwestern, Midwest ISO ignored traditional cost causation factors in designing the MVP cost allocation and the proposal will only benefit a select group – mainly, generation owners interconnected to the Midwest ISO grid as a result of MVPs and the load-serving affiliates of certain transmission owners.[173]

138. FirstEnergy, Illinois Commission, Industrial Customers, IPL,[174] Iowa Advocate, MICH-CARE, MPPA, NIPSCO, Hoosier-SIPC, Southwestern, and Wisconsin Industrials raise several objections to the MVP proposal: 1) Filing Parties did not provide the actual studies; 2) both the expected benefits and the transmission usage studies are flawed; 3) there is no demonstration that individual pricing zones or load-serving entities will see net benefits; and 4) the starter projects were aggregated to analyze net-benefits rather than analyzed individually. Protestors also dispute the estimated benefits claimed by Midwest ISO and state that Midwest ISO's proposal is not consistent with the Seventh Circuit Court's opinion in *Illinois Commerce Commission*.[175]

[171] OMS Comments at 3-4.

[172] Southwestern Comments at 5-6.

[173] *Id.* at 10.

[174] IPL states that this proposal is no different from another proposal in which the Commission ordered that Midwest ISO could not allocate 100 percent of the cost of operating reserves region-wide. IPL Comments at 24 (citing July 30, 2010 Order, 132 FERC ¶ 61,088 at P 48).

[175] *Illinois Commerce Commission*, 576 F.3d at 476.

139. Illinois Commission objects to Midwest ISO's characterization of MVPs as inherently regional and necessarily providing regional benefits.[176] Illinois Commission notes that the OMS CARP and Midwest ISO RECB transmission usage studies that are cited only studied lines rated at 345 kV and above, yet here Midwest ISO proposes to extend the definition of MVPs down to 100 kV.[177]

140. Illinois Commission and IPL object to Midwest ISO not providing the studies on which it bases its claims of region-wide benefits and state that the benefits Midwest ISO claims are vague.[178] Illinois Commission objects to Midwest ISO claiming regional-wide benefits and supporting this claim with empirical estimates that come from sources that are not cited in the July 15 Filing. Illinois Commission states that this means that the accuracy of the estimates cannot be independently verified. Further, Illinois Commission and Hoosier-SIPC state that there is no empirical estimation of how the positive-adjusted production cost savings accrue to planning regions, transmission owner zones, or load-serving entities.[179] Again, with no empirical evidence or cited source of such evidence, Illinois Commission states that it is not possible to verify this claim. Illinois Commission makes similar arguments regarding Midwest ISO's estimated load cost savings, transmission loss savings, decreased need for installed capacity, and ability to integrate more renewable generation.[180] Illinois Commission also argues that the value of Auction Revenue Rights and Financial Transmission Rights must also be included in any calculation of the benefits and costs of a proposed MVP.[181]

141. Industrial Customers agree that the proposed cost sharing is unsupported. They state that Moeller's testimony is unsupported by any evidence. They contend that Lawhorn's testimony shows that load cost savings could be *de minimus* or even negative and provides no evidence that production cost savings, load cost savings, or reduced losses will be distributed region-wide.[182] Industrial Customers assert that the value

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[176] Illinois Commission Comments at 6-7, 13-15. *See also* IPL Comments at 21-22.

[177] Illinois Commission Comments at 8-9.

[178] *Id.* at 6; IPL Comments at 21-22.

[179] Hoosier-SIPC Comments at 3-4.

[180] Illinois Commission Comments at 10. *See also* MICH-CARE Comments at 12.

[181] Illinois Commission Comments at 12.

[182] Industrial Customers Comments at 13-16.

Lawhorn presents for avoided capacity exceeds the estimated costs of new entry that Midwest ISO has requested in other proceedings as well as recent estimates from Midwest ISO's Independent Market Monitor.[183] Regarding Curran's testimony on the reliability benefits accruing from MVPs, Industrial Customers state that such a claim must be supported, not just claimed, as any transmission upgrade can be claimed to have reliability benefits. MICH-CARE disagrees with the argument that the MVP proposal would decrease line losses and believes that Filing Parties should place a detailed analysis to support this claim into the record. It states that the purpose of the MVP proposal is to move energy across longer distances from the west side of the region to the east. MICH-CARE states that MVPs could increase line losses because such losses tend to increase as energy is transported over longer distances.

142. Illinois Commission provides data on five transmission projects identified as possible starter projects and for which there is available load cost savings data, delineated by planning region, from the 2010 MTEP study. This sample, says Illinois Commission, shows that benefits are not spread evenly across the Midwest ISO footprint. In one case, Illinois Commission states that the eastern planning region derives positive load cost savings, while the central and western regions see increases in LMPs. Two other cases show overwhelming benefits flowing to the central region, Illinois Commission states, with the western region seeing increases in LMPs in both cases and the eastern planning region also losing in one case and gaining very little in the other. According to Illinois Commission, in only one of the five cases do the benefits outweigh the costs; taken as a group the costs outweigh the benefits for these five projects. Illinois Commission states that, of the last two, one shows positive benefits to all while the other shows all regions facing increased LMPs.[184] Illinois Commission also presents results for production cost savings that show very different results. Taken as a group, Illinois Commission claims that these five projects result in reduced production costs in all planning regions. Illinois Commission states that, individually, each project results in lower production costs across the Midwest ISO region. Illinois Commission states that the eastern planning region sees decreased production costs in all but one case, and the central and western planning regions do in three of five cases. Illinois Commission argues that, while production cost savings may be a good measure of productive efficiency, it says nothing about how those cost savings accrue to market participants.[185] Illinois Commission argues that the MVP

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[183] *Id.* at 16 (citing Midwest ISO November 19, 2008 Filing, Docket No. ER08-394-007; Midwest ISO August 2, 2010 Filing, Docket No. ER10-2090-000).

[184] Illinois Commission Comments at 14, Table 1.

[185] *Id.* at 15, Table 2. *See also* Hoosier-SPIC Comments at 8 (citing *Illinois Commerce Commission*, 576 F.3d at 476-477).

proposal would violate cost causation principles and is also prohibited by the FPA and the courts.[186]

143. FirstEnergy protests Midwest ISO presenting a package of starter projects to show that MVPs will be regionally beneficial. The benefits of these projects were aggregated in order to show their benefits, while the projects would need to be approved individually, according to FirstEnergy. FirstEnergy states that Midwest ISO has shown only that this collection of projects, as a group, satisfies the MVP criteria and justifies the regional cost allocation. FirstEnergy contends that the "MVP [p]roposal's cost allocation does not comport with the cost causation principle."[187]

144. Industrial Customers and Iowa Advocate question load growth estimates and other inputs into the expected benefits studies. Industrial Customers state that the load data used by Midwest ISO in its five scenarios used to analyze usage patterns is out of date and therefore unreliable. They state that, in a study commissioned by Midwest ISO, virtually all peak load growth by 2030 was estimated to be mitigated by demand response and energy efficiency improvements.[188] Based on this, Industrial Customers state that it is unreasonable to use Midwest ISO's studies to identify what regions may be expected to receive benefits from such (potentially unnecessary) projects. Iowa Advocate questions the assumption that utilities in the eastern region will purchase such quantities of power from remote sources to justify charging customers throughout the Midwest ISO region for projects of the scope being proposed. It states that the viability of the long-distance transaction concept lies primarily in the possibility that the federal government will adopt legislation that in some manner will result in remote energy becoming cost effective in the east. Yet it is well known that states wish to avoid importing energy into their states, according to Iowa Advocate.[189]

145. Several protestors question the validity of Midwest ISO's transmission usage studies. Protestors state that, in the transmission usage study cited by Midwest ISO, the definitions of "local" and "regional" undermine the premise on which Midwest ISO is

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[186] *Id.* at 47-51.

[187] FirstEnergy Comments at 37.

[188] Industrial Customers Comments at 20-21 (citing Global Energy Partners, LLC, *Assessment of Demand Response and Energy Efficiency Potential for Midwest ISO*, *available at* http://www.midwestmarket.org/publish/Document/ff748_12aaa1280c5_-7fe50a48324a?rev=1).

[189] Iowa Advocate Comments at 15.

relying to assert the regional nature of MVPs. A flow being regional only means that it spanned at least two pricing zones, something Illinois Commission states is insufficient for claiming that the flow is truly regional. Hoosier-SIPC similarly protest Midwest ISO's definition of regional.[190]

146. Illinois Commission, MPPA, MISO Northeast Transmission Customers, IPL, and Industrial Customers all raise objections to Filing Parties' proposal in light of the *Illinois Commerce Commission* decision. According to Illinois Commission, there are several similarities between the MVP cost allocation proposal and PJM's postage-stamp cost allocation that was rejected by the Seventh Circuit Court. Illinois Commission claims that both proposals seek to allocate the costs of new transmission on a postage-stamp basis, justifying them on the basis that the proposed transmission projects would provide region-wide benefits. Illinois Commission believes that both proposals fail to provide sufficient analysis or evidence to support claims of region-wide benefits.[191] According to MPPA, Midwest ISO erroneously equates benefit receipt with cost causation in its proposal, and Filing Parties fail to support their claim that all MVPs benefit load and that all load benefits in a roughly-equivalent manner. Although MPPA acknowledges that the courts have accepted, to some extent, the notion that beneficiaries are deemed to have caused the cost, MPPA believes that Filing Parties' proposal takes this too far.[192] MISO Northeast Transmission Customers make a similar argument, stating that the MVP proposal fails to meet the cost causation requirement by equating benefits with cost causation and by making unsupportable claims about the alleged correspondence of charges and benefits. Accordingly, they contend that the proposed MVP cost allocation would allow Midwest ISO to assess MVP charges on all load, regardless of the benefits that customers may or may not receive from a specific MVP.[193]

147. IPL states that the MVP proposal is not consistent with *Illinois Commerce Commission* because it is skewed to benefit larger transmission owners. As a smaller transmission owner that is less likely to have projects large enough to qualify for the proposed cost sharing, IPL states, its cost burden would outweigh prospective benefits.[194]

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[190] Hoosier-SIPC Comments at 9.

[191] Illinois Commission Comments at 32-33.

[192] MPPA Comments at 5-9.

[193] MISO Northeast Transmission Customers Comments at 11-15.

[194] IPL Comments at 12-15.

148. Industrial Customers state that "beneficiary pays" is a well-established principle that Midwest ISO essentially ignores in the MVP proposal. According to Industrial Customers, this model of cost allocation is substantively different from, and results in greater economic efficiency than, cost allocation models that socialize transmission costs, which distort the economic incentives of participants by insulating the beneficiaries from the full costs of a given project. Industrial Customers argue that the MVP proposal socializes costs too broadly, thereby failing to align the allocation of costs with beneficiaries. Specifically, Industrial Customers argue that the MVP proposal dramatically shifts costs to load that are currently allocated to interconnecting generation resources. Industrial Customers state that Midwest ISO's studies do not show that this shift would result in broad, regional benefits.

149. Wisconsin Industrials, Hoosier-SIPC, IPL, MICH-CARE, and MPPA state that Midwest ISO provides no evidence regarding how benefits and MVP costs are commensurate for their loads. Wisconsin Industrials state that Midwest ISO provides no evidence that Wisconsin will be allocated a share of MVP costs that is commensurate with its expected benefits. Based on the MVP starter projects, Wisconsin Industrials expects that the entire state will be allocated 15 percent of the currently-projected $4.6 billion cost, amounting to $686 million, $240 million of which will be paid by Wisconsin's industrial sector.[195] While Midwest ISO presents an estimation of future benefits, Wisconsin Industrials state that Wisconsin rate payers will not see them. First, they state that the savings ranges Mr. Lawhorn addresses are on a footprint-wide basis and fail to reflect savings specifically to the Wisconsin ratepayer. Second, Wisconsin Industrials state that, while specifically identifying the value of the benefits received through the program are not possible, it is possible to conclude that Wisconsin will receive less than the 15 percent in costs that it would be expected to pay.[196]

150. IPL objects to Midwest ISO's statements that MVP benefits will accrue generally across the footprint, while only attributing those benefits to three planning regions. IPL states that, because planning zones are large and encompass many states, it can be the case that in any one zone only some states receive benefits, while all pay. It cites the central planning zone as an example, where Illinois and Missouri each have renewable portfolio standards, but Indiana does not. IPL states that Midwest ISO has the data that show benefits by pricing zone.[197]

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[195] Wisconsin Industrials Comments at 11.

[196] *Id.* at 12.

[197] IPL Comments at 22-24.

151. MICH-CARE states that it is likely that residential customers who live far away from an MVP would receive little or no benefit, yet they would be required to help pay for the project under the MVP proposal. For Michigan, MICH-CARE explains, this is especially acute because of the state's relative isolation from the bulk of the Midwest ISO system.[198] Michigan, MPPA states, will represent approximately 20 percent of the load in Midwest ISO and thus under Midwest ISO's proposal pay approximately 20 percent of the costs of all MVPs. Since Michigan law requires them to rely on in-state renewable resources, MPPA states, it cannot receive such benefits.[199]

2. Filing Parties' Answer

152. Filing Parties explain that the MVP category limits region-wide cost recovery to regionally planned facilities that must provide more than local benefits. Moreover, states Midwest ISO, while any single project can benefit all users by enhancing the integrated regional network, MVPs as a category plainly will provide broad regional benefits, as over time they will enhance all parts of the Midwest ISO transmission system. Filing Parties state that Midwest ISO has made clear to stakeholders that MVPs will be reviewed on a "portfolio" basis, taking into account the synergistic effects of individual qualifying MVPs and approving the set of MVPs that maximize overall regional value. Filing Parties generally respond that if the criteria were more restrictive, the development of regional transmission would be hampered. [200]

153. Filing Parties' explain that Criterion 1 needs to be worded broadly, because it must take into account that laws differ from state to state and could change in the future. Filing Parties' note that 11 of the 13 states in Midwest ISO's footprint have documented renewable portfolio standards. Criterion 1 clearly provides a regional benefit to Midwest ISO that is likely to increase in the future. Even for projects driven primarily by public policy, other drivers (i.e., Criterion 2 and Criterion 3) and benefits will likely be present.

154. In response to E.ON's argument that the language, "in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade," introduces economic and reliability considerations into what should be a pure public policy criterion, Filing Parties' explain that reliability and economic considerations cannot be divorced from analysis of upgrades to the integrated transmission network. They argue that planners are required to consider the impact on

[198] MICH-CARE Comments at 5-6.

[199] MPPA Comments at 8.

[200] Filing Parties October 18, 2010 Answer at 15-16 and 27.

reliability and the overall value provided by a project, particularly when compared to its alternative.

155. In response to Wisconsin Industrials, Filing Parties clarify that an MVP is not meant to be a substitute for a GIP under Criterion 1. Unlike GIPs, which are driven by interconnection requests, MVPs would be derived from a regional planning process.

156. Filing Parties argue that although not every single state within the Midwest ISO region has adopted a renewable portfolio standard, and those states that do have them have different requirements, the fact that 11 of the 13 states have a renewable portfolio standard represents a broad consensus on the need for renewable resources. Further, Filing Parties also believe that there is reason to expect a federal renewable portfolio standard may be adopted in the near future, which would clearly affect the entire Midwest ISO region. According to Filing Parties, thousands of megawatts of new generating capacity and related transmission additions will be necessary to meet the requirements of these policies, and it would be unreasonable to omit consideration of them from the MVP criteria.

157. Further, Filing Parties claim that even those states without a renewable portfolio standard or that mandate that their renewable portfolio standard requirements be met with in-state resources will derive significant reliability and economic benefits from MVPs, because even MVPs driven by public policy requirements will strengthen and enhance the transmission network. In response to comments singling out Michigan as a state that will not receive MVP benefits and should therefore be allocated little or no MVP-related costs, Filing Parties claim that Michigan is expected to receive substantial benefits from MVPs. Filing Parties point out that the expected production cost savings reported in the Filing are higher for the East Planning Region, which includes Michigan, than for the other two Midwest ISO Planning Regions. As Filing Parties have consistently argued, MVPs will confer system-wide benefits on all users, including Michigan, of the transmission system. Finally, Filing Parties point out that it is reasonable for Michigan to share the costs of other states' MVPs, just as it is reasonable for those states to share the costs of Michigan's MVPs (such as the Michigan Thumb Project).[201]

158. On the process of identifying MVPs, Filing Parties state that Midwest ISO executes its transmission planning process in an open and transparent fashion in accordance with Order No. 890, and that MVPs will move through the same Commission-approved process.[202] They add that Midwest ISO's Commission-approved

[201] *Id*. at 17-18.

[202] *Id*. at 40.

planning process offers multiple opportunities for all stakeholders, including transmission owners, state regulators and generators, to provide input and feedback on all aspects of a study beginning with planning assumptions through the final results.

159. With regard to the Michigan Thumb Project referenced by multiple commenters, Filing Parties emphasize that, although approval of the project was advanced, it was considered and evaluated by Midwest ISO planners as only one of a group of potential MVPs considered for approval. All of these projects combined form a portfolio of projects that provide public policy benefits for the entire Midwest ISO region. Filing Parties explain that although some projects, such as the Michigan Thumb Project, support certain areas more than others, the entire portfolio of projects is expected to provide regionally distributed benefits.[203]

160. Filing Parties also argue that their proposed benefit-to-cost ratio of 1.0 is appropriate. Filing Parties point out that it is common for benefits to increase and costs to decrease over the life of a project and therefore it is likely that a project will "generate value beyond 20 years, thus a 1.0 benefit-to-cost ratio evaluated over the first 20 years of a project's life provides a sufficient cushion to address any concerns over a benefit-to-cost threshold of 1.0."[204]

161. With respect to the arguments put forward that the MVP criteria do not adequately ensure that benefits are regional in nature, Filing Parties state that qualifying projects will be shown to have quantifiable economic benefits in multiple pricing zones and to provide multiple types of economic benefits.

162. On the purpose of Criterion 3, Filing Parties reiterate that projects that qualify under this criterion will facilitate the development of transmission infrastructure that provides economic value across multiple pricing zones while simultaneously addressing at least one current or imminent violation of a NERC or Regional Entity reliability standard. For example, Filing Parties state that it is appropriate for a project that solves projected NERC violations in multiple pricing zones at a lower annual revenue requirement than the combined annual revenue requirement of multiple, bottom-up reliability projects that would be necessary to address the projected violations individually, to be eligible for regional cost sharing.

163. Regarding the voltage cutoff, Filing Parties state that despite representations made by protestors, 100 kV represents the minimum size transmission facility over which

[203] *Id.* at 15-16.

[204] *Id.* at 32.

Midwest ISO generally exercises functional control and that it is appropriate for Midwest ISO to evaluate all facilities over which it exercises functional control to determine whether they qualify for MVP cost allocation.[205] Filing Parties also note that irrespective of a project's voltage level, a transmission facility that has been determined by Midwest ISO, through its MTEP process, to provide regional benefits as an MVP should be eligible to receive MVP cost allocation. Filing Parties assert that increasing the 100 kV threshold could cause significant problems. For example, if the threshold were raised to 230 kV and a project operating at a voltage below 230 kV (e.g., 161 kV, etc.) were demonstrated to be the most prudent solution to meet incremental public policy requirements or to enhance regional value, such a project would be unnecessarily and inappropriately excluded from MVP consideration based solely on the higher voltage threshold. Indeed, there are a number of areas within the Midwest ISO footprint where 230 kV transmission is used regionally and provides regional benefits, and where such facilities represent the maximum voltage used to provide transmission service. Thus, "the fact a transmission facility is 'only' rated at 100 kV is not and should not be, in and of itself, determinative of whether the facility provides regional benefits and is appropriately classified as an MVP."[206]

164. Under their proposal, Filing Parties state that MVPs may include upgrades to facilities below the 100 kV minimum voltage threshold (i.e., underbuild) if the MVP results in transmission issues with these facilities that otherwise would not occur but for the MVP facility. Thus, Filing Parties aver, it is appropriate to include these underbuild upgrades within the scope of the MVP as long as upgrades are evaluated and identified in the MVP study process as not being require but for the proposed MVP facility. Furthermore, Filing Parties contend that it would be unjust and unreasonable to assign the costs of the underbuild facilities solely to the local zone where they are constructed,

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[205] *Id.* at 37 (citing Agreement of Transmission Facilities Owners to Organize Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation, Midwest ISO, FERC Electric Tariff, Rate Schedule No. 1, Appendix H (Transmission System Facilities), first paragraph, sub-paragraph no. 1 (Transmission Owners Agreement); Midwest ISO Tariff, Fourth Revised Vol. No. 1, section 1.55 (definition of "Bulk Electric System")). Some 69 kV facilities, which are below the minimum threshold, may be transferred to Midwest ISO's functional control to the extent that they serve transmission functions, but facilities at or below such voltage levels are generally used for local, rather than regional, transmission. However, to the extent that such facilities are required as part of the "underbuild," and thus contribute to regional reliability, they will be deemed part of the MVP facilities for purposes of cost allocation.

[206] *Id.* at 38.

because it is the MVP facility that is causing the need for those underbuild facilities, not the local loads. On the suggestion to create a rebuttable presumption that generator interconnection network upgrades of 345 kV and above qualify as MVP, Filing Parties respond that such a rebuttable presumption defeats the purpose of other MVP requirements.[207]

165. Filing Parties disagree with protestors' arguments that the cost-sharing for the MVP category is not supported by Commission and court precedent, particularly the Seventh Circuit's ruling in *Illinois Commerce Commission.* According to Filing Parties, court and Commission precedent support broad cost recovery where the benefits are broadly shared, which is the case with their proposed cost recovery for the MVP category. Filing Parties' explain that in *Illinois Commerce Commission*, the court advised that the Commission only needed "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with the assigned costs. Furthermore, Filing Parties state, the courts and the Commission have consistently approved rolled-in pricing (i.e., charging all users of the transmission network as opposed to only specific identified users).[208]

166. Filing Parties point out that the Commission recently relied on these precedents to approve SPP's proposed postage-stamp recovery. The same considerations that the Commission relied on to accept SPP's cost recovery (i.e., users of an integrated system change over time and the overriding commonality in the centrally-planned, regionally integrated high-voltage transmission network) support region-wide recovery for the proposed MVPs, Filing Parties state. Filing Parties claim that like the "highway" category in SPP, the new MVP category defines a subset of regionally planned facilities that provide benefits extending well beyond any single zone, enhance the regional integrated network, and provide benefits to all users of that regional integrated network.[209]

167. Filing Parties also take issue with certain protestors' claim that the proposed MVP category is similar to the cost allocation proposal that was remanded in *Illinois Commerce Commission*. Filing Parties believe that the circumstances are quite different

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[207] *Id*. at 63.

[208] *Id*. at 9.

[209] *Id.* at 10-12 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252). In SPP's proposal, projects rated at 300 kV and higher are allocated 100-percent regionally. Projects rated between 100 kV and 300 kV receive 33-percent regional cost sharing and 67-percent zonal allocation.

in this proceeding; most importantly, the court in *Illinois Commerce Commission* found that the Commission had not presented even a rough estimate of the likely benefits to network users or of the contribution that high-voltage facilities would likely make to the reliability of PJM's network. In contrast, Filing Parties point to the substantial evidence they provided in their filing to support the proposed region-wide cost sharing.[210]

168. In response to protestors' criticisms of Filing Parties' estimation of the expected benefits of MVPs, Filing Parties offer several rebuttals. First, Filing Parties answer that each individual MVP should not be viewed in isolation, but as part of a portfolio of projects. Filing Parties state that Midwest ISO made clear to stakeholders that MVPs will be reviewed on a portfolio basis, taking into account the synergistic effects of individual qualifying MVPs, and approving the set of MVPs that maximize overall regional value.[211]

169. Second, Filing Parties state that criticism of the studies used to support the proposal does not undercut the evidence provided by those studies. In response to Illinois Commission's criticism of the definition of "regional," Filing Parties respond that the definition is logical, in that if a local impact is one that occurs where the facility is located, any other must be regional. Further, the definition used is comparable to that accepted in the SPP Highway-Byway proposal where the Commission found that inter-zonal impacts above a certain threshold indicated the level of a facility's support for regional power flows.[212] As to Illinois Commission's objection to a 100kV cut-off, Filing Parties state that using 100kV allows for underbuild and is required under a "but-for" analysis.[213] In response to IPL and others who criticized the Regional Generation Outlet Study, Filing Parties state that the Regional Generation Outlet Study projects are exactly the projects this proposal is aimed at, transmission facilities necessary to meet renewable portfolio standard goals. Further, Filing Parties state that the support provided through the Regional Generation Outlet Study surpasses the amount of information typically provided to the Commission in such cases. And while IPL cites a roughly even split between local and regional use in the central planning sub-region, Filing Parties state

[210] *Id.* at 12-14.

[211] *Id.* at 15 (citing 2011 Candidate MVP Study Scope of Work Initial Draft at sections 2.2, 2.3 (Sep. 22, 2010), *available at* http://www.midwestiso.org/publish/Document/35f529_12b1fc99e5a_-7f650a48324a?rev=2).

[212] *Id.* at 20 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 73).

[213] *Id.*

that this analysis is mis-applied here, because that study looked at the how the existing transmission system is used, not at how these new facilities would be used.[214]

170. While protestors criticize the production cost study's analysis of savings based on the established Midwest ISO planning sub-regions, arguing that the studies should instead be performed on a zonal basis, Filing Parties answer that the previously approved Midwest ISO Tariff already expressly prescribes cost-benefit analyses for those same sub-regions to determine transmission cost allocations. In response to Industrial Customers' protest that load forecasts used in the studies were too high, Filing Parties note that these forecasts were provided by the load-serving entities. In response to criticism of the estimate of the cost of new entry, Filing Parties reply that $960,000 represents a generic per MW capital cost roughly between that of a Combustion Turbine or Combined Cycle unit. They state that this value is a fair, even conservative, estimate of the capital cost of new capacity given the current Midwest ISO generator interconnection queue.[215] Finally, as the Commission stated in the SPP Highway-Byway Order, Filing Parties state that just because some parties would choose to use different methods or inputs for determining the benefits of MVPs, that does not mean that Filing Parties' methods are unreasonable or should be rejected.[216]

3. <u>Other Answers</u>

171. Designated PJM Parties state that assertions of "public policy" benefits are inadequate to distinguish the benefits of one MVP versus another and to demonstrate how such benefits are distributed among entities within and adjacent to Midwest ISO.

172. In response to FirstEnergy, ITC Companies contend that Midwest ISO's out-of-cycle approval of the Michigan Thumb Project complied with the transmission planning process provided in the Midwest ISO Tariff and business practices manuals.[217] ITC Companies assert that the out-of-cycle review was imperative to allow ITC Companies to submit its siting application and to meet Michigan's renewable portfolio standard, which

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[214] *Id.* at 21.

[215] *Id.* at 22.

[216] *Id.* at 22-23 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 74).

[217] ITC Companies September 27, 2010 Answer at 4-5 (citing Midwest ISO Tariff, Fourth Revised Vol. No. 1, Att. FF, section I.B.1.c, First Revised Sheet No. 3432; Midwest ISO Business Practices Manual No. 20, Transmission Planning, section 7.1.6).

begins in 2013. ITC Companies add that Midwest ISO stakeholders fully participated in the review process for the project.

173. MISO Northeast Transmission Customers agree with commenters' argument that the benefits of the Michigan Thumb Project would be received, primarily, by load within Michigan. For this reason, they state that Midwest ISO should not require load outside of Michigan to pay for the Michigan Thumb Project, and thus, Midwest ISO should not require load in Michigan to pay for MVPs that do not benefit Michigan loads. MISO Northeast Transmission Customers also contend, however, that the Michigan Thumb Project could help load-serving entities outside of Michigan to satisfy their states' renewable energy mandates, since most states do not have in-state siting requirements.[218] MISO Northeast Transmission Customers argue that, if the Commission does not require Midwest ISO to carve out the Michigan Thumb region for MVP cost allocation purposes, the Michigan Thumb Project should remain one of the MVP starter projects because it would satisfy Criterion 1.

174. In contrast, ITC Companies argue that the Michigan Thumb Project would provide regional benefits sufficient to satisfy Criterion 1. ITC Companies claim that the project is not designed solely to meet Michigan's renewable portfolio standard, stating that the out-of-cycle analysis of the project documented that it would benefit the entire Midwest ISO transmission system by reducing load and production costs, avoiding wind generation curtailment, and reducing carbon dioxide emissions.[219]

175. ITC Companies disagree with MISO Northeast Transmission Customers' argument that Michigan should be treated as a separate area for transmission planning and cost allocation purposes. ITC Companies maintain that they fundamentally challenge the scope of Midwest ISO by essentially proposing a separate Michigan RTO. ITC Companies state that such a proposal would necessitate a separate proceeding. ITC Companies also contend that they take too narrow a view of MVP benefits based on a snapshot of the system today and ignore the integrated nature of the transmission grid.

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[218] In particular, they assert that Michigan load-serving entities would need approximately 1,500 MW of the 4,400 MW of potential wind development in the Michigan Thumb region to satisfy Michigan's renewable portfolio standard, leaving the remainder for use by load-serving entities in other states. MISO Northeast Transmission Customers September 27, 2010 Answer at 4, n.4.

[219] ITC Companies September 27, 2010 Answer at 6, n.14 (citing Out of Cycle Project 3168 Project Justification: Michigan Region 4 Thumb Loop (Draft) at 88, 91). ITC Companies add that the project was also evaluated by stakeholders as part of the Regional Generation Outlet Study and, as a result, is considered an MVP starter project.

ITC Companies assert that Midwest ISO serves multiple functions, and entities should not be allowed to enjoy all of the benefits while accepting only some of the attendant obligations. ITC Companies add that carving out Michigan from the MVP cost allocation would balkanize the planning process, which is incompatible with the Commission's effort to strengthen regional planning in the Transmission NOPR.

176. MISO Northeast Transmission Customers claim that Filing Parties' answer did not address the issues raised by their earlier protest. Specifically, MISO Northeast Transmission Customers are concerned that Michigan will not receive benefits commensurate with the costs of MVPs, and that Michigan will be subsidizing the costs of other states' MVPs.[220]

177. In its answer, PSEG Companies believe that, given the likelihood of changes in both public policies and technology that will impact the grid, transmission planning for public policy could actually undermine the reliability benefits that Midwest ISO claims. PSEG Companies also note that, contrary to Midwest ISO's claim in its answer, the addition of wind resources to the grid may actually impede, not promote, reliability. Finally, PSEG Companies note that Midwest ISO in its answer failed to support its claim that economic benefits in the form of lower production costs or lower capacity costs will result from public policy compliance in the form of more renewable generation.[221]

178. MISO Northeast Transmission Customers state that Filing Parties did not provide any clarity to the definition of MVPs. They also claim that Filing Parties' answer is ambiguous and fails to describe how the MVP definition will be applied.[222] E.ON reiterates its concern over the inclusion of Tariff language including reliability and economic considerations in Criterion 1, and argues that, Filing Parties did not sufficiently address E.ON's concerns in their answer.[223]

179. AWEA-WOW respond to protestors' claims that Midwest ISO has not provided sufficient evidence of the benefits provided by MVPs by reiterating Midwest ISO's evidence and providing its own. Using an economic impact model,[224] AWEA-WOW

[220] MISO Northeast Transmission Customers November 1, 2010 Answer.

[221] PSEG Companies November 2, 2010 Answer at 3-7.

[222] MISO Northeast Transmission Customers November 1, 2010 Answer at 6-7.

[223] E.ON November 2, 2010 Answer at 27-30.

[224] This economic impact model is intended to estimate the magnitude of the job and economic impacts over a period of time due to some economic injection, in this case,

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estimate, among other things, that total economic benefit from the MVP starter projects between 2012-2036, measured in 2010 dollars, is more than $20 billion. Individual states are estimated to receive benefits equal to anywhere from $0.8 billion for Missouri, to $5.6 billion for Michigan. AWEA-WOW also estimates that more than 60,000 jobs will be created for the construction and operation of these facilities. AWEA-WOW also estimates reduced emissions and water conservation.

180. Designated PJM Parties claim that Filing Parties' answer lacks the requisite evidence to satisfy cost causation principles and to establish that the MVP cost allocation proposal is just, reasonable, and not unduly discriminatory.[225]

181. CMTC responds to Filing Parties' statements that MVPs will be evaluated as part of a portfolio. Specifically, CMTC states that the concept of a portfolio approach to evaluating MVPs was only briefly discussed at a stakeholder meeting in September 2010 and, more important, is not actually contained in the instant proposal. CMTC states that, as written, the three criteria must be met by each MVP, not by a portfolio of MVPs.[226] Further, it states that the benefit-cost ratio outlined in the proposal also indicates that MVPs are to be evaluated individually, citing the use of the phrases "a specific Multi Value Project," and "the Multi Value Project."[227] Based on this, CMTC states that it is not reasonable to base any just and reasonableness determination on MVPs being evaluated as a portfolio since this is not proposed by Filing Parties, no matter any statements made in their October 18, 2010 Answer.

182. CMTC also responds to AWEA-WOW's analysis of the economic impact of the MVPs. CMTC states that the benefits shown by AWEA-WOW are general regional benefits that cannot be included in this analysis per the Commission's precedent; the Commission has stated that a statement of generalized system benefits is not enough to

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the building and maintenance of transmission lines and installation and operation of power generation stations. The analysis does not include the impact of the construction of the wind turbines themselves. AWEA-WOW used the Jobs and Economic Development Impact model (JEDI) developed by the National Renewable Energy Laboratories. *See* AWEA-WOW November 4, 2010 Answer at 8-15.

[225] Designated PJM Parties November 2, 2010 Answer at 4

[226] CMTC November 8, 2010 Answer at 5.

[227] *Id*. at 6 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Second Revised Sheet No. 293).

support cost allocation.[228] CMTC also notes that AWEA-WOW concede that the benefits they calculate are largely speculative and do not demonstrate specific benefits to any particular region or state. CMTC states that "WOW is essentially admitting that all critical inputs and assumptions for the JEDI model are inherently speculative and unfounded," because there is no way to know exactly which of the MVP lines will be built. Thus, according to CMTC, the caveats that are attached to the JEDI analysis nullify any value that could be derived from the JEDI results. Therefore, CMTC states that the JEDI analysis provided by AWEA-WOW has no probative value and cannot be afforded any weight by the Commission.[229]

183. EPSA answers MidAmerican by noting that MidAmerican supported the CARP proposal which would have assigned 20 percent of MVP costs to new and existing generation and that the CARP proposal was ultimately rejected in Midwest ISO's stakeholder process. EPSA states that neither MidAmerican – nor any other party - has supported the assignment of MVP costs to existing generators which EPSA compares to a tax.[230]

184. MidAmerican responds to EPSA that because MVPs are intended to result in a robust interconnected transmission system, and all loads and generators will use and benefit from such a system, it is appropriate to allocate MVP costs to all loads and generators. MidAmerican takes issue with EPSA's characterization of MidAmerican's position as supporting a tax on generators. Rather, MidAmerican believes it is appropriate to allocate a portion of MVP costs to generators, in the same way that MVP costs would be allocated to loads under the proposal of Filing Parties (i.e., allocating MVP costs to all generators cannot be a "tax" if a charge to all loads, that is intended to produce the same result, is an "allocation").[231]

4. <u>Calls for Annual Reporting</u>

185. Several commenters suggest that the Commission monitor the progress made toward identifying MVPs. AWEA-WOW, Alliant, Iberdrola, IPL, Wisconsin Electric, OMS, and OCC suggest that the Commission require Midwest ISO to submit annual

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[228] *Id*. at 8 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[229] *Id*. at 8-9.

[230] EPSA September 27, 2010 Answer at 3-5.

[231] MidAmerican October 8, 2010 Answer at 3.

reports or performance reviews.[232] Similarly, Integrys suggests semi-annual filings or, in the alternative, semi-annual posting on Midwest ISO's website[233] and, E.ON suggests quarterly filings.[234] Commenters suggest that the reports include information as to the number of approved MVPs and details on the associated cost allocation, the adequacy of the transmission planning process in identifying MVPs and any challenges involved in that process, whether the contingency window is effective, and any issues related to the coordination of the transmission planning process and generator interconnection processes.

186. In addition, AWEA-WOW request that the Commission require Midwest ISO to file with the Commission the approved 2012 MTEP transmission plan to ensure that the set of Starter Projects were approved by the Midwest ISO Board and, if not, the Commission should require an explanation for Midwest ISO's failure to meet those deadlines and should consider requiring changes to the MVP criteria and transmission planning process to address any obstacles to MVP approval.[235] AWEA-WOW also ask the Commission to require Midwest ISO to include in annual informational reports information identifying upgrades approved as MVPs and upgrades directly assigned to generators. AWEA-WOW assert that if necessary transmission construction does not materialize, both the GIP cost allocation methodology and the MVP criteria should be revisited.[236]

187. Illinois Commission also requests the Commission to require that Midwest ISO's annual MTEP report and associated project cost allocations be submitted with the Commission for review and approval under section 205 of the Federal Power Act.[237]

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[232] AWEA-WOW Comments at 29-30, 35; Alliant Comments at 11; Iberdrola Comments at 24-25; IPL Comments at 30-31; Wisconsin Electric Comments at 4-5; OMS Comments at 13-14; OCC Comments at 8.

[233] Integrys Comments at 7-9.

[234] E.ON Comments at 15-16.

[235] AWEA-WOW Comments at 30.

[236] *Id.* at 40-41.

[237] Illinois Commission Comments at 40-45. Illinois Commission argues that Midwest ISO's transmission expansion plan and the associated cost allocations constitute classification[s], practices, and regulations "affecting rates and charges" that are required, under section 205(c) of the FPA, to be filed with the Commission (citing FPA, section 205(c)).

Illinois Commission states that PJM's Operating Agreement requires that each PJM Board-approved regional transmission expansion plan, including the project costs and the identification of parties to which costs are allocated, be filed with the Commission for approval.[238] Illinois Commission states that it is concerned by the lack of Commission review, given that Midwest ISO's transmission expansion plan imposes enormous costs on electricity customers in the Midwest ISO footprint which will likely increase dramatically if the MVP filing is approved.[239]

188. IPL states that the Commission should require Midwest ISO to add a requirement, similar to provisions in SPP's cost allocation proposal, to protect against disproportionate impacts or unintended consequences.[240] Specifically, IPL states that Midwest ISO should include certain provisions that SPP included in its cost allocation methodology to: 1) require review of its cost allocation methodology and allocation factors at least every three years; 2) authorize the Regional State Committee to recommend any adjustments to the cost allocation if a review shows an imbalanced cost allocation to one or more zones and require that the analytical methods used in the review be defined; and 3) enable member companies that believe they have been allocated an imbalanced portion of costs to seek relief from the Markets Operating and Policy Committee. IPL states that in approving these changes and certain clarifications to SPP's cost allocation provisions, the Commission specifically noted that SPP's "unintended consequences provisions provide a reasonable mechanism for adversely affected parties to raise their concerns through the stakeholder process and for unintended outcomes to be amended."[241] IPL states that the Commission has similarly required Midwest ISO to review and report on how past cost

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[238] *Id.* at 42 (citing Amended and Restated Operating Agreement of PJM Interconnection, LLC, Schedule 6, section 1.6, Substitute Fifth Revised Sheet No. 186). Illinois Commission states that PJM's expansion plan filings have provided a useful forum for interested stakeholders to raise particular issues and concerns with particular projects and particular cost allocations. For example, Illinois Commission states that errors in PJM's cost allocations have been discovered through these filings and the Commission forum provided an opportunity whereby these errors could be adjudicated by the Commission and efficiently corrected by the RTO, thereby obviating the need for litigation.

[239] *Id.* at 40.

[240] IPL Comments at 30.

[241] *Id.* (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 45-48; *see also Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042, at P 95 (2010) (finding SPP's revised unintended consequences provisions to be just and reasonable)).

allocation methods are functioning to determine whether future changes would be necessary.[242]

189. Filing Parties state that Midwest ISO is willing to submit annual reports summarizing the results of the implementation of the proposed Tariff revisions. Filing Parties argue that if a high level of detail will be required, the progress reports should be spread out over a broader time period, such as the 3-year period used by SPP.[243] Filing Parties remind parties that Attachment FF already provides that: "The Transmission Provider shall provide a copy of the MTEP to all applicable federal and state regulatory authorities."[244] Filing Parties also state that Attachment FF provides, in pertinent part, that: "The Transmission Provider shall publish annually, and distribute to all Members and all appropriate state regulatory authorities, a five-to-ten year planning report of forecasted transmission requirements. Annual reports and planning reports shall be available to the general public upon request."[245]

5. <u>Commission Determination</u>

190. Changing operational circumstances in the Midwest ISO region, including continually evolving demands placed on the transmission grid, and corresponding changes to its operation, have prompted a transition from relatively localized transmission system planning to regional planning. Regional planning also addresses new federal and state policy initiatives, such as the increasing adoption of renewable portfolio standards,[246] other state policies that promote increased reliance on renewable energy resources, and a focus by Congress and the Commission on promoting reliability and economically efficient transmission infrastructure development.[247] Collectively,

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[242] *Id.* at 30-31.

[243] Filing Parties October 18, 2010 Answer at 89.

[244] *Id.* (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, Sheet No. 3484).

[245] *Id.* at 89, n.273 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, Sheet No. 3486).

[246] Some 30 states, plus the District of Columbia, have adopted renewable portfolio standards. Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 30.

[247] *See generally* 16 U.S.C. §§ 824o, 824s (2006) (regarding the siting of interstate transmission facilities and transmission infrastructure investment, respectively); Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 19-22.

these changes result in a growing need for new transmission and appropriate cost allocation for such transmission.

191. In Order No. 890, among other reforms intended to clarify and expand the obligations of transmission providers to ensure that transmission service is provided on a not unduly discriminatory basis, the Commission directed each transmission provider to develop a transmission planning process that satisfies nine principles. In adopting "Cost Allocation for New Projects" as one of the nine transmission planning principles, the Commission recognized that knowing how the costs of new transmission facilities would be allocated is critical to the development of new infrastructure, because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.[248] The Commission did not impose a particular cost allocation method, but provided an overall policy framework to permit public utility transmission providers, customers, and other stakeholders to determine methods appropriate for their particular regions that are consistent with the cost causation principle. The Commission explained that up-front identification of how the cost of a facility will be allocated will allow transmission providers, customers, and potential investors to decide, on an informed basis, whether or not to build that facility.[249] As noted above, the Commission recently determined in a series of orders that Midwest ISO's transmission planning process complies with the policy framework of Order No. 890.

192. The Commission continues to seek improvements to cost allocation for new transmission projects. The recent Transmission NOPR proposed, among other things, to establish a closer link between transmission planning processes and cost allocation, and to require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.[250] While compliance

[248] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

[249] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 251. The Commission also stated that neither adoption of a cost allocation method nor identification of an upgrade (whether driven by reliability or economics) in a transmission plan triggers an obligation to build. *Id*.

[250] Specifically: 1) the cost allocation for new (regional or interregional) transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; 2) those that receive no benefit from (regional or interregional) transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities; 3) if a benefit-to-cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional

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with the Transmission NOPR is not at issue here – the Transmission NOPR is a regulatory proposal that was subject to a notice-and-comment procedure under the Administrative Procedure Act, and that has not been finalized – the Commission remains mindful of its goals in evaluating Filing Parties' proposal.

193. Filing Parties' proposal presents the Commission with a functional approach to transmission planning – a package of processes that is intended to enable the development of transmission facilities that will increase the reliable and economic improvement of the transmission system, and support policy initiatives that drive transmission planning processes. Evaluation of MVPs will become a component of the Midwest ISO transmission planning process that the Commission has already approved. Like SPP's highway/byway cost allocation, the proposal fits within the Commission's transmission planning policy framework, but it is "adjunct to a regional transmission planning approach,"[251] and is designed to meet specific regional needs.[252]

194. We find that the proposal provides a package of transmission planning revisions that is just and reasonable, and we will accept Filing Parties' proposal. We expect the

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transmission plan for the purpose of cost allocation (or to qualify for interregional cost allocation), it must not be so high that facilities with significant positive net benefits are excluded from cost allocation; 4) The allocation method for the cost of an intraregional (or interregional) facility must allocate costs solely within that transmission planning region unless another entity outside that region or another transmission planning region voluntarily agrees to assume a portion of those costs; 5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a (regional or interregional) transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility; and 6) a transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan (or interregional facilities), such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 164, 174.

[251] SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 22.

[252] *Id.* P 21-22 ("SPP states that a region-wide approach focuses on the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities to reduce congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy efficiency technologies, and reduced carbon dioxide emissions.").

functional approach to MVP selection to allow Midwest ISO and its members to achieve a number of goals at one time. First, it allows Midwest ISO and stakeholders to identify transmission projects that will have positive benefits for the grid, and that may also satisfy legal and public policy goals in addition to providing just and reasonable pricing on a non-discriminatory basis. Second, the four-part process provides for thorough, transparent consideration of which transmission projects should receive regional cost allocation. Third, the process allows Midwest ISO flexibility to move forward MVPs in appropriate numbers, at appropriate times, in order to maximize regional benefits and to ensure that the costs of each portfolio are widely and fairly distributed. Finally, we find that the integrated process takes another step toward achieving the goal of facilitating efficient regional transmission planning.

195. The Commission and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the "cost causation" principle. According to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[253] The Seventh Circuit recently elaborated on that principle, stating:

> All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have "caused" a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.[254]

The cost causation principle thus requires the Commission to ensure that the costs allocated to a beneficiary under a cost allocation method are at least roughly commensurate with the benefits that are expected to accrue to that entity.[255]

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[253] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (*K N Energy*).

[254] *Illinois Commerce Commission*, 576 F.3d at 476 (citing *K N Energy*, 968 F.2d at 1300; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000) (*Transmission Access Policy Study Group*); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners*, 373 F.3d at 1368; *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Sithe*, 285 F.3d at 4-5).

[255] *Id.* at 476-77 (citing *Midwest ISO Transmission Owners*, 373 F.3d at 1369; *Sithe*, 285 F.3d at 5). The Seventh Circuit further stated: "For that matter, [the

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196. The Commission has recognized in earlier cost allocation orders the integration and interdependence of the utilities in Midwest ISO's integrated grid. For example, the Commission has permitted Midwest ISO to apply administrative charges, and charges associated with operating its energy markets, to transactions under grandfathered transmission service agreements that otherwise do not participate in the Midwest ISO energy markets.[256] The Commission found – and the D.C. Circuit agreed – that "all users of the grid operated by the Midwest ISO will benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability of the transmission system."[257] It is therefore appropriate for all users of the grid to share in the costs of programs and activities that benefit the grid as a whole.

197. A fair assessment of costs requires not only identification of entities to which costs should be allocated, but also consideration of those entities that benefit as a result of those costs. We review proposed assessments with the Supreme Court's admonition in mind that "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[258] As the Seventh Circuit recently clarified, the Commission "does not have to calculate benefits to the last penny, or for

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Commission] can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. But it cannot use the presumption to avoid the duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'" *Id*. at 477 (citing *Western Massachusetts*, 165 F.3d at 927; *Midwest ISO Transmission Owners*, 373 F.3d at 1368).

[256] *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033 (2001) (applying charges for scheduling, system control and dispatch under Schedule 1 of the Tariff, and for Midwest ISO administrative costs under Schedule 10 of the Tariff), *reh'g denied*, 98 FERC ¶ 61,141 (2002), *aff'd sub nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004) (applying charges for administrative costs associated with energy markets under Schedule 17 of the Tariff), *order on reh'g*, 111 FERC ¶ 61,042 (2005), *aff'd sub nom. Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007).

[257] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, (D.C. Cir. 2004)

[258] Filing Parties July 15, 2010 Filing, Transmittal Letter at 13 (citing *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, *reh'g denied*, 325 U.S. 891 (1945) (*Colorado Interstate Gas*)).

that matter to the last million or ten million or perhaps hundred million dollars;" it merely must demonstrate that "it has an articulable and plausible reason" to believe that the benefits are at least roughly commensurate with costs.[259]

198. The Commission has previously recognized circumstances that warranted changes in the manner by which public utilities recover transmission costs. In the early 1990s, the Commission identified "dramatic changes which the electric industry has faced, and will face in the near term," such as "increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems," as well as the initial filing of open access transmission tariffs.[260] To account for those developments and the industry's changing needs, the Commission issued a policy statement that increased flexibility with respect to transmission pricing.[261]

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[259] *Illinois Commerce Commission*, 576 F.3d at 477. The court went on to say that the Commission:

> is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members…. We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. If it cannot quantify the benefits to the Midwestern utilities from the new 500 kV lines in the East … but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis.

Id.

[260] *See Notice of Technical Conference and Request for Comments in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, 58 Fed. Reg. 36,400, 36,401 (1993).

[261] *Policy Statement in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, 69 FERC ¶ 61,086 (1994).

199. In Order No. 890, the Commission stated that, when considering a dispute over cost allocation, it would exercise its judgment by weighing several factors. First, the Commission stated that it would consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them. Second, the Commission stated that it would consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, the Commission stated that it would consider whether the proposal is generally supported by state authorities and participants across the region.[262] Therefore, the Commission considers first whether Midwest ISO's MVP Methodology fairly assigns costs among Midwest ISO members.

200. We find that the Filing Parties have demonstrated that the MVP proposal is a framework that will result in the allocation of the costs of transmission projects on a basis that is "roughly commensurate" with the benefits of those projects and that the proposal is otherwise just and reasonable. We find that each of the four principal aspects of the proposal is persuasive as we reach this conclusion.

201. First, as further described below, each project must meet one of the three criteria for inclusion as an MVP. This initial screen will ensure that each project can benefit the Midwest ISO region.

202. Second, the portfolio approach to selection of MVPs for cost allocation helps to ensure that the benefits, as well as the costs, of the projects are spread broadly through the Midwest ISO region. The Commission recognizes that it can be difficult, and controversial, to identify which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries in an integrated transmission grid. Experts recognize that "an MVP will always provide some enhancement to system robustness and will thereby make the system more resilient to unforeseen contingencies threatening the reliable delivery of service to customers."[263] The system is planned to maintain reliability with the loss of large transmission lines or the unplanned outages of generation resources. However, the ability of the system to operate reliably under these conditions cannot necessarily be quantified in dollars in the same manner as economic benefits. The inability of a model to economically quantify the reliability benefit of any particular transmission line does

[262] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

[263] Filing Parties July 15, 2008 Filing, Curran Test. at 27.

not mean that there is no value to reliability. Studies show that customers value dependable electricity and that outages cause real economic losses.[264]

203. Third, the MTEP stakeholder process will provide a venue for the cost-benefit calculation of individual projects. Stakeholders will have an opportunity in the MTEP to review and to challenge studies that quantify the costs and benefits of each individual MVP, and therefore of the regional cost allocation. If there is a lack of unity as to these benefits and costs, the dispute resolution procedures of the Tariff will be available to stakeholders. Stakeholders may also seek alternative dispute resolution through the Commission, or file a section 206 complaint, if the stakeholder process does not satisfy their concerns.

204. Finally, we note that the MVP proposal is generally supported by state authorities and participants across the Midwest ISO region. The stakeholder process for the MVP proposal was both long in duration and inclusive of interested parties. As noted by the OMS, a majority of its members have generally agreed to support its comments supporting the proposal.[265] Additionally, we note that the MVP proposal was approved by the Advisory Committee, which is comprised of nine stakeholder sectors.

205. The Filing Parties' proposal will require "judgment on a myriad of facts," through these various processes, which will be open to Midwest ISO stakeholders, regulators, and other interested parties. We agree that individual review of proposed MVPs, combined with the portfolio approach to selecting projects, allows Midwest ISO to maximize the regional benefits attainable from any year's MTEP, and to ensure that those regional benefits are broadly spread across its footprint.

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[264] *E.g.*, Peter Fox-Penner, *A Year Later, Lessons From the Blackout*, N.Y. Times, Aug. 15, 2004 at 14WC. *See also* Primen, *The Cost of Power Disturbances to Industrial & Digital Economy Companies* (June 29, 2001), at D-1, *available at* http://www.on-power.com/pdf/EPRICostOfPowerProblems.pdf (visited Dec. 14, 2010).

[265] OMS Comments at 14. The members that generally support the MVP proposal are Indiana Commission, Iowa Board, Michigan Commission, Minnesota Commission, Missouri Commission, Montana Commission, North Dakota Commission, South Dakota Commission, and Wisconsin Commission. Illinois Commission, Public Utilities Commission of Ohio, and Pennsylvania Public Utility Commission abstained from the vote on these comments. Manitoba Public Utilities Board did not participate in OMS' pleading. Only Kentucky Public Service Commission explicitly does not support OMS' comments regarding the MVP proposal.

206. Having found the MVP proposal just and reasonable, we need not address the merits of an alternative proposal to allocate costs to generator interconnection customers, as discussed below.[266] However, we agree with parties that the Filing Parties should file annual reports to the Commission, as described below.

a. Criteria

207. As described above, in order to qualify as an MVP, a candidate project must meet at least one of three criteria. Any project that is approved as an MVP must be shown to bring about an increase in reliability or economic efficiency, and Midwest ISO expects that a substantial number of projects approved as MVPs will present multiple types of regional benefits.[267] Under Criterion 1, an MVP must support a qualifying policy initiative and "must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade."[268] Criterion 2 requires that an MVP provide multiple types of economic benefits across multiple pricing zones, and Criterion 3 requires that an MVP address one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based transmission issue that provides economic value across multiple pricing zones. Midwest ISO and stakeholders will review each candidate MVP on an individual basis in order to assess its benefits.

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[266] *See Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (finding that, under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one"); *cf. City of Bethany v. FERC*, 727 F.2d 1131, 1136, 234 U.S. App. D.C. 32 (D.C. Cir. 1984) (when determining whether a proposed rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). *See also Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009) (finding that, because the Commission found the ISO's proposal to be just and reasonable, it need not assess the justness and reasonableness of an alternative proposal); *Louisville Gas & Electric Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (March 17, 2006 Order) (finding that "the just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard. Rather, a range of alternative approaches often may be just and reasonable").

[267] Filing Parties July 15, 2010 Filing, Curran Test. at 7.

[268] *Id.* at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet Nos. 3451A-B.

208. We find that Criterion 1 will ensure regional benefits by more efficiently integrating new generation resources to meet documented energy policy mandates or laws throughout the region. Criterion 1 contains a two-prong requirement: An MVP must support documented energy policy goals, as noted above, and it "must be shown to enable the transmission system to delivery such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade."[269] Pursuant to this criterion, any candidate MVP must be subject to an open, transparent analysis in the MTEP of the costs and regional benefits that it will provide, even if the MVP is proposed primarily for reasons of public policy.

209. In response to commenters' concerns about the specific requirements of Criterion 1, we find that it is neither too broad nor too vague. We are sensitive to Filing Parties' need to ensure that transmission expansion projects undertaken to satisfy a diverse array of documented energy policy mandates or laws or regulatory requirements from various jurisdictions are included under Criterion 1. In response to parties' request that the Commission clarify what constitutes compliance with documented energy policy mandates or laws or regulatory requirements, we find that the question should be addressed by Midwest ISO and its stakeholders, which include those jurisdictions. Thus, we reject requests that Criterion 1 be further clarified.

210. Parties who claim that Criterion 1 is overly broad so as to result in overbuilding or inefficient building do not explain how Midwest ISO's open and transparent planning process would fail to give voice to a party or parties who expressed such concerns about a transmission project that is believed not to merit MVP designation. We find that Filing Parties have presented persuasive evidence that MVPs qualifying under Criterion 1 will be driven by substantial need for transmission upgrades.[270] The MVP methodology will support the development of new transmission facilities that among other things will support documented energy policy mandates or laws that presently exist in 11 out of 13 states because the MVP proposal resolves a key issue that is preventing significant new transmission from being built – who pays.

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[269] Filing Parties October 18, 2010 Answer at 15.

[270] *See, e.g.*, Midwest ISO, *Regional Generation Outlet Study* (Dec. 2009), *available at* http://www.midwestiso.org/publish/Document/75871b_126e10582e3_-7c490a48324a/RGOS_I_Executive_Summary_Report_FINAL.pdf?action=download&_property=Attachment. Witness Moeller explains that the Regional Generation Outlet Study is an example of a transmission study that takes a longer-range regional view to develop longer-term solutions that can begin to be implemented in the present. Filing Parties July 15, 2010 Filing, Moeller Test. at 10.

211. AMP voices concern that Criterion 1 is silent on application to municipal laws and that, were a municipality's mandates to be excluded, imposing MVP costs on that municipality's load would be unduly discriminatory. We are not clear if this is a present concern, that is, if AMP or another municipal entity has developed a mandate that is apart from the mandate of its state. We believe that this issue should be addressed in Midwest ISO's stakeholder process.

212. Finally, we disagree with PSEG Companies' assertion that Filing Parties' are attempting to make determinations regarding how states or load-serving entities should meet federal or state public policy requirements. PSEG Companies appear to suggest that Midwest ISO and the other Filing Parties will be putting themselves in the position of state commissions. However, we expect that state regulators and other stakeholders will be actively involved in identification of MVPs, and that, as a transmission provider, Midwest ISO will be receiving input from, and acting in conjunction with, the state commissions. We recognize the importance of involving state commissions, as well as regional state committees such as OMS, and all other stakeholders, in making decisions about projects being developed and built in the Midwest ISO region and elsewhere. This is particularly so in light of the diversity among the Midwest ISO sub-regions and its market participants. We are confident that Midwest ISO's existing transmission planning process, which Midwest ISO and its stakeholders developed as part of the Order No. 890 compliance process, will continue to allow all stakeholders, including state regulators, to participate in the development and identification of transmission projects, including candidates for MVP cost allocation.[271]

[271] May 2008 Planning Order, 123 FERC ¶ 61,164. Section I.A.2 of Attachment FF of the Midwest ISO Tariff includes procedures for stakeholder input into the planning process. Stakeholder participation is currently accomplished through the Planning Advisory Committee, which is responsible for addressing planning policy issues of importance to stakeholders. The Planning Advisory Committee reports to Midwest ISO's Advisory Committee. We also remind commenters that section I.A.14 of Attachment FF provides dispute resolution procedures that specifically address how Midwest ISO will handle disputes that arise in the development of an MTEP or the cost allocation associated with projects.

Given the above-procedures for stakeholder input, we disagree with Illinois Commission that the out-of-cycle review process allows transmission owners to get project approval by circumventing the MTEP process and stakeholder review. The out-of-cycle review process is still subject to all other requirements contained within Attachment FF (e.g., openness, transparency, and information sharing).

213. We find that Criterion 2 appropriately ensures that the projects that qualify for MVP status under its conditions generally will have broad regional benefits such that applying regional cost sharing is just and reasonable. From its definition, projects that qualify for MVP status under Criteria 2 must demonstrate multiple types of economic benefits in multiple pricing zones and that the benefits of such projects exceed the associated costs of such projects. As such, Criterion 2 ensures that the projects qualifying for MVP status have regional benefits, and protects against projects with only localized benefits qualifying from receiving broad regionally cost sharing. We also note that Criterion 2 provides a rigorous qualification standard because not only do the economic benefits have to be demonstrated to be widespread, but to qualify for MVP status a project would need to have multiple types of economic benefits. A project demonstrating only production cost savings in multiple zones would not be sufficient, but the project would have to additionally demonstrate other economic benefits such as capacity losses savings or reductions in the overall planning reserve margins in order to qualify for regional cost sharing.

214. As to those parties that argue that Market Efficiency Projects are subject to a different benefit-to-cost ratio test than MVPs, we find that the arguments made are not relevant here. In this proceeding, the Commission is only making a determination as to whether the 1.0 benefit-to-cost ratio for MVPs under Criterion 2 is just and reasonable. While we note that commenters have submitted anecdotal evidence to further their argument that the benefit-to-cost ratio test for Market Efficiency Projects may be too stringent, we also note that Midwest ISO has committed to a new RECB stakeholder process to evaluate other cost allocation issues in the near future. Filing Parties state that the benefit-to-cost ratio for Market Efficiency Projects would be part of that stakeholder process.[272] In any case, because MVPs are projects that provide regional benefits, we find that a benefit-to-cost ratio of 1.0 is just and reasonable because it ensures that the multiple economic benefits to all users is at least equal to the costs allocated to all users over the 20 years of service that are evaluated. Moreover, we also agree with Filing Parties that benefits are expected to accrue well after 20 years of service.[273]

215. We find that Criterion 3 will ensure that the projects that qualify for MVP status under its conditions generally will have broad regional benefits such that applying regional cost sharing is just and reasonable. Criterion 3 requires that qualifying projects address at least one transmission issue associated with a projected violation of a NERC or Regional Entity Reliability Standard and at least one economic based transmission issue

[272] Filing Parties July 15, 2010 Filing, Curran Test. at 16-17.

[273] We will address concerns that Criteria 2 and 3 subsume RECB categories of network upgrades in a separate section of this order.

that provides economic value across multiple pricing zones. Criterion 3 also will ensure the total financially quantifiable benefits are in excess of the total project costs. Similar to projects qualifying for MVP status under Criterion 2, projects that qualify under Criterion 3 generally would be providing widespread regional benefits. Applying Criterion 3 protects against Midwest ISO granting regional cost sharing to projects that solve reliability issues but only provide local economic benefits. Criterion 3 applies a tough standard to ensure qualifying projects are in fact regionally beneficial as such projects have to show that they are both beneficial to the region in addressing a projected reliability violation and in providing regional economic benefits. We also note that the cost threshold for the MVP is $20 million which will help ensure that that projects qualifying for MVP status under Criterion 3 are regional in nature. As such, we believe Criterion 3 applies appropriate and rigorous standards to ensure MVPs that have more than one purpose (i.e. they provide both economic and reliability value) also have regional benefits such that regional cost sharing is appropriate. We reject ATC's request for clarification that a project being considered under Criterion 3 should only have its benefits compared to the costs of the "economic" portion of the project. Granting the clarification ATC seeks would subvert the premise that total benefits must be greater than the total costs for a project to receive regional cost sharing and would have the effect of lowering the *de facto* benefit-to-cost ratio test to something less than 1:1.

216. In sum, the provisions of Criteria 1, 2, and 3 persuade us that each candidate MVP will provide the Midwest ISO region with an identifiable regional benefit, and in many cases multiple such benefits. We therefore reject, as unnecessary, suggestions to modify the proposal to remove any of the criteria or to require that MVPs qualify for cost-sharing by meeting more than one of the criteria. We find that the criteria, read individually and together, require Midwest ISO to analyze each candidate MVP in MTEP to evaluate its individual costs and benefits.

217. We also accept Filing Parties' proposal to allow projects rated at 100 kV or higher (including any lower-voltage underbuild) to receive regional cost sharing under the MVP methodology. In the RECB II proceedings, the Commission accepted the 345 kV voltage threshold for projects to receive 20-percent regional cost sharing because Midwest ISO demonstrated that for a utility to "self-serve" its load reliably, such service would have a 20-percent reliance on the overall transmission systems. That is, even though these projects were generally intended for local generation to serve local load, there was still a 20-percent to 30-percent regional usage component.[274] Here, even though we are not accepting a bright-line 345 kV voltage threshold for a project to qualify for MVP cost allocation, the 100 kV voltage criterion that we are accepting, together with the three

[274] *See* RECB II Order, 118 FERC ¶ 61,209 at P 47.

functional criteria and the $20 million minimum project cost requirement associated with MVP facilities, lends assurance that the facility's benefits will be of sufficient size and scope to be material to the Midwest ISO region as a whole.

218. In particular, we agree with Filing Parties that the "backbone" transmission system of the Midwest ISO footprint varies and, in some areas, the backbone is 161 kV. Thus, a change of the voltage threshold from 100 kV to 230 kV or above would undermine any regional development in those areas and could produce unduly discriminatory results. Further, as Filing Parties point out, the 100 kV threshold represents the minimum size transmission facility over which Midwest ISO generally exercises functional control.

219. For those parties protesting the 100 kV voltage threshold by generally stating that 100 kV facilities perform a more local function, such an argument ignores the specific criteria established by Filing Parties. Filing Parties' proposal requires that qualifying facilities provide regional benefits as described by one of three MVP criteria. The voltage cutoff in the MVP proposal serves to ensure the materiality of the project; however, it does not qualify the project. A project that meets the voltage cutoff must still be evaluated on the basis of whether it meets the criteria proposed by Filing Parties. Therefore, we do not accept the suggestion that we create a rebuttable presumption that network upgrades required for generator interconnection rated at 345 kV or higher automatically qualify as MVP.

220. As to the suggestion that an underbuild facility should not receive MVP treatment, we find that the costs of underbuilds that are not required but for the MVP (i.e., that are required solely to address reliability impacts of an MVP) should not be assigned solely to the local load as such a result is counter to cost causation principles, as the MVP would cause the need for these improvements.[275] We find that it is appropriate to allocate the costs of the underbuild associated with a MVP because it is these underbuild facilities that will ensure reliable system operation in case of an outage of the MVP facility. For example, if a MVP transmission line trips off-line due to a fault, it is the remaining transmission system and the underbuild associated with that MVP transmission line that will prevent a cascading failure of the transmission system.

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[275] We will also reject MPPA's request to limit underbuild costs to 50 percent of the combined project cost. We find that it is just and reasonable to assign the costs of underbuild facilities to the same entities that benefit from the associated higher voltage facilities. We also disagree with the suggestion that the definition of underbuild unreasonably includes upgrades determined by Midwest ISO's contingency analysis to existing resources. We find that it is appropriate for Midwest ISO to plan its system to accommodate both existing and planned resources, and allocate costs accordingly.

b. Portfolio Approach

221. According to Filing Parties, projects designated as MVPs will "be reviewed holistically on a 'portfolio' basis, taking into account the synergistic effects of individual qualifying MVPs, and approving the set of MVPs that collectively comprise an optimized regional solution."[276] Filing Parties go on to explain that:

> MVPs are multi-faceted projects that collectively comprise an optimal regional solution. Those commenters who are focused on one specific project overlook the collective regional benefits of multiple MVPs that are evaluated as a portfolio or package. This package of projects is designed (and evaluated) to provide a regional solution that globally benefits all users of the Midwest ISO transmission system. It is illogical to isolate one facet of this packaged solution.[277]

As described, the portfolio approach will help Midwest ISO to prioritize its transmission expansion projects in such a way as to ensure global benefits from the projects afforded regional cost sharing and maximize the number of system users who will share in those benefits. Midwest ISO's ability to move projects in a portfolio forward with an eye to the benefits for the entire region will also assure that its analysis takes into proper consideration the need to match costs with benefits.As the Commission stated with regard to SPP, "[w]e recognize that every utility will have different transmission needs depending on its unique load profile and resource mix. However . . . we find that the SPP zones are similarly situated in the context of transmission planning and cost allocation because all of the zones consist of RTO participants, users, and beneficiaries of the same regionally-integrated [extra-high voltage] transmission network. As such, they accrue certain benefits common across all SPP zones."[278] We find that this applies to the Midwest ISO region as well.

222. We find that the portfolio approach resolves the concerns of the protestors who propose disparate treatment for certain portions of Midwest ISO. Protestors' arguments do not acknowledge the integrated nature of the system or the potential for upgrades in one area to improve the entire system. The D.C. Circuit has found that the integrated nature of the grid justifies spreading costs broadly:

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[276] Filing Parties October 18, 2010 Answer at 15.

[277] *Id.*

[278] SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 82.

> [E]ven if they are not in some sense *using* the ISO, the MISO Owners still benefit from *having* an ISO. In this sense, [Midwest ISO] is somewhat like the federal court system. It costs a considerable amount to set up and maintain a court system, and these costs – the costs of *having* a court system – are borne by the taxpayers, even though the vast majority of them will have no contact with that system (will not *use* that system) in a given year. . . . The MISO Owners' position is tantamount to saying that if they are not a litigant, they should not be made to pay for any of the costs of *having* a court system. Since the MISO Owners do, in fact, draw benefits from being part of the [Midwest ISO] regional transmission system, [the Commission] correctly determined that they should share the cost of *having* an ISO.[279]

We note that we are accepting a functional method of determining which projects should qualify as MVPs, and we are not determining whether any projects meet those qualifications. Some protestors point specifically to the Michigan Thumb Project as an MVP candidate that will not provide regional benefits.[280] Both load inside of and outside of Michigan will receive, and continue to receive, broad regional benefits from the integrated Midwest ISO transmission system and the broader Midwest ISO/PJM bulk power system and its regional pricing structure. We are not convinced by certain protestors' claims that they expect to shoulder an unfair amount of the costs associated with MVPs based on the costs of a single specific project, such as the Michigan Thumb Project. Furthermore, we note that the Commission eliminated through-and-out rates between Midwest ISO and PJM in part to address connectivity issues and that this order maintains the elimination of those through-and-out rates. The change in the utilities' RTO memberships will not affect the physical connections between their systems or the rates paid to transmit across them.

223. We are concerned, however, that Midwest ISO has not stated its portfolio approach in the Tariff. We therefore require Midwest ISO to submit, within 60 days of the date of this order, a compliance filing to revise the Tariff to state that MVPs will be reviewed on a portfolio basis.

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[279] *Midwest ISO Transmission Owners*, 373 F.3d at 1371.

[280] ABATE points to the physical interconnections between utilities in Michigan and the rest of Midwest ISO to show that, once FirstEnergy leaves Midwest ISO and joins PJM in 2011, the only remaining interconnections between Michigan and Midwest ISO will be two 138 kV lines in the Upper Peninsula of Michigan and one 138 kV between METC and NIPSCO.

c. Stakeholder Process

224. The Commission requires RTOs and ISOs to maintain a coordinated, open and transparent transmission planning process on both a regional and a local level.[281] Transmission-owning members of the RTO or ISO must participate, and "[i]n order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process."[282] The Midwest ISO's transmission planning process, as we have noted above, already has been found to be consistent with Order No. 890; the proposal here will merely add another dimension to the planning process.

225. Midwest ISO makes clear that the process of identifying MVPs will be open and transparent, in accordance with Order No. 890:

> The Commission-approved planning process offers multiple opportunities for all stakeholders, from transmission owners to state regulators to generators, to provide input and feedback on all aspects of a study from assumptions to results. MVPs will move through the same Commission approved planning process. Furthermore, it is anticipated that scrutiny by stakeholders will be increased given the regional size, scope, and cost sharing of MVPs. . . . Monthly stakeholder meetings are planned for the duration of the study to communicate the results of detailed engineering and economic analyses, and obtain feedback from stakeholders, as appropriate.[283]

226. Based on Filing Parties representations, we find that the stakeholder process will permit stakeholders to provide their input on the designation of projects as MVPs, including the projects' costs, benefits, and compliance with the inclusion criteria. We note again that if there is a lack of unity as to these benefits and costs, the dispute resolution procedures of the Tariff will be available to stakeholders. Stakeholders may also seek alternative dispute resolution through the Commission, or file a section 206 complaint, if the stakeholder process does not satisfy their concerns.

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[281] Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 435.

[282] *Id.* P 440.

[283] Filing Parties October 18, 2010 Answer at 35.

d. <u>Studies</u>

227. Cost allocation, as we have explained above, requires "judgment on a myriad of facts,"[284] and the Commission must have "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with the costs in question.[285] The studies that Midwest ISO uses to analyze candidate MVPs will provide such a basis for cost allocation.

228. As described above, the MVP proposal is intended to bring to the Midwest ISO region projects that will have regional benefits. To support this proposition, Filing Parties submit a list of MVP starter projects, and states that it expects those projects to win approval for regional cost sharing in MTEP. Its witnesses describe an array of benefits from these projects.

229. We find that Filing Parties have submitted persuasive evidence that supports a broad approach to cost allocation for projects that qualify as MVPs. Filing Parties performed an analysis of the MVP starter projects and estimate that these projects will deliver between $582 million and $798 million in <u>annual</u> economic benefits starting in 2015 from expected production cost savings, reductions in transmission losses, and a reduction in the region's reserve margins.[286] Filing Parties divide these estimated annual savings into the following categories:

- Between $297 million and $423 million in annual adjusted production cost savings, spread almost evenly across all Midwest ISO Planning Regions;

- Between $68 million and $104 million in annual transmission system loss savings when the starter projects are put into service;[287] and

- Between $217 million and $271 million in annual reductions of the region's reserve margin is realized due to load diversity.[288]

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[284] *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, *reh'g denied*, 325 U.S. 891 (1945).

[285] *Illinois Commerce Commission*, 576 F.3d at 477.

[286] Filing Parties July 15, 2010 Filing, Curran Test. at 26.

[287] This estimate is associated with an annual reduction in transmission losses of approximately 1,500,000 to 2,000,000 MWh. *Id.*, Curran Test. at 24.

230. Filing Parties note that higher production cost savings and savings in deferred capacity investment could add billions of dollars to this indicative estimate of the MVP starter projects in the long run.[289] For example, Filing Parties estimate that the annual production cost savings, listed in the first bullet above, increases to between $400 million to $1.3 billion by 2025.

231. Filing Parties state that related benefits quantified from the MVP starter projects include annual potential load cost savings ranging from $14 million to $984 million in 2015 and negative $19 million to $2 billion in 2025.[290]

232. Filing Parties indicate that further benefits may be realized, although these further benefits were not quantified from the MVP starter projects. They state that even a relatively small reduction of 0.5 percent in reserve requirements would result in a deferral of about 500 MW of capacity investment, saving approximately $500 million.[291] Filing Parties also indicate that a transmission system that is more resilient to contingencies, and thus more reliable, should reduce wind facility curtailments by approximately 25 percent in the east region.[292]

233. By contrast, Curran states that the estimated annual revenue requirement for the starter projects is $675 million.[293]

234. Some parties find fault with the studies performed by Filing Parties. The debate centers on the inputs and assumptions used in the various studies. Several protestors raise objections to those inputs. However, we find that Filing Parties have provided persuasive evidence that their choice of inputs, although questioned by protestors, is reasonable. Filing Parties explain that peak load forecasts used in the transmission studies were provided by load-serving entities for use in resources adequacy studies. These estimates were not calculated by Filing Parties. Filing Parties also defend their estimate of the cost of new entry, stating that it is roughly between the cost of a new combustion turbine and combined cycle unit. Further, they state that the estimate is

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[288] *Id.*, Curran Test. at 26.

[289] *Id.*

[290] *Id.*, Lawhorn Test. at 13-14.

[291] *Id.*, Curran Test. at 25.

[292] *Id.*, Transmittal Letter at 16-17, Lawhorn Test. at 12-14.

[293] *Id.*, Curran Test. at 26.

conservative, given that the current interconnection queue includes coal and nuclear units with much higher costs of entry.[294] Indeed, Iowa Advocate makes an argument so broad that would call into question the ability to make forecasts. As to Iowa Advocate's specific argument that there is no guarantee that states in the eastern portion of Midwest ISO will buy renewable power from the western portion, we note that 11 of the 13 Midwest ISO states themselves have renewable portfolio standards of one sort or another. Thus, it is reasonable to conclude that there will be purchases of renewable energy by many states from sources in other areas of Midwest ISO, including from west to east.

235. MICH-CARE states that it is likely that residential customers who live far away from an MVP would receive little or no benefit, yet they would be required to help pay for the project under the Midwest ISO proposal. As MICH-CARE explains, this is especially acute for Michigan because of the state's relative isolation from the bulk of the Midwest ISO system.[295] Michigan, MPPA states, will represent approximately 20 percent of the load in Midwest ISO and thus under Midwest ISO's proposal to pay approximately 20 percent of the costs of all MVPs. Since Michigan law requires them to rely on in-state renewable resources, MPPA states, it cannot receive such benefits.[296]

236. However, MICH-CARE's arguments would require acceptance of the notion that load in Michigan does not benefit from bordering Midwest ISO transmission facilities. We disagree. Midwest ISO operates its transmission system and its energy and operating reserves markets on a single-system regional basis to reliably and efficiently integrate resources to serve loads throughout its entire footprint. The strong regionally-integrated transmission network that results from Midwest ISO's independent regional planning provides reliability and efficiency benefits to all that are interconnected to it. The fundamental benefit of the MVP facilities supporting regional power flows is the flexibility they provide to deliver energy and operating reserves more efficiently and reliably within and between balancing areas throughout the Midwest ISO footprint. Although such benefits may accrue at different times to different customers with respect to different groups of transmission projects that enter the plan, these benefits will be widely experienced by Midwest ISO members and will accrue over time. Moreover, by ensuring that MVPs will provide regional benefits through application of the MVP criteria and by assembling these same projects into a portfolio of projects that span

[294] Filing Parties October 18, 2010 Answer at 22.

[295] MICH-CARE Comments at 5-6.

[296] MPPA Comments at 8.

Midwest ISO, the MVP methodology will ensure that allocations of costs are roughly commensurate with associated benefits.[297]

237. The fact that protestors would have chosen to use different study methods and assumptions than Midwest ISO does not necessarily render Midwest ISO's analysis unreasonable to demonstrate the benefits derived from the MVP starter projects.

238. Filing Parties also performed a transmission usage study (a mileage-weighted analysis) of the MVP starter projects as well as other projects rated at 345 kV and above which demonstrated that the utilization of these transmission facilities would be approximately 80-percent regional. We find that these results regarding transmission usage provide additional evidence to support the regional benefits of MVPs.

e. Alternative Cost Allocation

239. As noted in the October 23, 2009 Order, the Commission has recognized that location-constrained resources present unique challenges that other resources do not present.[298] The July 9 Applicants in the Docket No. ER09-1431-000 proceeding stated that applying the then-existing Line Outage Distribution Factor methodology to allocate costs of generation interconnection network upgrades imposed disproportionate costs on loads in the pricing zones where new generation locates, when the pricing zone in question has high levels of new generation concentration relative to its load. The July 9 Applicants in that proceeding stated that, absent the Commission accepting their proposal, it is virtually certain that Otter Tail Power Company and Montana-Dakota Utilities Company would file to withdraw from Midwest ISO rather than exposing customers in their respective zones to dramatically increased costs.[299] To address these disproportionate effects, the July 9 Applicants proposed to assign between 90 and 100 percent of the costs of network upgrades that would not be required "but for" the generator interconnection customer to the interconnection customer. The Commission's acceptance was conditioned upon the July 9 Applicants fulfilling their commitment to file superseding Tariff revisions regarding the Phase II cost allocation methodology on or

[297] We find that the concern here relates to cost overruns, and this issue is more appropriately addressed in proceedings seeking to disallow imprudent costs, if such overruns occur as a result of imprudence.

[298] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58 (citing, *e.g.*, *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,061, *reh'g denied*, 120 FERC ¶ 61,244 (2007)). *See also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 543, 548-549.

[299] Midwest ISO July 9, 2009 Filing, Docket No. ER09-1431-000, Transmittal Letter at 2-3.

before July 15, 2010 as just and reasonable and not unduly discriminatory or preferential.[300]

240. Despite several parties' request that the Commission direct Midwest ISO to assign MVP costs to generators, we believe that the MVP proposal strikes a balance by retaining the existing generator reimbursement policy[301] while allowing a means for generators to mitigate those costs by choosing to site their projects closer to MVP facilities and we will reject the calls for assigning a portion of MVP costs to generators. Parties that suggest that the proposal will lead to inefficient siting miss the point that a major goal of this proposal is to incent generators to locate closer to qualified MVP facilities. Generators that nevertheless site in locations electrically distant from MVP facilities will bear cost responsibility for those interconnection costs.[302] For the reasons discussed herein, we find Filing Parties' proposal not to assign MVP costs to generators to be just and reasonable. Having found the MVP proposal just and reasonable, we need not address the merits of an alternative proposal.[303]

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[300] October 23, 2009 Order, 129 FERC ¶ 61,060 at P 49.

[301] As discussed below, we find that the MVP proposal strikes an appropriate balance between generation developers and other interests in Midwest ISO by retaining the existing reimbursement policy of 90-percent participant funding for network upgrades that would not be required "but for" the generation developer while providing a means for generation developers to mitigate those costs by choosing to site near MVPs.

[302] On Alliant's concerns that this pricing signal does not exist in ATC and ITC – where interconnection customers are fully reimbursed for their facilities – we have previously found that reimbursement policies are only one of various factors that would be considered in siting. The other factors include, for instance, the initial outlay required for network upgrades required for interconnection, the proximity to fuel sources, rights of way, any congestion and/or the time required for the necessary network upgrades to be built permitting delivery of the generation. *See* August 7, 2008 Order, 124 FERC ¶ 61,150 at P 19. In any case, Filing Parties are not proposing to change any reimbursement policies.

[303] *See Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (finding that, under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one"); *cf. City of Bethany v. FERC*, 727 F.2d 1131, 1136, 234 U.S. App. D.C. 32 (D.C. Cir. 1984) (when determining whether a proposed rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). *See also Cal. Indep. Sys. Operator Corp.*,

(continued…)

241. In sum, the present proposal not only addresses the challenge of interconnecting location-constrained resources in the western reaches of Midwest ISO, but facilitates investment in qualifying transmission projects throughout Midwest ISO. In addition the proposal addresses multiple reliability and/or economic issues affecting multiple transmission zones

242. We disagree with commenters that Filing Parties' proposal will lead to overinvestment in transmission. The Commission finds that there are sufficient safeguards in place to protect parties against excessive costs. For example, Midwest ISO transmission planning process provides information and opportunity for comment on transmission upgrades and is a transparent process administered by an independent entity charged with ensuring cost-effective planning. Midwest ISO's transmission planning process takes a least-cost approach when selecting the preferred solution, among alternatives, to an identified need. In addition, individual siting decisions and rate approval exercised by the state commissions provide additional protection against excessive costs.

f. Annual Reporting

243. We appreciate commenters' suggestions as to Midwest ISO filing annual informational reports with the Commission regarding the selection of MVPs. Although the recommendations to publish on its website and make annual informational filings with the Commission are reasonable, we agree with Midwest ISO that requiring reports more frequently is unnecessary and time prohibitive. Accordingly, we require Midwest ISO to submit ongoing annual informational reports with the Commission describing the selection of MVP facilities. Midwest ISO should work with its stakeholders to assess the achievements and shortcomings of the MVP selection process after each full planning cycle has been completed and file an informational report with the Commission. We will not preempt the MTEP process by determining in this docket that any of the starter projects is or is not an MVP.[304]

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128 FERC ¶ 61,282, at P 31 (2009) (finding that, because the Commission found the ISO's proposal to be just and reasonable, it need not assess the justness and reasonableness of an alternative proposal); *Louisville Gas & Electric Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (March 17, 2006 Order) (finding that "the just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard. Rather, a range of alternative approaches often may be just and reasonable").

[304] We cannot grant Iberdrola's request for clarification of the Community Wind

(continued…)

244. With regard to Illinois Commission's suggestion that Midwest ISO file the MTEP report annually, pursuant to section 205(c) of the FPA, we find this requirement unnecessary since Midwest ISO is already required to provide the annual MTEP report to all applicable federal and state regulatory authorities on an annual basis pursuant to its Tariff. We find that this requirement, in addition to the informational filings with the Commission we require above, will provide stakeholders, including state regulators, adequate knowledge of and opportunity to challenge the selection of projects and the associated cost allocation. In addition, we encourage state commissions to be actively involved in the Planning Advisory Committee, Planning Subcommittee and Sub-Regional Planning meetings so that they may actively inform Midwest ISO and its other stakeholders of their concerns and make suggestions for the selection of the MVPs and other projects. Similarly, we find it unnecessary to require Midwest ISO to include an "unintended consequences" provision similar to that which is included in the SPP tariff since the process for determining projects eligible for regional cost sharing is different. Under Filing Parties' proposal, stakeholders will be able to review the selected projects and the associated cost allocation as this information is being disseminated through each of the committees, in addition to the required website postings and informational filings.[305]

B. Other Issues Raised Regarding MVP Criteria

245. In addition to the issues discussed above, numerous parties raise issues regarding other elements of the proposal. For instance, in the RECB I and RECB II cost allocation proceedings, Midwest ISO used $5 million as the minimum project cost threshold for a project to be eligible for 20-percent regional cost sharing. In this proceeding, Filing

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decision in this proceeding; such requests must be filed in the docket in which the original order was issued.

[305] IPL believes that the Commission should consider requiring Midwest ISO to implement cost caps similar to those that the Commission adopted by California Independent Transmission System Operator Corp. (CAISO) to mitigate the cost shift associated with transitioning from utility-specific rates to one CAISO grid-wide rate. IPL Comments at 31-32 (citing Opinion No. 478, 109 FERC ¶ 61,301, June 2, 2005 Rehearing Order, 111 FERC ¶ 61,337). At the outset, we note that the Opinion No. 478 at P 74 addressed a cost cap that did not apply to expansion facilities that were developed in conjunction with and with the approval of the ISO to benefit the entire ISO-controlled grid. Nonetheless, we note that the opportunity for stakeholders to review and comment on proposed MVPs also addresses IPL's suggestion that the Commission consider requiring Midwest ISO to implement cost caps similar to those the Commission approved in Order No. 478.

Parties propose to require MVPs to have a minimum project cost of $20 million in order to be eligible for 100-percent regional cost allocation. Numerous parties provide arguments both for and against the proposal.

246. Another issue raised by parties relates to how the MVP proposal will relate to the cost allocation methodologies in the RECB I and RECB II proceedings. More specifically, certain parties are concerned that the MVP cost allocation methodology will subsume or otherwise render moot the cost allocation methodologies for Baseline Reliability Projects and/or Market Efficiency Projects.

247. Finally, many parties argue that, as proposed, the MVP cost allocation methodology improperly precludes network upgrades that arise from a transmission service request from receiving 100-percent regional cost allocation.

1. Comments

a. $20 Million Cost Threshold

248. Edison Mission argues that Filing Parties have not adequately justified the $20 million cost threshold for projects to qualify for MVP cost allocation. Edison Mission states that the Commission should eliminate the $20 million cost threshold, or in the alternative, reduce it to $5 million consistent with the thresholds established for Baseline Reliability Projects and Market Efficiency Projects.[306] E.ON agrees that the capital cost threshold must be lowered to $5 million. Alternatively, E.ON suggests that the Commission order Filing Parties to provide empirical data demonstrating that a $20 million threshold: 1) will not perpetuate cost barriers to new wind generation development; and 2) will not result in unjust and unreasonable rates.[307]

249. On the other hand, OMS, Iowa Board, NIPSCO and OCC submit that the cost threshold for qualifying for MVP cost allocation should be raised from $20 million to $50 million.[308] OCC argues that the $20 million cost threshold be increased to $50 million in order to be more closely aligned with the known costs of Filing Parties' starter projects. Additionally, OCC states that the Commission should direct Filing Parties to remove the 5 percent of net plant requirement because it may result in

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[306] Edison Mission Comments at 15.

[307] E.ON Comments at 14.

[308] OMS Comments at 11; Iowa Board Comments at 12; NIPSCO Comments at 7; OCC Comments at 9.

insufficiently small projects qualifying for MVP cost allocation without providing sufficient regional benefits to meet documented federal and state energy policy mandates or laws.[309]

b. Arguments that MVP Criteria 2 and 3 Projects will Subsume RECB I and II Projects

250. MICH-CARE opposes the proposal as submitted. MICH-CARE claims that the criteria proposed by Midwest ISO to qualify a project as an MVP "would likely incent many future transmission projects to be classified as MVPs thereby shifting enormous costs across the [Midwest ISO] footprint."[310]

251. Illinois Commission, IPL, Industrial Customers, and NIPSCO argue that MVP Criterion 2 will effectively subsume the Market Efficiency Projects.[311] These parties believe that the latter type of project allocates costs in a more targeted manner which was approved by the Commission.

252. Industrial Customers assert that the $15 million difference in cost threshold between a project that would be subject to a benefit-to-cost ratio of up to 3:1 to receive a 20-percent regional postage-stamp allocation (under RECB II) and a project that would be subject to a benefit-to-cost ratio of 1:1 to receive 100-percent regional postage-stamp allocation is inappropriate. Instead, Industrial Customers argue that it would be simpler and more appropriate for Filing Parties to eliminate Criterion 2 and modify the requirements for a project to qualify as a Market Efficiency Project.

253. Similarly, Illinois Commission, IPL, Industrial Customers, Michigan Commission, and MPPA argue that Criterion 3 would essentially subsume the Baseline Reliability Project category and cost allocation developed in the RECB I proceeding and therefore, should be removed from the MVP proposal.[312] Specifically, Illinois Commission states that the distinct contributions to the need for projects to meet NERC standards are directly quantifiable in terms of power flows and other economic benefits are also quantifiable. Therefore, Illinois Commission claims that allowing Baseline Reliability

[309] OCC Comments at 9.

[310] MICH-CARE Comments at 8.

[311] *See also* Designated PJM Parties Comments and MISO Northeast Transmission Customers Comments.

[312] *Id.*

Projects and their targeted cost allocation to be absorbed by the MVP category and its postage-stamp cost allocation is unreasonable.

c. Exclusion of Projects Driven Solely by Interconnection Requests or Transmission Service Requests

254. Many parties argue that Filing Parties' proposal should not exclude transmission upgrades associated with generator interconnection requests from receiving MVP cost allocation. Integrys argues that the provisions of proposed section II.C.2.f of Attachment FF (precluding network upgrades driven by generator interconnection or transmission service requests from qualifying as MVP facilities) is inconsistent with Order No. 890 and the Generator Interconnection Procedures in the Midwest ISO Tariff (Attachment X). Integrys argues that to allow this language to stand is contrary to the filed and approved rate doctrine.[313]

255. Similarly, AWEA-WOW request that the Commission require Filing Parties to clarify the MVP criteria in proposed Tariff section II.C.2.f such that it is clear that a transmission line that supports more than one interconnection request required to meet state or federal energy policy can be considered for MVP cost allocation.[314] In this vein, Edison Mission states that the Commission should require Filing Parties to modify the proposal so that "Network Upgrades driven solely by a single Interconnection Request or a single Transmission Service request will not be considered MVPs."[315]

256. Industrial Customers also argue that in cases where a transmission project fails the benefit-cost ratio test and shows no broad-reaching economic benefit, yet is chosen for development due to un-quantified public policy objectives or reliability benefits, the cost of such projects should not be allocated region-wide.[316]

2. Answers

257. In its answer, Filing Parties state that the proposed $20 million threshold is appropriate and provides another mechanism that helps ensure MVPs are limited to projects that are regional in nature without being overly exclusive. Filing Parties state

[313] Integrys Comments at 10-11. *See also* Acciona Comments at 11.

[314] AWEA-WOW Comments at 32.

[315] Edison Mission Comments at 13.

[316] Industrial Customers Comments at 19.

that of all the Baseline Reliability Projects approved in MTEP06 to MTEP09 or pending approval in MTEP10, only 34 percent have had a total cost exceeding $20 million.[317] Thus, Filing Parties state that the Baseline Reliability Project cost allocation methodology is still pertinent since there are numerous projects that either do not meet the minimum cost threshold for MVP status or do not provide reliability or economic benefits in multiple pricing zones for the first 20 years of the project's life. Filing Parties also state that they would object to lowering the cost threshold to $5 million because that would preclude a primary means of making the distinction between projects that are generally local in nature and those that are regional in nature.

258. As to whether MVP Criterion 2 will subsume or otherwise render Market Efficiency Projects obsolete, Filing Parties state that there are many projects that will not meet either the cost threshold test or the benefits tests that will allow a project to be categorized as an MVP and therefore, the Market Efficiency Project methodology will still be utilized by projects seeking some regional cost sharing. Filing Parties reiterate that in order to qualify for regional cost sharing, an MVP must have a scope and benefits that are more regional than local. To that end, Midwest ISO states that Criterion 2 was drafted to capture projects with multiple benefits or that affect multiple zones, rather than the narrowly tailored RECB II method for Market Efficiency Projects which focus on specific and localized benefits. For example, Filing Parties contend that a transmission project that provides congestion relief in a single pricing zone would not qualify as an MVP because only a production cost savings would be realized and then only in a single zone. Filing Parties continue by stating that even if this production cost savings was realized in more than one zone, it still would not qualify as an MVP because it would only produce one type of economic benefit.

259. Filing Parties state that selecting MVP candidates from upgrades that solely arise from the Generator Interconnection process would defeat the purpose of the MVP which considers other factors. However, Filing Parties note that the MVP proposal does not eliminate the possibility that contingencies identified in a Generator Interconnection Agreement will become MVPs. Filing Parties state that the MVP proposal already accounts for the possibility that upgrades identified for individual projects in the Generator Interconnection process will also be identified (in whole or in part) as MVPs. Specifically, Filling Parties state that a network upgrade that is under consideration for inclusion in MTEP Appendix A will be listed as a contingency in the Interconnection Customer's Generator Interconnection Agreement until it is accepted. Also, projects that are identified within one year will also be incorporated into the Generator Interconnection Agreement of the relevant generators.

[317] Filing Parties October 18, 2010 Answer at 35.

3. **Commission Determination**

260. We accept Filing Parties' proposal for a $20 million minimum project cost to establish eligibility for 100-percent regional cost sharing. Filing Parties state that of all the Baseline Reliability Projects approved in MTEP06 to MTEP09 or pending approval in MTEP10, only 34 percent have had a total cost exceeding $20 million.[318] We believe that this threshold provides additional assurance that the MVP's benefits will be material to the region.

261. While we understand OCC's concern that projects should have substantial regional benefits before being allocated on a postage-stamp basis, the Commission is also concerned that rejecting the 5-percent net plant alternative will unduly discriminate against smaller transmission systems. We reject the calls of parties to raise the minimum cost threshold to $50 million because we believe such a change would inappropriately limit application of MVP cost sharing to projects that would otherwise meet the MVP criterion. However, Midwest ISO should evaluate, on an on-going basis, whether the $20 million threshold remains appropriate for the purpose of ensuring that projects provide material benefits to the region.

262. We find that there is insufficient evidence to conclude that MVP Criterion 2 projects will subsume or otherwise render the Market Efficiency Project cost allocation methodology obsolete. Criterion 2 guards against a project that provides a type of economic value confined to a localized area. For example, a transmission project that provides congestion relief in a single pricing zone would not qualify as an MVP because only one type of economic benefit is produced (i.e., production cost savings), with benefits accruing to load in only a single pricing zone. However, even if the benefits accrued to two or three pricing zones, the project would still not qualify as an MVP because the sole economic benefit is limited to production cost savings in a local area bordering two or three pricing zones.[319] The Criterion 2 methodology contrasts with a Market Efficiency Project cost allocation method that is designed to allocate the costs of local, economically efficient projects to the identifiable beneficiaries of those projects. That 20 percent of the costs associated with Market Efficiency Projects with a voltage rating of 345 kV and higher is allocated regionally is not inconsistent with the idea of allocating the majority of costs of local, economically efficient projects to local beneficiaries. We further note that the cost threshold of the Market Efficiency Project is $5 million whereas the cost threshold for the MVP is $20 million. Finally, we note that

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[318] *Id.*

[319] *Id.* at 31.

Midwest ISO has indicated that the Market Efficiency Project category is being reviewed by Midwest ISO and its stakeholders.

263. We find that there is insufficient evidence to conclude that MVP Criterion 3 projects will subsume or otherwise render the Baseline Reliability Project cost allocation methodology obsolete. We note that the cost threshold of the Baseline Reliability Project is $5 million whereas the cost threshold for the MVP is $20 million. Projects qualifying as Baseline Reliability Projects with capital costs less than $20 million will not qualify as MVPs, unless they are 5 percent of the constructing transmission owners net transmission plant. In this regard, Filing Parties note that for Baseline Reliability Projects approved in MTEP 06 to MTEP 09 or pending approval in MTEP 10, only 34 percent of the projects had a total cost exceeding $20 million. Additionally, a Baseline Reliability Project that costs more than $20 million can only qualify as an MVP under Criterion 3 if it provides economic benefits over a twenty year period in excess of the annual revenue requirements of the project over twenty years on a present value basis (i.e., must have a benefit-to-cost ratio greater than 1.0 considering only the economic benefits based on Criterion 3. Many projects will qualify as Baseline Reliability Projects and, while possibly providing economic benefits, will not meet the benefit-to-cost ratio test for MVPs.[320] The Baseline Reliability Project cost allocation method is designed to allocate the costs of local reliability projects to the identifiable beneficiaries of those projects as determined by the Line Outage Distribution Factor methodology. That 20 percent of these costs associated with Baseline Reliability Projects with a voltage rating of 345 kV and higher is allocated regionally is not inconsistent with the idea of allocating local reliability projects to local beneficiaries.

264. We will not require Filing Parties to remove or modify the proposed requirement that projects driven solely by generator interconnection or transmission service requests not be included as MVPs. We believe that the proposed criteria are appropriate given the different nature of these processes in Midwest ISO – the transmission planning process will have a regional outlook whereas the generator interconnection process is largely reactive to requests for interconnection. However, we note that the fact that these processes are different does not prevent customers in the interconnection and transmission service queues from benefiting from MVPs.

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[320] *Id.* at 35-36.

C. Proposals Regarding Generator Interconnection Cost Allocation and Planning Processes

1. 90-Percent Participant Funding and Shared Network Upgrades

265. Under Filing Parties' proposal, the interconnection customer will continue to pay 100 percent of the costs of network upgrades to the transmission owner in advance, subject to reimbursement under Attachment FF of the Tariff. (The level of reimbursement is generally 10 percent for the cost of required network upgrades rated at 345 kV or above; there is neither cost reimbursement nor cost sharing for Network Upgrades rated below 345 kV.)[321] The transmission owner may select one of two repayment options through which to reimburse the customer.

266. Filing Parties propose revisions to Attachment X and Attachment FF of the Midwest ISO Tariff to require later-coming interconnection customers who benefit from network upgrades built by an earlier interconnection customer to pay a portion of the costs of the upgrades that qualify as SNUs. Filing Parties state that without such contributions, interconnecting generators confront a "first mover/free rider" problem (i.e., only the first party to interconnect must pay, so subsequent generators use their upgrades at no additional charge). Network upgrades that are eligible for designation as SNUs are those that: 1) have a Generator Interconnection Agreement effective date that is after July 15, 2010; 2) have an actual in-service date that is less than five years from the date of a System Impact Study that identifies them as being eligible for contribution; and 3) Midwest ISO has determined to benefit a later-interconnected interconnection customer.[322] The later-interconnected generator or generators will contribute to the cost of the SNU in proportion to its use of the upgrade.

267. As described above, Filing Parties expect that some projects that would have been characterized as network upgrades in the past may fall under the new MVP category. Under the proposal, the remaining network upgrade projects will be subject to the existing cost allocation methodology and the cost allocation percentages will not change. Midwest ISO states that as a result of the Tariff revisions, it expects an overall reduction in the total costs allocated to generator interconnection customers as a whole, relative to current rules, because some of these network upgrades will qualify as MVPs. Also, Midwest ISO states that some network upgrades financed by first movers may become eligible for cost sharing as SNUs thereby further reducing the financial impact on generator interconnection customers.

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[321] Exceptions to this policy have been granted to ITC, and METC, and ATC.

[322] Filing Parties July 15, 2010 Filing, Transmittal Letter at 31-32.

a. **Comments**

268. Xcel supports retaining the interim GIP cost allocation methodology. It states that allocating costs of network upgrades to generators provides protection from disproportionate allocation of costs to customers in close geographic proximity to upgrades.[323]

269. Xcel adds that the introduction of the MVP category of facilities will limit the scope of GIP network upgrades to facilities that resolve local issues associated with interconnection. Xcel believes that the combination of 100-percent socialization of MVPs and direct assignment of GIP facilities sends appropriate price signals to generation developers to locate resources close to the existing transmission system or MVP facilities.[324]

270. Iowa Board generally supports Filing Parties' proposal. However, it argues that rolling network upgrades into MVPs gives developers an incentive to argue for accelerated MVP expansion in order to avoid directly assigned costs under the GIP process. Iowa Board recommends that Midwest ISO specify a "scope" and "pace" for MVP development of at least 2-3 years between MVP build outs.[325]

271. Many other commenters request changes to the interim cost allocation policy. ITC Companies-Wolverine, Midwest Generators, and AWEA-WOW state that the GIP cost allocation policy was approved only on an interim basis. AWEA-WOW believe that direct assignment of most costs for GIP facilities is not roughly commensurate with benefits accrued; ITC Companies-Wolverine and Midwest Generators find the GIP cost allocation, on a long-term basis, to be inconsistent with cost causation principles.[326] E.ON also states that Filing Parties ignore precedent that requires that costs be roughly commensurate with benefits.[327] E.ON claims that because GIP facilities are part of an

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[323] Xcel Comments at 13-14.

[324] *Id.* at 14-15.

[325] Iowa Board Comments at 7-10.

[326] Specifically, Midwest Generators state that, on a long-term basis, the GIP cost allocation methodology unjustly and unreasonably allocates costs of network upgrades to generators rather than the true beneficiaries of those upgrades. Midwest Generators Comments at 8-9.

[327] E.ON Comments at 30 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559).

integrated transmission system, it is inconsistent with cost causation principles to allocate all costs to interconnecting generators. In addition, Midwest Generators claims that the GIP cost allocation methodology is inconsistent with Commission precedent. They contend that direct assignment of network upgrade costs to generators does not ensure that costs are commensurate with benefits, and uses exclusive participant funding in direct contradiction of the Transmission NOPR.

272. E.ON argues that Filing Parties fail to demonstrate that the Commission should apply "regional flexibility" under the "independent entity" standard in Order No. 890 to allow the retention of the 90-100 percent direct assignment provision.[328] ITC Companies-Wolverine add that the GIP cost allocation methodology disadvantages new generation resources and independent power producers, and cannot be justified as a "regional entity" variation from Order No. 2003. Accordingly, ITC Companies-Wolverine request that the Commission require Midwest ISO to revert to the *pro forma* cost allocation methodology under Order No. 2003 until Midwest ISO develops something more consistent with the Transmission NOPR and the MVP cost allocation methodology.[329]

273. E.ON believes that "underlying circumstances" no longer justify direct allocation of costs to interconnection customers. It states that Filing Parties have developed a means to correct disproportionate impacts and recover costs for large transmission upgrades. Rather than retain the current cost allocation methodology, E.ON recommends that costs of GIP facilities be allocated system-wide as well.[330] AWEA-WOW contend that because load benefits from network upgrades, it is inappropriate to treat these facilities as "sole use" facilities.[331]

274. Furthermore, Midwest Generators argue that the GIP cost allocation methodology is not necessary to avoid disproportionate allocation of costs to transmission zones. Midwest Generators insist that an appropriate methodology ensures that the costs of all network upgrades are allocated to beneficiaries, not just costs of MVPs.[332]

[328] *Id*. at 25-31.

[329] ITC Companies-Wolverine Comments at 9-11.

[330] E.ON Comments at 19-21.

[331] AWEA-WOW Comments at 35-40.

[332] Midwest Generators Comments at 11-12.

275. Midwest Generators also claim that direct assignment of costs would increase energy cost for consumers, eliminating many of the benefits of renewable generation. Midwest Generators state that costs of non-MVP network upgrades are ultimately reflected in power purchase agreements, potentially pricing wind resources out of the market and creating a significant financial obstacle to generators in areas not near an MVP facility.[333]

276. Midwest Generators assert that interconnection customers will not receive proper price signals from MVP facilities in a timely manner. Because of the time required to designate a project as an MVP, developers will be forced to make siting decisions without knowing whether their projects will benefit from MVPs. Midwest Generators believe that this would not be a problem if costs of network upgrades were allocated to their true beneficiaries.[334]

277. Midwest Generators further argue that the GIP cost allocation methodology contradicts state policy recognizing the benefits of renewable energy to load. For this and the above reasons, Midwest Generators request that the Commission require Midwest ISO to develop a mechanism to allocate costs of non-MVP facilities to load that benefit from generator interconnection.[335]

278. Midwest Generators further state that Filing Parties overstate the impact of MVPs on generator interconnection costs as justification for retaining the GIP cost allocation methodology. Midwest Generators assert that Filing Parties mistakenly assume that MVPs would have otherwise been directly allocated to interconnection customers, when in reality it is unlikely Midwest ISO would be able to demonstrate that the facilities meet the "but for" standard.[336]

279. E.ON asserts that Filing Parties cannot justify retaining the GIP cost allocation methodology based on the potential cost mitigation provided by the MVP and SNU facility classifications.[337] E.ON identifies four alleged practical shortcomings of Filing Parties' proposal with regard to mitigation of direct assignment costs. First, E.ON claims that the strict MVP criteria will prevent many projects from qualifying as MVPs, thereby

[333] *Id*. at 12.

[334] *Id*. at 13-14.

[335] *Id.* at 14.

[336] *Id*. at 10-11.

[337] E.ON Comments at 21.

lowering the mitigation value. Second, E.ON states that because it will be at least five years before the first MVP comes into commercial operation, the potential mitigation will be substantially delayed. Third, E.ON alleges that the actual mitigation benefits of MVPs are speculative, as there is no guarantee that a developer will choose to site a project next to an MVP. Finally, E.ON states that the SNU process would mitigate direct assignment costs for a project only insofar as other developers choose to site their own projects nearby.[338]

280. E.ON also claims that Filing Parties have not considered the extent to which direct assignment of costs to generators causes market inefficiencies or market distortions. It states that Filing Parties discarded an injection/withdrawal methodology that allocated 20 percent of costs to generators because of market distortions resulting from direct assignment costs. E.ON believes that the same concerns apply to 90-percent/100-percent direct assignment as well.[339]

281. E.ON asserts that direct assignment of costs creates a "free rider" problem, as not all beneficiaries of GIP facilities would bear costs for their construction. Because generators would be forced to recover the cost of network upgrades through power sales, E.ON states that a single entity would be forced to effectively subsidize all of Midwest ISO system users' "beneficial reliance on that facility."[340]

282. E.ON also states that direct allocation of costs for GIP facilities perpetuates barriers to entry for transmission and generation development. Interconnection requests faced with large direct assignment costs would be forced to drop out of the queue, resulting in lower wind penetration and decreasing transmission construction. E.ON asserts that the SNU concept will not significantly reduce these barriers, as generators will still be forced to bear all costs initially.[341]

283. E.ON's preferred remedy is that the Commission require Midwest ISO to allocate 100 percent of costs of integrated transmission facilities to all Midwest ISO system users. In the alternative, E.ON asks the Commission to require Midwest ISO to revert back to allocating 50 percent of costs of integrated transmission facilities to all Midwest ISO

[338] *Id*. at 21-25.

[339] *Id*. at 31-33.

[340] *Id.* at 33-34.

[341] *Id.* at 35-37.

system users. E.ON suggests that these remedies would create an appropriate balance between beneficiaries and costs, and eliminate market distortions.[342]

284. Edison Mission states that Filing Parties' own witness agreed that 345 kV was not a justifiable cutoff for cost allocation purposes. Network upgrades at lower voltages, such as 230 kV or 161 kV, also serve regional purposes. Accordingly, Edison Mission requests that the Commission require regional cost sharing for GIP facilities at or above 161 kV.[343] Edison Mission also asserts that 10-percent regional allocation is a *de minimis* value, and requests that the Commission require Filing Parties to allocate at least 25 percent of the cost of facilities to load.[344]

285. ITC Companies-Wolverine assert that the creation of the MVP category means that the rationale behind Midwest ISO's GIP cost allocation methodology is no longer applicable. ITC Companies-Wolverine state that participant funding for network upgrades necessary to interconnect generators is inconsistent with both the objective of Filing Parties' proposal and the cost allocation principles from the Transmission NOPR.[345]

286. AWEA-WOW argue that the reimbursement options for network upgrades impose significantly different costs over time on interconnection customers. They, along with Oak Creek and Midwest Generators, ask the Commission to require Midwest ISO to give the interconnection customer the right to select which reimbursement option applies to the customer.[346]

287. E.ON claims that giving the transmission owner the right to choose the method of reimbursement is unjust, unreasonable and unduly discriminatory. First, because the transmission owner is not independent, these provisions do not meet the independent entity variation standard. Second, because the original developer pays a different amount of costs under the monthly payment option, there will be an unduly discriminatory and disparate result among similarly situated generators. Third, the options create barriers to entry by providing incentive for generators to site in zones where the transmission owner

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[342] *Id.* at 37-38.

[343] Edison Mission Comments at 21-22.

[344] *Id*. at 22.

[345] ITC Companies-Wolverine Comments at 8-9.

[346] AWEA-WOW Comments at 43-44; Oak Creek Comments at 11; Midwest Generators Comments at 18-19.

generally chooses the lump sum repayment option. Fourth, the disparate reimbursement methods and aforementioned siting incentives for the lump sum repayment option place generators subject to monthly repayment at a competitive disadvantage. Finally, the monthly payment option forces generators to pay more than they would otherwise have to, enabling unjust and unreasonable collections for transmission owners.[347]

288. Several commenters address the 100-percent reimbursement policy that is specific to ATC and ITC. Alliant faults the MVP proposal for not comprehensively addressing GIP cost allocation procedures for the entire Midwest ISO footprint. Alliant states that ATC and ITC's pricing zones allow for 100-percent reimbursement to the interconnection customer regardless of whether it has exercised discipline in siting its facilities. Alliant states that maintaining such cost allocation in ATC and ITC's pricing zones clearly and unduly discriminates against ATC and ITC's load rather than charging the party that benefits the most from such projects, the generator. For example, if a potential generator is considering two alternate and otherwise comparable siting locations, one in the Xcel footprint and one in the ITC Midwest footprint, the generator would recognize a significantly lower total cost of siting in the ITC Midwest footprint because all of the GIP costs would be passed along to ITC Midwest load rather being charged to the generator.[348] Wisconsin Industrials claims that ATC's 100-percent reimbursement policy provides wind developers an incentive to site generators in Wisconsin regardless of whether it is an efficient siting location or not.

289. Wisconsin Industrials prefers that the Commission eliminate ATC's 100-percent reimbursement policy and replace it with the generic 90-percent/10-percent allocation methodology used by the rest of Midwest ISO (excluding ITC).[349] Alliant suggests that the Commission require ATC and ITC to submit proposed revisions to their respective GIP reimbursement policies to conform to the proposal in this proceeding. If the Commission believes that there is insufficient information or legal basis in this record to require ATC and ITC to file conforming changes to their GIP Network Upgrade reimbursement policies, Alliant suggests that the Commission require Filing Parties to submit a compliance filing prior to the Commission's final decision in this proceeding that would provide an analysis of the relative prospective impact of the disparate reimbursement processes based on information available from the Midwest ISO generation interconnection queue for ATC and ITC's footprints. Alliant believes that such an analysis would provide the Commission with a more complete understanding of

[347] E.ON Comments at 42-51.

[348] Alliant Comments at 13-17.

[349] Wisconsin Industrials Comments at 18-22.

the cost implications of the proposal in this proceeding and would further clarify that the disparate treatment results in the unintended consequence of disproportionate GIP Network Upgrade costs being allocated to the network transmission customers of ATC and ITC.[350]

290. Iowa Board also states that the continued allowance made to ATC and ITC for 100-percent reimbursement of network upgrades under the GIP process creates distortions in generation siting and selectively eliminates Filing Parties' intended price signals. Therefore, Iowa Board further recommends that continuing allowance of 100-percent reimbursements should be contingent upon state-specific approval.[351] Similarly, Wisconsin Commission asserts that ATC's 100-percent reimbursement policy results in unjust and unreasonable charges to ATC ratepayers. Wisconsin Commission states that this policy sends inefficient pricing signals to generators, and may result in ATC's customers subsidizing generator interconnection in other states through construction of network upgrades in their own zone. Accordingly, Wisconsin Commission requests that the Commission eliminate 100-percent reimbursement policies for transmission owners in Midwest ISO.[352]

291. Michigan Commission supports continuation of existing cost allocation methodologies for network upgrades necessary for generator interconnection. It specifically supports the 100-percent reimbursement policy for the ITC, ATC, and METC pricing zones for qualified network upgrades.[353]

292. Other comments seek changes to the existing RECB processes. While MidAmerican generally supports the proposed MVP and SNU processes,[354] it asserts that the RECB II cost allocation procedures have not been working as intended. MidAmerican states that from MTEP 2006 through MTEP 2009, the RECB I cost allocation methodology for Baseline Reliability Projects shared approximately $2.48 billion; in contrast, RECB II only shared $5,655,000 between MTEP 2008 and MTEP 2009.[355]

[350] Alliant Comments at 17-18.

[351] Iowa Board Comments at 12-14.

[352] Wisconsin Commission Comments at 10-11.

[353] Michigan Commission Comments at 18.

[354] MidAmerican Comments at 24-25.

[355] *Id.* at 18-19.

293. MidAmerican asks the Commission to require Midwest ISO to revise the RECB II cost allocation methodology to meet the requirements of the Transmission NOPR and submit a compliance filing within one year. Alternatively, MidAmerican requests that the Commission "require the Midwest ISO to modify the RECB II cost allocation methodology to incorporate a benefit/cost ratio hurdle of 1.0:1."[356]

294. Wisconsin Commission states that it is unclear what projects would be designated as GIPs. Wisconsin Commission believes that further clarification to the GIP definition is necessary.[357]

295. AWEA-WOW support the SNU mechanism to address the "first mover/late comer" issue,[358] arguing that it will help to ensure that cost allocation is more accurately aligned with the benefits of generator-funded upgrades when additional parties come online and benefit from upgrades funded by first movers. AWEA-WOW recommend amending the process by extending it from 5 to 10 years after the online date of network upgrades that are later determined to be SNUs, as future generators would benefit from the upgrade beyond the first five years from the time the generation comes online. AWEA-WOW also suggest providing a mechanism that would identify transmission service requests and new load additions that benefit from upgrades that others fund, and requiring those additional parties to contribute the costs of SNUs. Finally, AWEA-WOW ask the Commission to require Midwest ISO to allow the generator, not the transmission owner, to decide whether the generator is paid for network upgrades under Option 1 or Option 2.

296. E.ON states that Filing Parties inappropriately justify the five-year period for SNU cost allocation using a transmission planning concept, the near-term planning horizon. E.ON asserts that the benefits provided over the full life of a project (generally 30-40 years) and the length of time required to build an MVP facility require a longer period for SNU cost allocation, such as ten years.[359]

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[356] *Id.* at 20.

[357] Wisconsin Commission Comments at 9.

[358] Commenters use several variations on this term, including "late comer/free rider," and "first mover/free rider." For simplicity, we refer to the issue as "first mover/late comer."

[359] E.ON Comments at 39-42.

297. Xcel states that Filing Parties' proposal mitigates the "first mover/free rider" issue because later interconnection customers who benefit from or impact upgrades within 5 years are assessed a portion of the cost of these upgrades. This, Xcel says, ensures that the cost of generator interconnection network upgrades are allocated both to those who cause the upgrade and those who benefit from them; moreover, the five-year time limit is appropriate to provide cost transparency for generators that initially fund SNUs and generators that interconnect later.

298. Xcel notes that the proposal also mitigates the timing risk associated with projects that have been identified as GIP network upgrades required for a customer's or customers' interconnection, but which are also under consideration as MTEP projects. Xcel states that under the proposal, an identified GIP network upgrade that is ripe for approval in the MTEP process would be included in the Generator Interconnection Agreement, and noted as a contingency that may require interconnection customer funding. If the upgrade is approved and receives cost allocation in MTEP within a specified period of time, then the upgrade will be funded pursuant to its MTEP cost allocation designation, and Midwest ISO will amend the Generator Interconnection Agreement to remove the funding contingency.

299. Xcel also contends that the filing presents an equitable, balanced proposal for cost allocation associated with MVPs and SNUs, and proposed other enhancements to the generator interconnection queue process. Xcel states that the proposed Tariff revisions are generally supported by many stakeholders and state regulatory agencies in Midwest ISO region, and that they represent a delicate balancing act given stakeholders' competing interests. It urges the Commission to find that the proposal is a well-reasoned compromise with support across stakeholder sectors.

300. NextEra and Edison Mission argue that the test for whether the later generator needs to contribute to the earlier one is inadequate (NextEra) and creates an unreasonably high threshold (Edison Mission). NextEra and Edison Mission both take issue with the requirement of the distribution factor having to exceed 20 percent. NextEra notes that this is higher than the test used to evaluate the initial interconnection. It notes that under "system intact" conditions, Midwest ISO proposes to use a 20-percent impact test for SNUs, but only a 5-percent impact test for determining whether the network upgrade was needed in the first place. Edison Mission states that the screen is 5 percent or 10 percent in PJM and in NYISO.

301. NextEra and Edison Mission each express concern that these tests will inhibit cost sharing, either by decreasing the number of later-identified interconnection customers that will be identified to share SNU costs, or by inhibiting findings that an SNU exists. NextEra says that Midwest ISO's proffered justification does not justify the disparate treatment of the first mover from the late comer, while Edison Mission contends that this does not equitably assign costs to all beneficiaries. NextEra suggests that the

Commission require Midwest ISO to modify the proposal to address the free rider issue, and that the most equitable way to do this is to use the same sensitivity test for SNUs and for Network Upgrades. Similarly, Edison Mission asks the Commission to direct Midwest ISO to: 1) use a 5-percent distribution factor screen to determine whether a later-identified interconnection customer benefits from an SNU; 2) give the first-moving interconnection customer, not the transmission owner, the choice of selecting between SNU repayment Option 1 and Option 2; 3) clarify that Network Upgrades funded by interconnection customers through a Facilities Construction Agreement or Multi-Party Facilities Construction Agreement with an effective date after July 15, 2010 are eligible for SNU status; and 4) develop a method for determining whether transmission service customers and new load additions benefit from SNUs and revise the Tariff to implement cost sharing by transmission service customers and new load additions, as well as later-identified interconnection customers.

302. Integrys recommends modifications to the SNU provisions to broaden the SNU cost sharing beyond subsequent interconnecting generators to include all beneficiaries of the network upgrades. It contends that the SNU provisions are the sole means for equitable cost sharing for non-MVP network upgrades financed by a particular generator but beneficial to broad classes of transmission system users. Integrys argues that the provisions arbitrarily restrict cost sharing to new generation interconnection customers, when multiple current and yet-unknown future users of the transmission system are likely to benefit from network upgrades built to accommodate new generation. It contends that SNU principles require that the generator causing the upgrade to be built recover that portion of the network cost from all current and future beneficiaries, and that it is arbitrary and unreasonable to require such cost sharing for MVPs and not for smaller upgrades that also provide multiple benefits. While the SNU cost-sharing is "simple in concept and of obvious equity,"[360] Integrys advocates that the Commission order accepting the MVP and GIP Tariff provisions direct Midwest ISO to submit Tariff amendments to include as SNU cost-payers all beneficiaries of network upgrades, especially those that have not qualified for MVP status.

303. Wisconsin Industrials note that Filing Parties have made considerable attempts to lesson the burden for generator interconnection projects to address the "first mover/late comer" issue by providing for projects that join the queue later than the first movers to share in the cost of network upgrades. Wisconsin Industrials argue that this approach is fair, and that it should be used to cover all costs caused by generator interconnection projects, including those that are now being proposed as MVPs. Wisconsin Industrials contend that by designating transmission investments as MVPs that were previously

[360] Integrys Comments at 14.

considered interconnection upgrades, Filing Parties are creating another major free rider issue where the generator interconnection projects will be free riders to the load that would underwrite this investment.

b. Answers

304. MidAmerican answers that reducing the allocation of costs for network upgrades to interconnection customers increases the potential for inefficient generation development.[361]

305. In their answer, Filing Parties reaffirm theirs statement that the circumstances underlying the interim GIP cost allocation proposal still exist. Filing Parties argue that the ratio of megawatts of interconnection requests to load in western zones remains unacceptably high, making direct assignment of costs to generators necessary.[362]

306. Furthermore, Filing Parties state that placing most costs on the generator upfront, with costs possibly shifted to later interconnecting generators through the SNU mechanism, is reasonable considering that PJM customers pay the full cost of interconnection.[363]

307. Filing Parties also answer that changes to cost allocation measures place generators under different rules, but that this is not necessarily inappropriate. As an example, Filing Parties refer to the previous change in cost allocation procedures from 100-percent reimbursement to 50/50.[364]

308. Filing Parties assert that the GIP cost allocation methodology is not full participant funding, because it only assigns costs that are not shared to generators. Overall, Filing Parties believe that the combination of MVPs and SNUs will reduce the overall financial burden on generators.[365]

309. In addition, Filing Parties state that the SNU and Common Use Upgrade processes track current and future beneficiaries in a timely manner. As such, Filing Parties believe

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[361] MidAmerican October 8, 2010 Answer at 3-4.

[362] Filing Parties October 18, 2010 Answer at 55-56.

[363] *Id.* at 56.

[364] *Id.* at 57.

[365] *Id.* at 57-58.

that Filing Parties' proposal allows participants, investors, and others to make facility construction choices on an informed basis.[366]

310. Filing Parties also argue that it is not obligated to guarantee what upgrades will be proposed as MVPs or how they will be funded, and therefore the proposal is not overly speculative.[367]

311. Furthermore, Filing Parties state that the 10-percent allocation to load for facilities 345 kV and above is derived from the 20-percent postage-stamp allocation for Baseline Reliability Projects of the same voltage. Filing Parties state that this proposal merely retains the regional allocation from the 50/50 cost allocation methodology, where 10 percent was 20 percent of the 50 percent reimbursed to the generator. Filing Parties assert that because Baseline Reliability Projects below 345 kV do not get postage-stamp allocation, it is appropriate that GIP facilities below 345 kV are treated similarly.[368]

312. Filing Parties claim that the Commission has previously allowed Midwest ISO to deviate from the *pro forma* cost allocation methodology, and Filing Parties have shown that their proposal meets the independent entity variation standard. As such, Filing Parties believe that it is not necessary to require Midwest ISO to use the *pro forma* cost allocation methodology.[369]

313. In addition, Filing Parties state that the right of a transmission owner to select the reimbursement method for network upgrades was established during the original RECB filing. Filing Parties assert that the proposal does not modify these procedures outside of adapting them to the SNU process, and that commenters have not shown that transmission owners have selected reimbursement methods in a unduly discriminatory manner.[370] Filing Parties claim that the Commission considered, and rejected, arguments that these provisions are contrary to Order No. 2003 in the original RECB filing.[371]

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[366] *Id.* at 58.

[367] *Id.* at 58-59.

[368] *Id.* at 59-60.

[369] *Id.* at 60-61.

[370] *Id.* at 85-87.

[371] *Id*.

314. E.ON disagrees with Midwest ISO's answer regarding the transmission owner's right to choose the method of reimbursement. E.ON states that there was never any direct challenge to these provisions in the original RECB filing, so the Commission could not have rejected any arguments at that time. In addition, E.ON argues that while there is no evidence that transmission owners have used this right in an unduly discriminatory manner, the opportunity to do so still exists and must be addressed. E.ON claims that regardless of whether arguments against the repayment provisions represent collateral attacks, the Commission retains the authority to assess whether approved tariff provisions remain just and reasonable pursuant to FPA section 206.[372]

315. Filing Parties also reply that because ATC and ITC's methodologies have been approved by the Commission and because the instant proposal includes no changes to those approved methods, it would be inappropriate for the Commission to entertain such changes in this proceeding.[373]

316. E.ON argues that Filing Parties' proposal is noncompliant with the Commission's directives in Docket No. ER09-1431-000. E.ON states that Filing Parties' answer does not provide any information not included in the informational reports submitted in Docket No. ER09-1431-000, and at no point did Filing Parties attempt to identify benefits to load, generators, and other entities as directed by the Commission.[374]

317. E.ON also asserts that Filing Parties' proposal is inconsistent with cost causation principles. E.ON claims that Filing Parties justified the MVP process through the system benefits of an integrated system and regional usage of MVP facilities, while ignoring the fact that GIP upgrades have a similar impact. Accordingly, E.ON believes that Filing Parties have not and cannot show that load and other entities receive no benefits from GIP facilities.[375]

318. Furthermore, E.ON states that Filing Parties mischaracterize the "but for" standard as requiring direct assignment of network upgrade costs to generators. Rather, the "but for" standard requires interconnection customers to initially fund network upgrades, and

[372] E.ON November 2, 2010 Answer at 21-27.

[373] Filing Parties October 18, 2010 Answer at 87-88.

[374] E.ON November 2, 2010 Answer at 4-6 (citing October 23, 2009 Order, 129 FERC ¶ 61,060 at P 55-56).

[375] *Id*. at 6-10.

then receive 100-percent reimbursement. E.ON argues that Filing Parties have not shown their proposal to be consistent with the "but for" standard.[376]

319. In addition, E.ON states that Filing Parties' proposal is not acceptable under the independent entity variation standard. E.ON explains that an RTO must show its proposal produces just and reasonable rates and Filing Parties have not done so.[377]

320. E.ON also argues that the occurrence of large amounts of interconnection requests in comparison to load in western Midwest ISO does not justify direct assignment of costs for network upgrades to generators. E.ON claims that Midwest ISO is simply changing one disproportionate methodology for another. E.ON believes that an appropriate cost allocation methodology would attract investment capital to develop Midwest ISO's abundant wind resources. E.ON states that the previous 50/50 cost allocation methodology is an appropriate mechanism.[378]

321. E.ON further states that the mitigating impacts of MVPs and SNUs cost allocation does not cure the cost causation deficiency of the GIP cost allocation methodology for a number of reasons. First, E.ON claims that the GIP cost allocation methodology must be judged on its own merits. Second, there is no guarantee a transmission project will be designated as an MVP. Indeed, E.ON argues that two thirds of the transmission projects do not meet the cost threshold, and will therefore provide no mitigation benefits. Third, E.ON states that because it may be between five and ten years before the first MVP facility comes into commercial operation, the potential mitigation value is not available to generators ready to interconnect now. Finally, E.ON asserts that the SNU proposal is limited and only mitigates costs if other developers choose to site their own projects near a facility assigned to the original interconnection customer. Accordingly, E.ON reiterates its argument that the mitigation benefits of MVPs and SNUs cost allocation are merely speculative and do not justify retaining the GIP cost allocation methodology.[379]

322. Iberdrola-Invenergy state that the reimbursement method selected by the transmission owner has a significant impact on project developers. Iberdrola-Invenergy explain that the monthly charge option creates uncertainty for developers, as the charge is based on the transmission owners' fixed charge rate and can vary from one year to the

[376] *Id.* at 10-11.

[377] *Id.* at 11-12.

[378] *Id.* at 12-14.

[379] *Id.* at 14-17.

next. Iberdrola-Invenergy argue that because the transmission owners should be indifferent to the reimbursement method selected, it is reasonable that the interconnection customer have the right to choose.[380]

323. Iberdrola-Invenergy assert that the introduction of the SNU process makes it even more important that the interconnection customer have the right to choose the reimbursement method. Iberdrola-Invenergy note that the choice of reimbursement method appears to impact the material cost responsibility for generators subject to SNU allocation, as a later interconnecting generator may pay less under the monthly charge option than the lump payment option. Iberdrola-Invenergy also claim that the current provisions prevent an interconnection customer from making the most efficient reimbursement choice when considering the impacts of projects that may utilize capacity created by SNUs.[381]

324. Iberdrola-Invenergy argue that advance knowledge of the reimbursement method does not provide certainty regarding the amount reimbursed, especially when considering the new SNU process. Iberdrola-Invenergy believe that the entity bearing the financial risk should be entitled to choose how it is reimbursed, and repeats their request to allow the interconnection customer to select the reimbursement method.[382]

325. Iberdrola-Invenergy state that the right of the transmission owner to choose the reimbursement method is properly before the Commission because the revisions made to accommodate the SNU process change the costs that may be assigned to the interconnection customer. Iberdrola-Invenergy assert that the Commission has the obligation and authority to review the entirety of a new rate regime, including both cost allocation and compensation.[383]

326. Regarding SNUs, Filing Parties disagree with AWEA-WOW's proposal to use a ten-year, rather than a five-year, period for the second criteria for SNU designation (i.e., to deem generators eligible for contribution if their system impact study is completed less than ten years from that of the network upgrade that benefits them) saying that the ten-year period goes beyond the planning cycle and is too complex. Filing Parties contend

[380] Iberdrola-Invenergy November 2, 2010 Answer at 3-5.

[381] *Id.* at 5-6.

[382] *Id.* at 6-7.

[383] *Id.* at 7-9.

that because the planning horizon for generator interconnection is five years, it is sensible to limit the SNU designation to that time period.

327. E.ON opposes Filing Parties' answer and states that a ten year period would be reasonable. E.ON reiterates that the SNU is a cost allocation concept, not a planning concept, and network upgrades typically have a useful life much longer than five years. E.ON also argues that Filing Parties have not shown that a ten year period would be more complex than a five year period, and at any rate the Commission has disregarded issues of complexity in independent entity variation cases before. Accordingly, E.ON asserts that Filing Parties have provided no basis for not extending the availability period to ten years. Indeed, E.ON claims that such extension is necessary to offset the direct assignment of costs generators must bear.[384]

328. Filing Parties defends the use of a 20-percent, rather than a 5-percent, distribution factor screen for determining SNUs because the test for SNUs differs from the test for an impact on the transmission system. It argues that using 5 percent for both screens would compare the first mover and the late comer on a level playing field to determine their impact on causing the initial constraint, whereas the 20-percent distribution factor for the late comer project evaluates whether that project derives sufficient benefit from the upgrade to contribute to it. Therefore, the test is not whether the late comer would have caused a problem, but whether the late comer benefits from the solution that the first mover funded.

329. In response to arguments that additional potential beneficiaries should share in the cost of SNUs, Filing Parties state that entities other than interconnection customers should not be assessed costs because the SNU is an expansion of the generating facility network upgrade concept and is consistent with Order No. 2003. Filing Parties point out that generators remain for the length of their useful life, while transmission service requests are temporary in nature. It adds that if this argument was applied to larger upgrades, then one could claim that if load or a transmission customer should help pay for a SNU, then it should also contribute to the costs of network upgrades, Baseline Reliability Projects, Market Efficiency Projects, and even MVPs. This was not the intent underlying Filing Parties' filing.

330. In response to Edison Mission, Filing Parties clarify that they intended for network upgrades funded by interconnection customers through a Facilities Construction Agreement or Multi-Party Facilities Construction Agreement are eligible for SNU status.

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[384] E.ON November 2, 2010 Answer at 19-21 (citing SPP June 17, 2010 Order, 131 FERC ¶ 61,252 at P 15).

331. In response to Iberdrola-Invenergy, Filing Parties state that they do not propose to revise Midwest ISO's Letter of Credit requirements, and that Iberdrola-Invenergy have not shown that such changes are needed. It notes, however, that the portion of the Letter of Credit applicable to the upgrade that is later determined to be an MVP can be released when that project is listed in Appendix A. RES Americas disputes Midwest ISO's arguments, reiterating Midwest Generators' comments.

c. Commission Determination

332. The comments do not persuade us that the GIP cost allocation methodology accepted in the October 23, 2009 Order has become unjust and unreasonable, or that our approval of the MVP proposal necessitates change to the GIP cost allocation methodology. We will therefore approve Filing Parties' proposal to retain the GIP cost allocation methodology. The previously accepted GIP cost allocation remains just and reasonable, particularly when viewed as part of a package of reforms accompanying the MVP and SNU proposals.

333. Several parties challenge the GIP cost allocation methodology on the ground that the benefits of the Network Upgrades are not commensurate with the costs that the parties must bear. We disagree. The Commission explained in Order No. 2003 that independent system operators such as Midwest ISO have discretion to propose an appropriate cost allocation methodology for interconnection-related network upgrades, including providing interconnection customers with capacity rights made feasible by such projects. We note that Filing Parties' proposal does not alter the Tariff provision regarding an interconnection customer's entitlement to Financial Transmission Rights for costs not repaid.

334. We agree with Filing Parties that changes to ATC and ITC's 100-percent crediting cost allocation methodology are beyond the scope of this proceeding. We therefore reject requests by protestors to revisit these provisions.

335. We reject commenters' requests to give interconnection customers the right to select the reimbursement option for network upgrades. The provision regarding the right to select a reimbursement option was previously accepted by the Commission as just and reasonable, and Filing Parties have not proposed to revise it. It is therefore beyond the scope of this proceeding. To the extent that commenters wish to challenge the justness and reasonableness of an accepted tariff provision, the appropriate forum would be a complaint under section 206 of the FPA.[385]

[385] 16 U.S.C. § 824e (2006).

336. We will accept the SNU proposal as just and reasonable. We agree with Filing Parties that the proper test for cost sharing with regard to an already-constructed upgrade is not what effect a late-coming generator would have had on the system as it existed prior to the upgrade, but rather whether that late-coming generator will actually benefit from the upgrade. In this light, we find that the 20-percent distribution factor screen is an appropriate measure of benefits that strikes an appropriate balance between cost sharing and guarding against overcharging late-coming generators.

337. We will not require Filing Parties to amend their proposal to accommodate Integrys' request to broaden SNU cost sharing to include other classes of transmission system users. The SNU process is not intended to shift GIP upgrade costs to classes of transmission system users that would not be eligible to share in the initial funding of the upgrade. As such, it is reasonable that SNU cost sharing only apply to interconnecting generators.

2. Coordination of Generator Interconnection Process with Transmission Planning Process

338. Under Filing Parties' proposal, the timing of milestones for the MTEP transmission planning process and generator interconnection process will remain intact. Network upgrades identified through the generator interconnection process may be allocated under the MVP methodology if the upgrade is approved for inclusion as an MVP in MTEP Appendix A within the later of one year from execution or unexecuted filing of a Generator Interconnection Agreement or the issuance of the next annual MTEP Report.[386]

a. Comments

339. Multiple parties assert that Midwest ISO needs to align the timing of milestones between the MTEP transmission planning and the generator interconnection processes in Attachment X of the Midwest ISO Tariff for better coordination and identification of potential MVPs.[387] Edison Mission states that Midwest ISO needs to determine whether network upgrades that are identified in the Attachment X process should be considered MVPs, Baseline Reliability Projects or Market Efficiency Projects as part of the MTEP transmission planning process.[388] Similarly, Edison Mission states that Midwest ISO

[386] Filing Parties July 15, 2010 Filing, Laverty Test. at 33-34.

[387] Edison Mission Comments at 9-12; Iberdrola Comments at 18-24; NextEra Comments at 16-21; AWEA-WOW Comments at 34-35.

[388] Edison Mission Comments at 9.

needs to factor in transmission projects identified as potential MVPs, Baseline Reliability Projects or Market Efficiency Projects in the Attachment X process.[389]

340. NextEra states that Midwest ISO proposes at least three different provisions that are intended to minimize the chance that transmission projects under Attachment X become MVPs: 1) an MVP "must be *developed* through the transmission expansion planning process;" 2) the transmission project "must be evaluated through the [t]ransmission [p]rovider's transmission planning process and approved for construction by the [Midwest ISO] Board prior to the start of construction;" and 3) "[n]etwork [u]pgrades driven solely by an [i]nterconnection [r]equest, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered Multi Value Projects."[390] However, if a "project qualifies as an MVP and is recommended for construction both by the [Attachment X process] and the transmission expansion planning process *within the same planning cycle*, the project will be classified as an MVP."[391] NextEra argues that the proposal amounts to a snapshot rule: a one-time judgment of whether a transmission project under Attachment X can be an MVP.[392] That is, the timing has to be perfect for the transmission project under Attachment X to have a chance of becoming an MVP.

341. To illustrate its point that the MTEP planning process and the Attachment X process are separate and uncoordinated, Edison Mission provides a detailed explanation of the timing of these processes. It states that transmission owners propose new transmission projects to be included in the MTEP by September of each year, and such proposals are studied and vetted through a series of stakeholder meetings until Midwest ISO issues the draft MTEP report by July 15th of the following year. With input from stakeholders, Midwest ISO finalizes and submits the MTEP report to the Midwest ISO Board for review and approval by the end of the following year. In addition, Edison Mission explains that under the Attachment X process, once Midwest ISO receives a valid application, interconnection customers enter the next regularly scheduled Feasibility

[389] *Id.* at 10.

[390] NextEra Comments at 16-17 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 4, Original Sheet Nos. 3451-3451C) (emphasis added by NextEra)).

[391] *Id.* at 16 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 32 (emphasis added by NextEra)).

[392] *Id.* at 19.

Study, which typically takes about two weeks. Upon completion of the Feasibility Study, interconnection customers generally enter the System Planning and Analysis phase, which includes a (typically) year-long System Impact Study.[393] Interconnection customers then proceed to the Definitive Planning Phase which commences twice a year and typically takes about 120 days to complete, and which includes a review of, and potentially a re-study of, the System Impact Study.[394] Finally, Edison Mission explains that upon the completion of further milestones, interconnection customers enter the Facilities Study stage of the Definitive Planning Process, which typically takes another 120 days to complete. Edison Mission argues that under the current schedules, it would be a coincidence if the MTEP transmission planning and Attachment X processes aligned with one another. Accordingly, Edison Mission urges the Commission to direct Midwest ISO to consider altering the timing of the MTEP transmission planning and Attachment X processes to permit better coordination.[395]

342. NextEra recommends a review at the end of a System Planning and Analysis phase, and/or the Definitive Planning Phase, to determine whether the facilities identified through those studies also qualify as MVPs. AWEA-WOW state that Midwest ISO transmission owners may submit a proposed transmission project for expedited treatment through the MTEP planning process in what is called an "out-of-cycle" review, allowing parties to go through the planning review and, ultimately, gain Midwest ISO Board approval for transmission additions within the current MTEP cycle rather than waiting for a future MTEP cycle. AWEA-WOW recommend that a similar process be made available to generators for reviewing projects required for interconnection that are potential recipients of MVP cost allocation treatment.[396] AWEA-WOW argue that this

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[393] Edison Mission Comments at 10-11 (Edison Mission describes the SPA phase of the System Impact Study as an ongoing study which identifies a portfolio of transmission projects in phases. Therefore, some interconnection requests waiting to be studied may enter into the SPA study sooner than their scheduled cycle start date).

[394] *Id.* at 11 (Edison Mission states upon completion of the Feasibility Study, the interconnection customer can be put onto a "fast track" directly into the Definitive Planning Phase of the System Impact Study).

[395] *Id.* For example, Edison Mission states that the Brookings 345 kV transmission line needed better coordination between the MTEP transmission planning and GIP processes. Edison Mission states that the Brookings 345 kV transmission line started out as a Baseline Reliability Project in the MTEP process, but then Midwest ISO inappropriately proposed it as a network upgrade in the GIP process for group study, and now Midwest ISO appropriately propose it as a "starter" MVP. *See id.* at 11-12.

[396] AWEA-WOW Comments at 34.

could help address the timing disconnect between the interconnection study process and the MTEP process.

343. Several parties recommend lengthening the “contingency period” to allow additional time to consider GIPs as MVPs. Edison Mission and NextEra claim that a one-year contingency period is inconsistent with the five-year MTEP planning horizon. Accordingly, they request that the window of eligibility be set at five years.[397] AWEA-WOW and Iberdrola question the length of the “contingency period” for the first set of MVPs. They state that contentious stakeholder discussions may delay approval of these MVPs beyond the contingency period. AWEA-WOW request that the initial period run through the beginning of the MTEP 2012 cycle; Iberdrola requests the beginning of the MTEP 2013 cycle.[398] Iberdrola argues that network upgrades identified in a System Impact Study or Facilities Study should not be eliminated from the MTEP Appendices and that customers should be able to retain their queue position during this contingency period.

344. Lastly, AWEA-WOW state that it is their understanding that a transmission line that supports more than one interconnection request required to meet state or federal energy policy can be considered an MVP and request that Midwest ISO clarify the proposed language in this regard. [399]

b. <u>Answers</u>

345. Filing Parties maintain that the MTEP and Attachment X processes are appropriately aligned. They argue that selecting MVPs from upgrades that solely arose from Attachment X defeats the purpose of the MVP process, which considers other factors. Filing Parties explain that the MVP designation will be made through the MTEP process,[400] and that many long transmission lines needed to integrate large quantities of location-constrained resources will likely be designated as MVPs.[401]

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[397] Edison Mission Comments at 13-14; NextEra Comments at 22.

[398] AWEA-WOW Comments at 33-34; Iberdrola Comments at 21.

[399] AWEA-WOW Comments at 32. Proposed section II.C.2.f states, “Network Upgrades driven solely by an Interconnection Request, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered [MVPs].” Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Original Sheet No. 3451C.

[400] Filing Parties October 18, 2010 Answer at 62 (citing Filing Parties

(continued…)

346. Filing Parties state that the identification of projects developed and planned in the Attachment X process properly allocates costs to generators that cause the need for those upgrades, and this is consistent with the funding of network upgrades by interconnecting generators under Order No. 2003.[402] In addition, Filing Parties argue that the proposal already accounts for the possibility that upgrades identified for individual projects in the Attachment X process will also be identified (in whole or in part) as MVPs. Filing Parties state that the proposal allows for a network upgrade that is under consideration for inclusion in MTEP Appendix A to be listed as a contingency in the interconnection customer's Generator Interconnection Agreement until it is accepted and, that projects that are identified within one year will also be incorporated into the Generator Interconnection Agreement of the relevant generators.

347. Filing Parties argue that it is impractical to reevaluate a project for MVP designation or to review all GIPs to determine whether they meet MVP criteria, so an out-of-cycle review process to determine the MVP status of GIPs is impractical.[403] Filing Parties maintain that providing a one-year window for an upgrade that is listed as a contingent upgrade in a Generator Interconnection Agreement, and that is under consideration in the MTEP process as an MVP, to be approved as an MVP coincides with the annual MTEP timeframe, and provides some resolution within a reasonable timeframe as to which costs will be borne by interconnecting generators. Filing Parties

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July 15, 2010 Filing, Transmittal Letter at 30-31). *See also* October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58 (acknowledging that "stakeholders may seek to plan for transmission projects on a region-wide basis to address region-wide concerns as opposed to planning merely for specific generators or load growth").

[401] *Id*. Filing Parties state that the Commission has previously recognized that location-constrained resources present unique challenges that other resources do not present and that flexibility in applying the Commission's interconnection policy may be needed to accommodate such resources. *See* October 23, 2009 Order, 129 FERC ¶ 61,060 at P 58.

[402] Filing Parties October 18, 2010 Answer at 62 (citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Utility Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007)).

[403] *Id*. at 63.

argue that absent some timelines, cost estimates for projects in the interconnection queue cannot be provided with any reasonable certainty.[404]

348. Filing Parties also disagree that the text in section II.C.2(f) of Attachment FF is vague.[405] Filing Parties argue that this text clearly prohibits upgrades driven solely by an interconnection request or a transmission service request from being considered as MVPs. They argue that this text does not eliminate the possibility that contingencies identified in Generator Interconnection Agreements will become MVPs, but retains the Commission standard that upgrades that would not have been needed "but for" an interconnection request are appropriately allocated to the interconnecting generator and that transmission service requests should similarly bear the costs of any upgrades needed to support their requests.[406] Moreover, Filing Parties state that projects designated as MVPs would necessarily be found to benefit other parties and would not be prevented by this language. Filing Parties state that MVP designation is intended to work together with the Attachment X process to encourage generators to locate near MVPs.

349. Integrys argues that Filing Parties use their answer to amend their proposal to adopt a "but for" test for excluding from MVP status network upgrades that are driven by interconnection service and transmission service requests.[407] Integrys argues that the Commission should reject the "but for" test because an answer cannot be used to amend a filing, and because Filing Parties have not provided any evidentiary support. Furthermore, Integrys states that Filing Parties incorrectly claim that the "but for" test simply retains a Commission-required standard. Integrys argues that Order No. 890 did not specify a cost allocation methodology, but only provided overall guidance. Integrys states that the Commission has required Midwest ISO to use a "but for" analysis for GIPs so that generators do not have the ultimate responsibility to pay for a transmission line that has multiple benefits.[408] However, Integrys argues that adopting a "but for" standard for network upgrades in the MTEP process for determining MVPs is different, and the

[404] *Id*.

[405] *Id*. at 64.

[406] *Id*.

[407] Integrys November 2, 2010 Answer at 1, 3-4.

[408] *Id*. at 5 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559).

Commission has not mandated this standard for interconnection service or transmission service requests in an Order No. 890 planning process.[409]

c. Commission Determination

350. As noted above, and as discussed further below, we agree with Filing Parties that MVPs should be identified as part of Midwest ISO's transmission planning process. MVP designation is intended to work together with the Attachment X process to encourage generators to locate appropriately. By definition, because an MVP must be the product of regional planning and include regional stakeholder input, and must yield corresponding regional benefits, it cannot be driven by the Attachment X process. Thus, generators that locate in areas that benefit from MVPs will see a decrease in upgrade costs. Interconnecting generators in areas without proposed MVPs (i.e., areas that lack robust transmission), and whose requests drive the need for significant upgrades, will bear those costs either alone or with other interconnection customers.[410]

351. Notwithstanding the above, existing or future customers may have business cases that are not planned with MVPs in mind and may seek MVP cost allocation for their associated upgrades. If a network upgrade identified in a System Impact Study is also being considered as an MVP and is listed in MTEP Appendix B when a Generator Interconnection Agreement is finalized, there shall be a period where the project may be declared an MVP and moved to Appendix A, releasing the generator from cost responsibility. Midwest ISO will allow one year, or until the next MTEP report, for transmission upgrades (those not solely related to interconnection requests or transmission service requests) to move through the MTEP process in case they might be identified as MVPs. During this "contingency period," the network upgrade will be listed as a contingency in the Generator Interconnection Agreement until its status has been determined. If the project is not approved, the interconnection customer will be required to fund the network upgrade.[411] The one-year contingency window provides enough flexibility to ensure that upgrades that may be categorized as MVPs are appropriately categorized as MVPs. Because one year is enough time to make this determination, we decline to adopt commenters' suggestions that a five-year window (to match the length of the MTEP process) is more appropriate.

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[409] *Id*. at 5-7.

[410] Filing Parties July 15, 2010 Filing, Curran Test. at 8 and 34.

[411] *Id.*, Laverty Test. at 33-34.

352. As discussed above, a network upgrade that is under consideration for inclusion in MTEP Appendix A will also be listed as a contingency in the interconnection customer's Generator Interconnection Agreement until it is accepted. During this time period, the interconnection customer will be on notice that it may be responsible for funding the necessary network upgrade based upon the results of the System Impact Study and can make business decisions based upon this knowledge. If the upgrade is later moved to Appendix A, the generator will benefit from knowing that its interconnection service will not be contingent on its funding of the network upgrade, but rather will be contingent only upon the network upgrade actually being in service. Further, without some timelines, costs estimates for projects in the queue cannot be provided with any reasonable certainty.[412]

353. We agree with Midwest ISO that it would be impractical for it to re-evaluate a project or to review all GIPs to determine whether they meet MVP criteria and, thus we find that it is also impractical to require an out-of-cycle review process to determine the MVP status of GIPs. Finally, with regard to section II.C.2.f of Attachment FF, we find that Midwest ISO's answer provides AWEA-WOW's requested confirmations and therefore addresses their concerns.

354. Finally, we disagree with Integrys that Filing Parties used their answer to amend the proposal to adopt a "but for" standard. We find that Filing Parties' Answer merely makes explicit what was implied in its proposal.

D. Cost Recovery

1. Proposed MVP Usage Rate

355. Filing Parties state that MVP costs will be recovered through a system usage (i.e., MWh) charge allocated to all load in, and exports from, Midwest ISO. The charge, called the MVP usage rate, will be used to recover the MVP annual revenue requirement from monthly withdrawals, exports, and wheel-through transactions, as described and calculated in proposed Attachment MM of the Tariff. The proposed MVP cost allocation "allocates costs based on usage over time."[413] Filing Parties further claim that the MVP cost allocation would not distort the markets, as opposed to distortions that might result from imposing a charge on generators and import transactions.

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[412] Filing Parties October 18, 2010 Answer at 30, 61-64.

[413] Filing Parties July 15, 2010 Filing, Transmittal Letter at 25. Here Midwest ISO contrasts its proposed usage charge with a demand charge.

a. Comments

356. AWEA-WOW, E.ON, and Alliant support the proposed usage charge. AWEA-WOW state that, since load is the ultimate beneficiary of electricity production, the proposed usage charge is consistent with Commission precedent. They contend that it is efficient to directly charge load for the transmission upgrades necessary to support electricity production and delivery. They claim that charging parties based on their benefits as they accrue reflects the changing nature of MVP beneficiaries over time. AWEA-WOW argue that alternative approaches (e.g., participant funding) that take a snapshot-in-time approach to beneficiaries would not reflect MVP beneficiary changes.[414] E.ON supports using a usage charge because it would ensure that the current users and beneficiaries of MVPs pay for the corresponding costs and thereby provide a closer allocation of MVP costs to actual beneficiaries than would a demand charge.

357. Alliant argues that MVP costs should be allocated on a usage basis. It contends that wind generation is expected to remain the predominant renewable energy source within Midwest ISO due to applicable renewable portfolio standards and that wind generation resources are primarily energy resources rather than capacity ones due to the relative inability to dispatch wind generation. Alliant contends that, while capacity-related rates were appropriate in previous years during which reliability concerns were the primary drivers of transmission interconnections, the use of the Midwest ISO system has evolved, and it is reasonable to achieve a balance that recognizes that "the transmission system is both for market efficiency (energy) and reliability (capacity)."[415] As a result, Alliant supports the proposed usage-based MVP cost allocation because it would balance the allocation of transmission costs within Midwest ISO between the usage-based and demand-based methods.

358. Minnesota Commission-Minnesota Security and OMS suggest that Filing Parties explore the possibility of a two-part rate design that collects some costs through the proposed usage charge and other costs through a demand charge. Minnesota Commission-Minnesota Security contend that a two-part rate design would mitigate the potential rate burdens placed on certain customer classes, while retaining the proposed usage charge's sensitivity to seasonal changes and encouragement of energy conservation efforts. Minnesota Commission-Minnesota Security add that a two-part rate design could also encourage demand response efforts to a further extent than could a usage charge

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[414] AWEA-WOW state that they would support pricing methods other than the proposed usage charge if the methods could reasonably allocate costs to beneficiaries, reflect the changing nature of those beneficiaries, and are not akin to participant funding.

[415] Alliant Comments at 9.

alone. OMS argues that charging for the costs of MVPs over time as expenses are incurred would be an improvement over the static cost assignments used in the past. OMS contends that a two-part rate design could capture "the year-round effects of the MVPs with the peak investment incentives of existing and future transmission and generation assets."[416] OMS adds that, as reserve margins become tighter, the relative split between a usage and demand charge could be adjusted to provide better relative incentives. OMS further recommends that Midwest ISO periodically review the cost allocation to ensure that it accomplishes Midwest ISO's objectives and does not impose unjust impacts on the system or customers.

359. Numerous other parties[417] oppose the proposed usage charge and argue that MVP costs should instead be recovered by using a demand charge. Several protestors maintain that the proposed usage charge is inconsistent with cost causation principles. ABATE maintains that the proposed usage charge does not reflect the incurrence of MVP costs or the associated benefits. It claims that the need for MVPs would be "driven by forecasted peak energy production in remote areas where wind generation is being located and their operation will be highly coincident."[418] ABATE also contends that the size of MVPs would be driven by peak system demand and not energy usage.

360. AF&PA contends that the proposed usage charge is divorced from any real attempt to determine cost causation and any consistent measure of benefits. According to AF&PA, the proposed usage charge would not distinguish between loads in constrained load pockets and energy withdrawn at other locations, causing customers in load pockets to subsidize transmission expansions that do not benefit them, even indirectly, and diverting investment away from potential renewable projects in constrained areas or in areas nearer to loads that lack subsidized transmission treatment. AF&PA claims that the proposed usage charge would be unrelated to the consumption of renewable energy for the purpose of satisfying any renewable portfolio standards and would apply equally to the consumption of coal-fired or other generation resources. AF&PA maintains that the proposed allocation is inconsistent with the Commission's reliance on locational capacity and energy markets to send correct price signals to customers about the cost of consumption and to allocate the cost of resources to customers in a fair manner. AF&PA adds that subsidizing transmission investments by singling out a particular type of resource would disfavor efficient siting decisions by inducing the development of stand-

[416] OMS Comments at 9.

[417] ABATE, AF&PA, Basin, Hoosier-SIPC, Illinois Commission, Industrial Customers, ITC Companies-Wolverine, Midwest Generators, Steel Producers.

[418] ABATE Comments at 5.

alone renewable facilities rather than more efficient combined heat and power applications that could also satisfy the applicable renewable portfolio standards.

361. AF&PA argues that, if MVP costs are to be socialized, a demand charge would be more consistent with cost causation principles. It claims that transmission systems are sized to meet peak demand, regardless of the power source, and that public policy mandates to promote renewable resources will not alter this basic engineering and economic fact.[419] AF&PA believes that Midwest ISO's currently-approved demand-based transmission charges reflect this reality, consistent with cost causation principles, and it states, for example, that PJM socializes transmission costs using a flow-based demand charge.[420] AF&PA argues that allocating costs based on energy usage would be unrelated to cost causation because, at best, energy usage is arbitrarily related to transmission expansion costs. It also asserts that the fixed costs of the transmission system do not change from moment to moment and that customers should be given price signals to reflect that long-term transmission expansion costs are driven by demand. A demand charge would allow customers to consider the costs of their consumption decisions at different times, according to AF&PA, whereas a usage charge conveys to customers that they should be indifferent as to when their consumption occurs. AF&PA submits that, by sending such incorrect price signals, the proposed usage charge would subsidize inefficient consumption by other customers and hasten the need for further transmission expansion.

362. Hoosier-SIPC argue that the proposed usage charge for MVP facilities are not consistent with cost causation principles and request that, if the Commission accepts the proposal, the Commission require the MVP rate design to utilize a demand charge. Irrespective of the motivation behind their construction, they state that MVPs would be sized according to the highest amount of energy that they would be required to carry. Hoosier-SIPC maintain that it is appropriate for entities that use the lines most heavily during those peak times to pay more than entities that use the lines to a lesser degree, or not at all, during those periods. They add that Midwest ISO charges load-serving entities based on their energy withdrawals from the Midwest ISO system as a whole and not for their usage of transmission facilities. Hoosier-SIPC argue that a demand charge would reflect that MVPs would be designed to meet the overall usage of the entire system.

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[419] AF&PA Comments at 3-5.

[420] AF&PA explains that PJM socializes transmission costs more or less broadly depending on its calculation of a power distribution factor, which measures the effect of peak power flows on the need for transmission upgrades. *Id.* at 6.

363. Industrial Customers argue that Filing Parties have not demonstrated that the estimated benefits of MVPs are dependent on energy use. They contend that it is not more effective to measure system use based upon volumetric consumption than based on monthly coincident peak demands and reserved capacity. They assert that a customer's peak demand is a good proxy for its share of total system use.

364. ITC Companies-Wolverine contend that the proposed MVP rate design is not efficient because the usage of the transmission system may vary, while the costs of transmission infrastructure do not.[421] They state that, for this reason, the proposed usage charge is not well aligned with cost causation and that a demand charge should instead be used.

365. AF&PA also argues that the proposed usage charge would muddle the relationship between cost causation and energy usage. It claims that demand-related costs would be allocated based on usage at the regional level and based on demand at the local level, resulting in "a hodge-podge allocation that divorces cost causation from usage."[422] As a result, AF&PA argues that utilities allocated significant regional costs on a usage basis would be tempted to tamper with existing demand-based local allocations, which would lead to wasteful future transmission expansions and would be detrimental because the current system is "plagued by deteriorating utilization under declining system load factors."[423]

366. Several commenters contend that using a usage charge, rather than a demand charge, to allocate MVP costs would be inconsistent with other Commission precedents. Midwest Generators request that the Commission require Filing Parties to adhere to Midwest ISO's current demand-based rate design, consistent with Commission precedent that requires charges for transmission service to be developed based on annual peak demand and charged based on reservation size. Joint Protestors contend that the proposed usage charge is inconsistent with Order No. 888 and its progeny and that the proposal does not justify its departure from the Commission's requirements.[424] Joint

[421] ITC Companies-Wolverine Comments at 15 (citing ITC Companies-Wolverine Comments, Tierney Aff. at 18-19).

[422] AF&PA Comments at 8.

[423] *Id.*

[424] Joint Protestors Comments at 29 (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats.

(continued…)

Protestors state that MVPs will not be single-use facilities for exclusive use by renewable resources because they will be integrated with existing facilities.[425] Joint Protestors claim that the integration of these facilities with existing transmission requires the continued use of the 12-month coincident peak divisor in designing the rate. They add that the costs of providing service constitute fixed costs, which are appropriately recovered using a demand charge. They state that the cost of providing the transmission necessary to transfer renewable energy is not a variable cost that will vary with the level of demand.

367. Basin argues that MVP costs should be allocated on a demand basis because peak demand, not average energy use, is considered in the planning process. Basin asserts that MTEP decisions are made primarily based on peak demand requirements, focusing on ensuring system reliability and market efficiency in meeting growth in peak load.[426] It claims that, since projects are categorized as MVPs, Baseline Reliability Projects, Regionally Beneficial Projects, or Generation Interconnection Projects only after they are chosen through the MTEP process, the categorization of a project as an MVP is not relevant to whether the decision to construct the project is more heavily driven by average transmission usage than by peak demand need. Basin argues that the charges for all MTEP projects should be developed in the same way because the projects are chosen based on the same criteria. Basin submits that MVP costs should be allocated using a demand charge, consistent with the allocation of Baseline Reliability Project and Regionally Beneficial Project costs and with the court's finding that capacity costs "are assessed to the peak-period users because it is peak demand that determines how much a utility will invest in capacity."[427] Basin adds that, while the Commission has held that

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& Regs. ¶ 31,048, at P 239, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group*, 225 F.3d 667, *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)).

[425] Joint Protestors state that, if the transmission did, in fact, stand in isolation with the single purpose of delivering renewable energy directly to certain loads, these facilities would be distribution facilities and, as such, should not be included in the transmission rate base recovered under the Midwest ISO Tariff.

[426] Basin Comments at 4 (citing Filing Parties July 15, 2010 Filing, Webb Test. at 7; Midwest ISO Tariff, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, section 1.8).

[427] *Id.* at 5-6 (citing *Louisiana Public Service Commission v. FERC*, 184 F.3d 892, 895 (D.C. Cir. 1999) (quoting *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1198 (D.C. Cir. 1989))).

off-peak users could also pay a demand charge if "there was specific evidence that peak use did not determine investment in capacity,"[428] Filing Parties present no such evidence here.

368. Steel Producers claim that the proposed usage rate is inconsistent with the Commission's traditional treatment of transmission cost allocation. Steel Producers argue that the cost of MVPs should be allocated based on demand, not usage. They assert that demand charges better reflect that the economic value of additional transmission lines is higher during periods of peak consumption than non-peak periods because peak periods suffer more severe transmission congestion and are subject to higher transmission prices.

369. Basin, Illinois Commission, and ITC Companies-Wolverine disagree with Filing Parties' argument that the proposed usage charge would better ensure that the cost allocation changes as benefits change. Basin argues that the difference between usage and demand charges is the method of measuring benefits and that cost allocations change as benefits change regardless of whether the charges are based on usage or demand. Basin argues that a demand charge would better reflect changes in consumer demand. Illinois Commission contends that the allocation of MVP costs does not address possible changes in the use of MVPs over time because the charge is based on system usage, rather than MVP usage. ITC Companies-Wolverine argue that a demand charge may also capture differences in usage over time, as customers are billed on their actual monthly usage at the time of peak demand.

370. Basin, Illinois Commission, Industrial Customers, and Steel Producers disagree with Filing Parties' argument that the proposed usage charge would better reflect the benefits of MVPs as they accrue throughout the year. Illinois Commission argues that, under the proposed usage charge, there would be no relationship between the benefits of MVPs and the MVP cost allocation based on system usage. Industrial Customers maintain that the benefits from MVPs may occur in different hours of the year, but those benefits are not necessarily evenly distributed over all hours of the year. They state that those benefits could instead be concentrated at the time of peak system demand.[429] Basin and Steel Producers assert that Filing Parties' argument would apply equally to all MTEP projects and, therefore, would indicate that the costs of all transmission projects should be allocated based on usage, rather than peak demand. Basin argues that all transmission facilities provide benefits at times other than peak load, and therefore, Filing Parties have not demonstrated why MVP costs should not be allocated based on peak demand. Basin

[428] *Id.* at 6; *see*, *e.g.*, June 2, 2005 Rehearing Order, 111 FERC ¶ 61,337 at P 87.

[429] Industrial Customers Comments, Dauphinais Aff. at P 35.

adds that Filing Parties provide no evidence that the planning criteria for local and regional facilities differ.

371. Several protestors contend that the proposed usage charge would unfairly impact high load-factor customers and benefit low load-factor ones. They explain that moving from a demand-based to a usage-based allocation method would impose higher costs on those customers that are more efficient users of the system (i.e., high load-factor customers) and, conversely, lower costs on those customers that are less efficient users of the system (i.e., low load-factor customers).[430] ABATE asserts that, rather than using energy consumption, the total peak demand placed on new transmission facilities is used to determine their capabilities, and as a result, energy consumption should not be the basis of the corresponding allocation methodology. Industrial Customers argue that the proposal would harm higher load-factor customers. Illinois Commission argues that demand charges create better incentives because, if a load-serving entity's peak demand increase, so would a demand-based MVP charge.

372. Wisconsin Industrials claim that the proposal would send a faulty price signal by benefiting customers with low load factors, which require greater amounts of load following services, rather than high load-factor customers, which have stable load profiles and use the system efficiently, thereby imposing fewer costs on the system. Wisconsin Industrials argue that the proposed usage charge risks driving out energy-intensive customers, with remaining low load-factor customers and wind intermittency causing system reliability issues and higher costs than before.

373. ITC Companies-Wolverine argue that, according to Dr. Tierney, the proposed usage charge may cause distortions in renewable energy export transactions and lead to inefficiencies in the energy market.[431] Dr. Tierney explains that Midwest ISO generators would need to structure their offers in neighboring regions to reflect the MVP usage charge, which could cause them to be dispatched out of economic merit order. She adds that the proposed usage charge would lead to higher charges for customers with high load factors.[432] They also assert that the proposed usage rate is more complicated than a demand charge and would require changes to the settlement process in place for other transmission facilities.

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[430] *See, e.g.*, Industrial Customers Comments at 42 (citing Industrial Customers Comments, Dauphinais Aff. at P 25-35).

[431] ITC Companies-Wolverine Comments at 15 (citing ITC Companies-Wolverine Comments, Tierney Aff. at 19).

[432] *Id.*, Tierney Aff. at 19.

374. Basin argues that the proposed usage charge on exports would allow customers to pay for reserved transmission capacity only when customers use it. Basin explains that firm point-to-point customers have the right to use their reserved transmission capacity at any time during the reservation term. Basin claims that it would be unjust and unreasonable to allow such customers to avoid paying for the entirety of that reserved capacity. Basin contends that, for example, the proposed usage charge would allow a customer to reserve firm point-to-point transmission capacity for an entire month and avoid paying any associated MVP charges if it does not actually transmit energy during the month. Basin argues that, in this example, Midwest ISO would either not recover its projected revenues for the MVP facilities or would shift the customers' costs to other transmission customers that cannot use the reserved capacity on a firm basis and that either alternative is unjust and unreasonable.

375. AF&PA, Illinois Commission, and MICH-CARE maintain that the proposed usage charge would be detrimental to demand response efforts. AF&PA argues that the proposed usage charge would discourage otherwise economical demand response options and skew decisions to favor the adoption of energy efficiency measures toward reductions during off-peak periods, which are easier to accomplish than during on-peak periods, by giving both types of reductions equal compensation under the proposal. Illinois Commission states that, under the proposal, a load-serving entity that increases its demand would pay the same amount as a load-serving entity that reduces its demand, assuming that their load only shifted and total consumption stayed the same. Illinois Commission argues that the Commission should reject the proposed usage rate in favor of a per-megawatt, peak demand approach. It notes that reducing peak demand could defer the need for transmission and generation investments and mitigate market power concerns and price volatility. MICH-CARE states that, when transmission costs are assigned on a megawatt basis, load-serving entities have an incentive to reduce megawatt loads using measures such as demand-side management programs. MICH-CARE contends that switching to a usage charge could eliminate these incentives, so that transmission and generation investments would supplant cheaper demand-side management programs and increase the production of negative externalities, such as carbon dioxide emissions.

376. Basin, Illinois Commission, Industrial Customers, and Steel Producers express concern regarding the application of the proposed usage charge to projects that provide reliability benefits. Industrial Customers argue that it is inappropriate to recover the costs of MVPs under Criterion 3 using a usage charge because reliability upgrades are generally driven by system peak demand, rather than energy usage. They claim that the costs of transmission upgrades undertaken to address reliability issues should be based on monthly coincident peak demand for network transmission customers and reserved capacity for point-to-point transmission customers. Basin asserts that Filing Parties' argument conflicts with MVP Criterion 3, which qualifies projects that address North American Electric Reliability Corporation or Regional Entity reliability standards,

because those standards evaluate the reliability of the system during contingencies at various load conditions. Steel Producers claim that, while MVPs may have reliability benefits, those reliability requirements are usually measured and set based on forecasted peak demand, and thus, the costs should be allocated on a demand basis.

377. Illinois Commission contends that a usage charge would be inappropriate for Baseline Reliability Projects because such projects are targeted at ensuring reliability, which is a capacity concept rather than an energy one. It states that, while a Baseline Reliability Project's benefits may accrue to more loads and in different proportions than those loads that necessitate the project, those benefits are secondary to the primary cause of the transmission facility's construction. It concludes that entities that induce known and measureable flows that are the primary cause of Baseline Reliability Projects (e.g., expected transmission facility overload) should be allocated the costs of those projects.

378. In addition, Basin disagrees with Filing Parties' argument that the proposed usage charge is appropriate because MVPs may reduce production costs. Basin contends that no correlation exists between whether a new transmission facility reduces production costs and the types of charge imposed and that this argument would justify usage charges for any transmission facility that reduces transmission congestion. Basin asserts that MVPs would likely increase production costs, rather than reduce them, by transmitting energy from new renewable resources that generally have higher "all-in costs" per kilowatt hour than existing non-renewable generation sources.[433]

379. Finally, Basin disagrees with Filing Parties' argument that the proposed usage charge is justified because only a small amount of wind generation would occur during periods of peak demand. Basin contends that transmission upgrades for wind resources are more likely determined during peak wind periods, rather than peak load periods. Basin also claims that Filing Parties' argument is equally true for all generation types because the monthly peak demands occur in only 12 of the 8760 hours of the year, and therefore, their argument would justify determining all transmission service charges based on usage. Basin notes that virtually all transmission charges are based on demand, not usage, and thus, Filing Parties' argument is invalid.

380. CPV disagrees with Filing Parties' argument that the proposed export charge is needed to avoid free riders in neighboring regions. CPV claims that customers using the Midwest ISO transmission network to export power are already assessed point-to-point transmission charges, which ensure that they are allocated the costs of all network upgrades. CPV argues that the costs of MVPs can be incorporated into the revenue requirement underlying those point-to-point charges, as they are updated routinely to

[433] Basin Comments at 8.

reflect each transmission zone's changing costs, and therefore, a separate MVP charge is unnecessary. CPV contends that the current rate design charges customers on the basis of reserved capacity, rather than usage, which ensure that dispatch decisions are unaffected by reservation charges. CPV maintains that the proposed usage charge for MVPs would affect customers' dispatch decisions because their transmission costs will depend on whether they export energy from Midwest ISO in lieu of other resources. CPV asserts that, as a result, lower-cost generation in Midwest ISO might not be dispatched whenever the difference between the variable production costs of the Midwest ISO resource and external resources is less than the MVP charge. CPV concludes that the Commission should reject the proposed usage charge and instead require Midwest ISO to adhere to its current export rate design.[434]

381. To avoid creating market distortions, Midwest Generators recommend that the Commission require Midwest ISO to adhere to its current export rate design, whereby transmission reservation charges are routinely updated to reflect the costs of all expansion facilities and where external beneficiaries will pay their allocation of MVP costs.

b. <u>Answers</u>

382. In their answer, Filing Parties disagree with protestors arguing that the MVP should be recovered using a demand charge. They argue that, while a demand charge is appropriate for the recovery of facilities primarily addressing *local* reliability issues (e.g., Baseline Reliability Projects), the proposed usage charge would be appropriate for MVPs primarily addressing *regional* issues that involve compliance with public policy requirements and the resulting provision of regional economic benefits within the Midwest ISO market. Filing Parties also contend that it is not appropriate to limit MVP cost recovery to peak demand periods because the benefits of such projects would accrue throughout all hours of the year, not just during peak demand periods. In support, they note that, in her testimony, Ms. Curran explains that "the benefits of a market-wide economic dispatch are often more significant during off-peak hours, because fewer generation resources are required and more opportunity exists to use generation in one region to serve load in another."[435] Filing Parties add that the existence of another

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[434] To the extent that the Commission accepts the proposed charge at the Midwest ISO-PJM seam, CPV argues that the Commission should require a different rate treatment at Midwest ISO's non-PJM interfaces. CPV Comments at 9.

[435] Filing Parties October 18, 2010 Answer at 72 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 13).

potentially just and reasonable approach does not render their MVP proposal unjust and unreasonable because they are only required to show that the proposal is just and reasonable, not that it is the best.[436]

c. <u>Commission Determination</u>

383. We find the proposed MVP rate design to be just and reasonable, and accept the proposed usage charge. We agree with Filing Parties that a significant portion of MVP benefits will likely accrue during off-peak demand periods and, therefore, a usage-based cost allocation methodology is consistent with cost causation principles. As Ms. Curran explains, "the benefits of market-wide economic dispatch are often more significant during off-peak hours, because fewer generation resources are required and more opportunity exists to use generation in one region to serve load in another."[437] We are not persuaded that the specific benefits associated with MVPs would likely be concentrated during peak demand periods. MVPs will produce benefits by allowing load to satisfy documented energy policy mandates or laws (e.g., enabling an increased reliance on renewable resources) that are not necessarily associated with peak demand periods and by producing economic benefits (e.g., reducing production costs) that occur throughout the year. A proposed usage charge would more appropriately reflect MVP benefits by allowing costs to be allocated during all hours of the year. Moreover, rather than making an upfront allocation of costs based on an analysis of benefits and usage at a specific point in time (as would a demand charge), the proposed MVP rate design allocates costs based on usage over time.[438] This also allows an allocation of costs to load in a manner that reflects changes in MVP beneficiaries over time.

384. We understand that alternate cost allocation methodologies could allocate MVP costs in a manner that is consistent with the Commission's cost causation principles. However, we need not consider those alternate cost allocation methodologies here. Filing Parties must prove that the proposed rate is just and reasonable, not that it is the best

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[436] *Id.* at 71 (citing *Oxy USA*, 64 F.3d at 692; *Cities of Bethany*, 727 F.2d at 1136; *Cal. Indep. Sys. Operator Corp.*, 120 FERC ¶ 61,023, at P 45 and n.34 (2008) (July 6, 2007 Order), *aff'd sub nom. Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520 (D.C. Cir. 2010); *New England Power Co.*, Opinion No. 352, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd sub nom. Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (*Town of Norwood*).

[437] Filing Parties July 15, 2010 Filing, Curran Test. at 12-13.

[438] *Id.*, Curran Test. at 9-10.

rate,[439] and we find that Filing Parties have met that burden. Protestors do not demonstrate that Commission precedent prevents the use of a usage charge for the recovery of transmission costs, and we note that the Commission has accepted usage charges in other contexts.[440] Therefore, we will accept the proposed usage charge, notwithstanding the merits of alternative allocation methodologies such as a demand charge or a two-part rate design.

385. The proposed MVP usage charge assigns MVP costs to parties in a manner that is roughly commensurate with the benefits that they are expected to receive from MVPs, consistent with a beneficiaries-pay approach to cost allocation. While several of the factors discussed by commenters, including Midwest ISO's precise method of selecting or sizing projects utilizing measures of peak demand, could be relevant under alternative cost allocation methodologies that consider the incurrence of costs (e.g., requiring generators to pay), these considerations do not inform our understanding of the incurrence of benefits due to the MVP proposal, and as such, they are not relevant here. Instead, Filing Parties rightly assert that all load would benefit from MVPs, and it is appropriate that they be allocated the corresponding costs in proportion to their relative use of the transmission system. Furthermore, we disagree with protestors' contention that Midwest ISO's use of demand charges to recover other types of costs necessitates the use of a demand charge here. Our evaluation of the appropriateness of the proposed usage charge is limited to the MVP proposal, particularly with regard to the regional public policy and economic benefits associated with MVPs. We are not persuaded that the application of a usage charge with regard to MVPs will conflict with or otherwise undermine Midwest ISO's use of alternate rate designs in other contexts.

386. Unlike a penalty charge, which is designed to provide an incentive for market participants to perform in a certain manner, our consideration of the proposed MVP rate design is focused on whether it produces a rate that assigns costs in accordance with cost causation principles. While protestors argue that the Commission should consider whether the proposed rate also creates desirable incentives (e.g., incentives to increase demand response and customers' load factors), none of these arguments demonstrate that the proposed rate design is unjust and unreasonable. Further, we disagree that the proposed usage charge would unfairly impact high load-factor customers. Protestors do not explain how customers that merely hold reserved transmission capacity could benefit

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[439] *See, e.g.*, Opinion No. 352, 52 FERC at 61,336, *aff'd sub nom. Town of Norwood*, 962 F.2d 20 (requiring only that the Commission make a reasoned decision based upon substantial evidence in the record).

[440] *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,068, at P 101 (2008), *order on reh'g*, 126 FERC ¶ 61,320 (2009).

from MVPs without actually scheduling energy for delivery using a reservation. As such, delivered energy may be better than reserved transmission capacity at indicating the relative benefits of MVPs, which would justify allocating MVP costs to parties based on their use of transmission reservations (i.e., to those parties with relatively high load factors) in accordance with cost causation principles. Therefore, we also find Basin's argument that MVP costs should be assigned to customers with reserved capacity that do not schedule energy to be without merit.

387. We disagree with protestors arguing that a proposed usage rate is inappropriate for MVPs under Criterion 3. By definition, MVPs under Criterion 3 must create at least one type of regional economic benefit. Therefore all MVPs will create regional benefits, and therefore the associated costs may be appropriately recovered regionally through a usage rate.

388. Finally, Filing Parties explain that the MVP usage rate recovers the monthly revenue requirement for MVPs from monthly withdrawals, specifically Monthly Net Actual Energy Withdrawals (a new term defined in the proposed Tariff), exports, and wheel-through transactions. Pursuant to the proposed tariff, Monthly Net Actual Energy Withdrawals are calculated as the "volume in MWh that flows out of the Transmission System during the Operating Month at a specified location that is equal to the net positive sum of (1) the hourly time-weighted average of the Metered volume of the Commercial Pricing Node and (2) the hourly time-weighted Actual Energy Injections for Demand Response Resources and [Emergency Demand Response] resources associated to a Load Zone."[441] In her testimony in support of the MVP rate design, Filing Parties' witness states that the energy withdrawals of Demand Response Resources and Emergency Demand Response resources should be netted against their energy injections to avoid "charging [load-serving] [e]ntities for load not actually consumed."[442]

389. In light of the explanation provided by Filing Parties' witness, we are concerned that the proposed definition of "Monthly Net Actual Energy Withdrawal" may actually be inconsistent with the Filing Parties' rate design objective. As proposed, for Demand Response Resources and Emergency Demand Response resources, hourly average Metered volumes, which should already net energy withdrawals against energy injections, would again be netted against their hourly Actual Energy Injections, thereby possibly resulting in netting such injections twice. To address this concern, we will require Filing Parties to submit, in the compliance filing due within 60 days from the date

[441] Filing Parties July 15, 2008 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, First Revised Sheet No. 217.

[442] *Id.*, Curran Test. at 38.

of this order, an explanation as to how the proposed Tariff language is consistent with the rate design objectives stated by Filing Parties, and why it does not result in double netting.

2. **Financial Transmission Right and Auction Revenue Right Allocation**

390. Midwest ISO witness Mr. Todd Ramey states that the current Financial Transmission Right and Auction Revenue Right allocation design is premised on the traditional notion that local transmission is built for local needs and, thus, the investor in the transmission is also the beneficiary. The MVP concept moves to a broader funding base for transmission projects that have regional benefit. As such, Midwest ISO believes that the Financial Transmission Right and Auction Revenue Right allocation processes need to be modified so that the benefits of the MVP transmission as determined through the Financial Transmission Right and Auction Revenue Right processes are similarly socialized.[443]

a. **Comments and Answers**

391. Several parties express concern that the proposal causes unresolved issues with Financial Transmission Rights and Auction Revenue Rights. Dominion argues that, according to Mr. Ramey, the proposed export charge could result in market distortions, including short-run dispatch and Financial Transmission Right impacts. Dominion also notes that the LECG Report identified potential adverse market and Financial Transmission Right impacts due to the proposed usage charge. Designated PJM Parties also contend that Filing Parties acknowledge that its MVP proposal creates an unresolved mismatch between cost allocation and Financial Transmission Right and Auction Revenue Right allocation processes. AEP also argues that Filing Parties have not accounted for how Financial Transmission Rights would be accounted for under the proposal.

392. AMP states that if the proposal is accepted without modification to the Financial Transmission Right and Auction Revenue Right allocation processes, customers will be obligated to bear the costs of MVPs without receiving corresponding benefit in the form of Financial Transmission Rights or Auction Revenue Rights; instead Financial Transmission Rights and Auction Revenue Rights would be allocated to a different set of customers. AMP states that this inequity would be particularly grievous in the case of entities serving load outside of Midwest ISO where a transmission owner withdraws. AMP notes that Midwest ISO does not propose any corrective action here but simply

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[443] *See id.*, Ramey Test. at 8.

states that a stakeholder process is underway to consider whether changes to the Financial Transmission Right and Auction Revenue Right allocation design may be necessary. AMP asks the Commission to require Midwest ISO to correct this deficiency.[444]

393. Midwest TDUs state that Mr. Ramey's testimony appears to suggest a decoupling of Midwest ISO's allocation of long-term rights from the specific long-term power supply arrangements made and planned by load-serving entities to meet their load-serving obligations. Midwest TDU's argue that moving way from the Congressionally-directed linkage between long-term rights and the long-term power supply arrangements of load-serving entities would ignore federal laws and be a giant step in the wrong direction. Rather than hollowing-out the linkage between transmission planning, planned load-serving entity power supply arrangements, and upgrades, state Midwest TDUs, the MVP proposal should strengthen those connections consistent with FPA section 217 (b)(4). In this regard, Midwest TDUs ask the Commission to clarify that the existing language of Criterion 1 should be interpreted to encompass FPA section 217(b)(4)'s directive for planning to meet the reasonable needs of load-serving entities and to enable them to secure long-term rights for their planned long-term power supply arrangements.[445]

394. Filing Parties answer that they will address any MVP-related Financial Transmission Right and Auction Revenue Right design issues in stakeholder consultations to be held within the next four months and that it is internally studying potential issues and approaches that can be presented to the stakeholders for consideration and discussion. Filing Parties state that to the extent that it is determined that the Tariff's Financial Transmission Right and Auction Revenue Right provisions need to be modified in connection with the MVP proposal, the Tariff revisions will be filed either in the first or second quarter of 2011. Filing Parties state that the concerns raised by parties do not warrant deferment of the Commission's action on the MVP proposal.[446]

b. <u>Commission Determination</u>

395. We agree that the existing Financial Transmission Right and Auction Revenue Right allocation processes may need to be modified to be consistent with the allocation of MVP costs being accepted here. At the same time, we note that the first MVP is not

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[444] AMP Comments at 15-17.

[445] Midwest TDUs Comments at 14-16.

[446] Filing Parties October 18, 2010 Answer at 77-78.

currently expected to be in-service prior to January 1, 2013 and, thus, would not affect Financial Transmission Right and Auction Revenue Right allocations prior to the 2012-13 allocation year. Accordingly, we require Midwest ISO to address in a compliance filing, no later than June 1, 2011, what changes to its allocation of congestion rights are necessary to reflect the allocation of MVP costs being accepted here. In that compliance filing, Midwest ISO should explain how its compliance filing produces just and reasonable and not unduly discriminatory results.

3. Application of MVP Usage Rate to Exports and Wheel-Through Transactions

396. In July 2002, the Commission accepted the choices of AEP, Commonwealth Edison Company and Commonwealth Edison Company of Indiana (collectively, ComEd), and DP&L to join PJM.[447] In so doing, the Commission found that those RTO choices would result in an elongated and highly irregular seam between Midwest ISO and PJM that would "island" portions of Midwest ISO (Wisconsin and Michigan) from the remainder of Midwest ISO and would divide highly interconnected transmission systems across which substantial trade takes place. The Commission found that, without mitigation, the seam would subject a large number of transactions in the region to continued rate pancaking, impeding the goals of Order No. 2000.[448] Therefore, as a condition of accepting those RTO choices, the Commission required parties in the region to address the problem of rate pancaking across the Midwest ISO-PJM seam and instituted a proceeding under section 206 of the FPA[449] to investigate the rates for service between the two RTOs and established trial-type hearing procedures.[450] Following the hearing and issuance of an initial decision,[451] the Commission found the pancaked rates

[447] *Alliance Co.*, 100 FERC ¶ 61,137 (2002) (Alliance 2002 Order), *order on reh'g*, 103 FERC ¶ 61,274 (2003).

[448] *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[449] 16 U.S.C. § 824e (2006).

[450] Alliance 2002 Order, 100 FERC ¶ 61,137.

[451] *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 63,049 (2003).

for service wheeled through or out of one RTO to serve load in the other RTO were unjust and unreasonable and directed the RTOs to eliminate them.[452]

397. As part of the elimination of the pancaked rates between Midwest ISO and PJM, the Commission also directed Midwest ISO and PJM, under section 206 of the FPA, to work with their transmission owning members to propose, consistent with the RTOs' existing Joint Operating Agreement,[453] a method to allocate between the RTOs the costs of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO (cross border facilities).[454] The Commission ultimately accepted proposals to include in the Joint Operating Agreement methods to allocate between the RTOs the cost of cross border facilities built for reliability purposes (reliability cross border projects)[455] and cross border facilities that provide economic benefits (economic cross border projects).[456]

398. As part of its MVP proposal, Filing Parties state that all external transactions sinking outside of Midwest ISO, including those sinking in PJM, will be subject to the proposed MVP usage rate.[457] Filing Parties argue that applying the MVP usage rate to external transactions is appropriate because MVP transmission projects benefit load both inside and outside of the Midwest ISO region. Regarding the assessment of the MVP usage rate on exports to PJM, Filing Parties argue that the Commission's orders eliminating rate pancaking do not preclude the proposed Schedule 26-A surcharge on exports to PJM load that use new MVP transmission facilities. Filing Parties claim that the prior Commission orders on this subject essentially address existing transmission facilities, and expressly require the development of different rules for allocating the cost

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[452] *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,105 (2003) (July 23, 2003 Order).

[453] Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc., And PJM Interconnection, L.L.C. (Joint Operating Agreement).

[454] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168, at P 60 (2004) (November 18, 2004 Order), *order on reh'g*, 131 FERC ¶ 61,174, at P 22 (2010) (May 21, 2010 Rehearing Order).

[455] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084 (2008).

[456] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,102 (2009) (November 3, 2009 Order).

[457] Filing Parties July 15, 2010 Filing, Curran Test. at 14.

of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO.[458] Additionally, Filing Parties explain that, consistent with existing Commission directives, Midwest ISO will *not* assess charges on exports from Midwest ISO to PJM to cover the cost of existing facilities or the cost of new facilities that are not classified as MVPs.[459]

a. Comments

i. Inter-Regional Benefits

399. Alliant, E.ON, Iowa Board, ITC Companies-Wolverine, NIPSCO, and Wisconsin Commission support the proposed MVP usage rate for wheel-through and export transactions.[460] In general, they assert that loads outside of the Midwest ISO footprint will benefit from MVPs, and, therefore, an export charge is appropriate so that external loads pay their share of the cost for system upgrades from which they derive a benefit. They assert that, without an export charge, the entire cost of MVPs would be borne by Midwest ISO loads even though external loads also benefit from those projects. In addition, NIPSCO claims that charging load outside of the Midwest ISO footprint for a share of the costs associated with MVPs is consistent with cost causation principles because the external load being assessed the export charge will presumptively have determined that the price of energy being acquired from resources within or through Midwest ISO is economically beneficial even with the additional export charge.

400. ITC Companies-Wolverine assert that Filing Parties' proposal is a serviceable interim mechanism until an interregional cost allocation is in place, such as the one the Commission has proposed in its Transmission NOPR.[461] Wisconsin Commission notes, however, that the Transmission NOPR suggests that an export charge may not be the

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[458] *Id.*, Transmittal Letter at 25, n.105 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60, May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 22).

[459] *Id.*, Transmittal Letter at 25.

[460] Alliant Comments at 11; E.ON Comments at 10; Iowa Board Comments at 4-5; NIPSCO Comments at 4; ITC Companies and Wolverine Comments at 17-18; Wisconsin Commission Comments at 11-13.

[461] ITC Companies-Wolverine Comments at 18.

Commission's preferred cost allocation method, and, if the export charge is not adopted, consideration must be given to an MVP charge that is applied to generators.[462]

401. AEP, Dominion, EPSA, Exelon, and Designated PJM Parties argue that Filing Parties have not provided enough support for the proposed MVP usage rate for wheel-through and export transactions.[463] In general, they assert that Filing Parties have not demonstrated that loads outside of Midwest ISO will benefit from MVPs to an extent sufficient to justify allocating external loads a portion of the MVP costs. They argue that Filing Parties have not provided a quantitative analysis that shows how and to what extent external load will benefit from MVPs and do not consider, for example, whether external loads can meet the assumed public policy requirements without MVPs. Exelon notes that Midwest ISO's Regional Generation Outlet Study did attempt to quantify regional benefits, but it asserts that this study did not consider whether interregional benefits accrued to PJM customers.

402. AEP, Designated PJM Parties, DP&L, Dominion, and Exelon assert that the proposed MVP export charge is overly broad because MVPs may include intra-regional, interregional, and potentially low-voltage transmission projects, but the charge does not distinguish between MVPs that provide only intra-regional benefits and MVPs that also provide inter-regional benefits.[464] They argue that, other than conclusory statements, Filing Parties provide no basis to find that all MVPs will have the same external cost causers and beneficiaries, and, therefore Filing Parties have not justified requiring all exports to uniformly contribute to every MVP. DP&L argues, for example, that, if Baseline Reliability Projects meet the proposed MVP criteria, the associated costs will be exported outside of Midwest ISO, even though the projects are being constructed primarily to meet the reliability problems of Midwest ISO members.

403. AEP, EPSA and Exelon contend Midwest ISO has not explained how its proposal is consistent with sections 9.3 and 9.4 of the Joint Operating Agreement, which outlines how Midwest ISO and PJM will allocate costs of cross border facilities.[465] In addition,

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[462] Wisconsin Commission Comments at 12.

[463] AEP Comments at 6-7; Dominion Comments at 4-6; EPSA Comments at 5-12; Exelon Comments at 21-26; Designated PJM Parties Comments at 7-10.

[464] AEP Comments at 5-6; Designated PJM Parties Comments at 14; DP&L Comments at 3; Dominion Comments at 4-6; Exelon Comments at 25-26.

[465] AEP Comments at 7; AMP Comments at 6; CPV Comments at 4-10; EPSA Comments at 6-7; Exelon Comments at 16-19; Designated PJM Parties Comments at 16; FirstEnergy Comments at 41-43; Integrys Comments at 14-16; Joint Protestors

(continued…)

AEP states that under the Joint Operating Agreement, Midwest ISO and PJM share reciprocal rights on certain of each other's flowgates but notes that the MVP proposal does not include any reciprocal arrangements. Similarly, Designated PJM Parties argue that the proposed MVP export charge is discriminatory or preferential because non-Midwest ISO transmission providers do not assess reciprocal charges for exports from the non-Midwest ISO systems that are imported into Midwest ISO. They also argue that Filing Parties misapply the proposed MVP cost allocation by not considering entities more distant from Midwest ISO's borders.

ii. Rate Pancaking

404. AEP, AMP, CPV, EPSA, Exelon, Designated PJM Parties, FirstEnergy, Integrys, Joint Protestors, and Tenaska request that the Commission reject the proposal to assess the MVP usage rate on exports from Midwest ISO to PJM.[466] They contend that charging the MVP usage rate on exports to PJM would reinstitute rate pancaking between Midwest ISO and PJM, which violates prior Commission orders. They state that the Commission has previously found that pancaked rates between Midwest ISO and PJM are unjust and unreasonable and, therefore, ordered their elimination.[467] Accordingly, they argue that charging the MVP usage rate for exports to PJM violates Commission precedent and that arguments in support of charging MVP usage rate for exports are an impermissible collateral attack on prior Commission orders. In addition, Designated PJM Parties, Exelon, FirstEnergy, Integrys, and Joint Protestors state that there is no logical basis for the argument that the Commission's prohibition of rate pancaking between Midwest ISO and PJM applies only to the recovery of costs for existing facilities. Midwest Generators state that, although the Commission required Midwest ISO and PJM to develop a proposal for allocating between them the cost of cross border facilities, they contend that the Commission did not intend such proposal to include the resumption of rate pancaking.[468]

Comments at 21-26; Tenaska Comments at 4.

[466] *See*, *e.g.*, Exelon Comments at 16-17; CPV Comments at 8; Integrys Comments at 15 (citing, *e.g.*, July 23, 2003 Order, 104 FERC ¶ 61,105 at P 39).

[467] Midwest Generators Comments at 23 (citing, *e.g.*, November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60).

[468] *See*, *e.g.*, Joint Protestors Comments at 10-19; CPV Comments at 7-8; EPSA Comments at 7-11.

iii. Market Distortions and Seams Issues

405. AEP, CPV, Designated PJM Parties, Dominion, EPSA, Exelon, Joint Protestors, Midwest Generators, PJM, and Southwestern argue that assessing the MVP usage rate on exports and wheel-through transactions will cause market distortions. Several parties note that the LECG Report, as well as subsequent analysis by the Independent Market Monitor,[469] found that the application of the MVP usage rate to exports and wheel-through transactions would cause lower-cost Midwest ISO generators to become more expensive for external load customers, causing higher-cost generation from within the external areas to be used instead. This would put Midwest ISO generators at a disadvantage, they argue, and would also lead to a decrease interregional trading. In addition, EPSA and Joint Protestors contend that the proposed export charge does not allow investors to recognize the total costs of citing decisions because it does not directly allocate the costs of new transmission.

406. Designated PJM Parties, Exelon and PJM[470] also contend that the proposed MVP export charge would cause the same market distortions that the Commission relied upon as a key basis for eliminating pancaked rates between Midwest ISO and PJM.[471] They argue, therefore, that the proposal is a departure from this precedent and the Commission would need to justify such departure in order to approve the proposal. Designated PJM Parties state that Filing Parties assert without support that there are countervailing benefits that outweigh the identified market problems, but they argue that it is nearly impossible for the Commission to assess the extent to which the proposal could create market distortions, given the sparse record in this proceeding.

407. CPV, EPSA, Joint Protestors, and Midwest Generators also contend that, if approved, the proposed MVP export charge could cause other ISOs and RTOs to adopt similar charges.[472] They state that the Independent Market Monitor found that because

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[469] *See*, *e.g.*, Joint Protestors Comments at 15 (citing *Summary of IMM Comments on Cost Allocation Proposal* (Jun. 10, 2010) (Independent Market Monitor Comments), *available at* http://www.midwestiso.org/publish/Document/345da0_1299503ccb2_-7f5f0a48324a?rev=1).

[470] *See*, *e.g.*, Exelon Comments at 20; PJM Comments at 10-12.

[471] *See*, *e.g.*, PJM Comments at 11 (citing July 23, 2003 Order, 104 FERC ¶ 61,105 at P 28).

[472] CPV Comments at 7-8; EPSA Comments at 8; Joint Protestors Comments at 15; Midwest Generators Comments at 23.

Midwest ISO is a net importer of energy from most areas, end-use customers in Midwest ISO would be harmed far more by neighboring ISOs and RTOs levying an export charge on them than they would benefit from the revenues associated with the proposed export charge.[473] They state that the Independent Market Monitor similarly concluded that the proposed charge would serve as a barrier to full arbitrage between neighboring markets, create inefficiencies in the short-term dispatch of Midwest ISO and its neighbors, and invite neighboring systems to impose similar charges on energy imported into Midwest ISO. EPSA asserts that the seam created by the proposal would deepen if other ISOs and RTOs follow suit, which would be contrary to the Commission's policy of eliminating seams between markets.

408. Joint Protestors argue that the proposal improperly allocates MVP costs to existing customers that entered into long-term transmission agreements based on the knowledge of the costs associated with any transmission upgrades needed to grant the service and, thus, that do not benefit from the MVPs.[474]

iv. <u>Inter-Regional Coordination</u>

409. AEP, Designated PJM Parties, EPSA, Exelon, FirstEnergy, Integrys, and PJM argue that the proposal to assess the MVP usage rate on wheel-through and export transactions either has not been shown to be consistent with or is inconsistent with the Midwest ISO-PJM Joint Operating Agreement.[475] They state that the proposal is an attempt to circumvent the Joint Operating Agreement, which already provides for coordinated system planning between Midwest ISO and PJM, including a determination of which projects qualify for cross-border cost allocation.[476] PJM adds that Filing Parties have not clarified the relationship between the cost allocation for projects under the Joint Operating Agreement versus their proposal, including which cost allocation prevails in the event that a project meets the thresholds for cost sharing under both the MVP proposal and the Joint Operating Agreement. Exelon states that, absent revisions to the

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[473] *See*, *e.g.*, EPSA Comments at 9 (citing Independent Market Monitor Comments at 2; LECG Report at 24).

[474] Joint Protestors Comments at 12-13.

[475] AEP Comments at 4-5; Designated PJM Parties Comments at 13-14; EPSA Comments at 12-13; Exelon Comments at 21-26; FirstEnergy Comments at 43-44; Integrys Comments at 16; PJM Comments at 4-5.

[476] *See*, *e.g.*, AEP Comments at 5 (citing Joint Operating Agreement at sections 9.3-9.4).

Midwest ISO-PJM Joint Operating Agreement, the proposal violates the existing agreement (and, therefore, the Midwest ISO Tariff).

410. Several parties note that Filing Parties have not sought participation from PJM or other RTOs in connection with the development of the process for imposing MVP costs on exports. Exelon argues that, because several of the MVP starter projects are likely to significantly impact the PJM system, Midwest ISO should coordinate with PJM to ensure that they will not cause reliability violations or uneconomic congestion in PJM.

411. Joint Protestors contend that Midwest ISO and PJM should negotiate a cost sharing agreement applicable to load located in states that have enacted renewable portfolio standards.[477] They state that such an agreement would remove the need for the proposed export charge. They maintain that, in instances where a state has taken on the financial burden of self-supplying its own renewable portfolio, load should receive a dollar-for-dollar credit recognizing those costs that would have otherwise been cost shared on a regionalized basis between Midwest ISO and PJM. Joint Protestors add that such an agreement could also address the limitations of the transmission system.[478]

v. OASIS and After-the-Fact Charges

412. EPSA, Joint Protestors, and Midwest Generators contend that the proposed *ex post* rate calculation for the MVP usage rate does not comply with the requirement that transmission providers post on their Open-Access Same-Time Information System (OASIS), on a timely and transparent basis, transmission service prices and associated terms and conditions.[479] They note that under the proposed MVP usage rate, the billing determinants will not be known until after the month's business has closed and, therefore, the MVP usage rate cannot be determined before a customer takes service. EPSA argues that preventing customers from knowing the applicable export charges until potentially a full month after an export occurs is contrary to Commission policy and the public interest.

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[477] Joint Protestors Comments at 20.

[478] Joint Protestors note, for example, that the Michigan Thumb will have limited transfer capability to the other Midwest ISO members after the withdrawal of FirstEnergy in 2011 and that some state renewable portfolio standards must be satisfied with in-state resources. They contend that the agreement could ensure that the associated costs are not simply socialized to all load.

[479] EPSA Comments at 11-12; Joint Protestors Comments at 27-28; Midwest Generators Comments at 21-22.

413. CPV and Midwest Generators contend that assessing the proposed MVP export charge after the fact will cause market distortions for exports because transmission customers will be forced to make dispatch decisions based on their best guess of what after-the-fact MVP charges will be.[480] They state that the proposal does not have similar effects on the dispatch decisions of customers internal to Midwest ISO because load will pay the usage charge regardless of whether they rely on internal or external resources. They add that the after-the-fact posting of prices also disproportionately affects customers that commit to long-term contracts because, over time, customers will have the incentive to rely less on exports and, therefore, the MVP costs will be allocated over fewer MWh.[481]

414. Midwest Generators and CPV disagree with Filing Parties' argument that the proposed export charge is needed to avoid free riders in neighboring regions.[482] They argue that customers using the Midwest ISO transmission network to export power are already assessed point-to-point transmission charges, which ensures that they are allocated the costs of all network upgrades. They argue that the costs of MVPs can be incorporated into the revenue requirement underlying those point-to-point charges, as they are updated routinely to reflect each transmission zone's changing costs, and therefore, a separate MVP charge is unnecessary. Dominion counters that the proposal would actually force non-riders to pay, in violation of the Commission's cost causation principles.

415. Joint Protestors argue that, if the Commission finds that assessing the MVP usage rate on exports and wheel-through transactions is acceptable, Midwest ISO has to propose a rate calculation that will provide market participants with advance notice of the cost of transmission service.[483] Absent a cost sharing agreement between Midwest ISO and PJM, Joint Protestors propose that, in calculating the rates for exports and wheel-through transmission service, the MVP annual revenue requirements should be added to the numerator used in calculating the maximum rates for the current schedule 7 (Firm) and schedule 8 (Non-Firm) Point-To-Point Transmission Service system-wide rate with the transmission owner's current revenue requirements for the existing transmission

[480] CPV Comments at 7; Midwest Generators Comments at 22-23.

[481] Midwest Generators Comments at 22. Midwest Generators also contend that the design of the proposed usage charge conflicts with the Commission's requirements for the development of unit charges for firm transmission services. *See id.* at 21.

[482] *Id.* at 20-21; CPV Comments at 5.

[483] Joint Protestors Comments at 28.

facilities. They contend that this methodology would ensure that the rate is posted in advance, consistent with OASIS requirements, but that the MVP annual revenue requirement would be collected on an after-the-fact basis, consistent with the proposal. They maintain that the total revenue requirements would also be collected based on a transmission customer's reserved capacity. Joint Protestors claim that the charge should be based on reserve capacity, regardless of whether the customer actually schedules energy on a given path.

b. <u>Answers</u>

i. <u>Inter-Regional Benefits</u>

416. In response to comments regarding the benefits MVPs provide to external loads, Filing Parties state that major, integrated facilities, such as MVPs, support all uses of the system, including transmission on the system for delivery to another system. They claim that MVPs that solve reliability issues on the Midwest ISO transmission system do so for all users of the system, regardless of where their ultimate loads are located. They maintain that MVPs that reduce congestion and enhance market efficiency do so for any transmission customers, whether their withdrawal point is inside of the Midwest ISO region or at an interface with an adjacent system. Filing Parties also argue that allocating MVP costs to external loads is consistent with the Commission's repeated findings, upheld by the courts, that the Midwest ISO markets "produce global benefits to those transacting over the Midwest ISO grid" including "a more reliable and efficiently-used transmission grid," "clear price signals for better infrastructure siting," and "price transparency, which benefits even bilateral contract formation."[484] Filing Parties state that exempting grid users whose withdrawal points happen to be at interface points and to assess the associated costs on every other withdrawal point on the system would be unduly discriminatory.

417. Filing Parties argue that the Commission routinely approves export charges for Midwest ISO and numerous other RTOs and that it is a well-accepted rate practice. They note that Midwest ISO assesses charges for export transactions (except at the PJM interface), as does PJM, SPP, New York Independent System Operator, Independent System Operator-New England, and California Independent System Operator. Filing

[484] Filing Parties October 18, 2010 Answer at 48 (citing *Transmission Owners of the Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,339, at P 33, *order on reh'g*, 113 FERC ¶ 61,122 (2005), *aff'd sub nom. E. Kentucky Power Coop., Inc. v. FERC*, 489 F.3d 1299 (D.C. Cir. 2007) (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,235, at P 43, *order on reh'g*, 109 FERC ¶ 61,157 (2004)); *Midwest ISO Transmission Owners*, 373 F.3d at 1369-71).

Parties further assert that, as a general matter, requiring parties to pay for the use of major integrated facilities in a transmission system when they use that system to move power to another transmission provider is just and reasonable. They state that, in Order No. 888, the Commission found that network customers cannot use their network entitlement to make off-system sales and must instead take and pay for point-to-point transmission for that service.[485] They also note that, in Order No. 890, the Commission held that network customers must pay unreserved use penalties if they use their network service to make off-system sales.[486]

418. Filing Parties disagree with commenters that fault the MVP proposal for not including a procedure for PJM to assess on Midwest ISO load a share of the costs associated with PJM transmission expansions that are comparable to MVPs. Filing Parties contend that they are not responsible for making any such filing. They state that the responsibility would instead rest with the public utilities, including the RTO, that would own or operate such facilities.

419. MidAmerican opposes the requests to reduce or eliminate the MVP usage charge applicable to export and wheel-through transactions, arguing that MVPs would benefit external load. It contends that both transaction types would utilize the capacity provided by MVPs because export transactions originate from within and wheel-through transactions pass through the Midwest ISO footprint. MidAmerican also maintains that MVPs would benefit external loads subject to public policy requirements. It adds that, to the extent that external loads purchase energy from resources within Midwest ISO or through the Midwest ISO region, the price of the energy being acquired must be economically beneficial. MidAmerican concludes that allocating MVP costs to external loads would be consistent with the cost-causer and beneficiary-pay principles.

420. In response to Filing Parties' answer, Designated PJM Parties argue that Filing Parties incorrectly presume that all MVPs would benefit external load in the same manner and relative magnitude, no matter where they are located, how they are configured, when they are installed, how they may be loaded or constrained, or how they related to facilities being installed in areas outside of Midwest ISO. Designated PJM Parties submit that Filing Parties' answer confirms that they have no evidentiary support for this assertion. Designated PJM Parties also argue that all of the supportive comments reflect the "unremarkable and unsurprising parochial view" of Midwest ISO participants

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[485] *Id.* at 43 (citing Order No. 888, FERC Stats. & Regs. at 31,751).

[486] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 842).

that they would fare better if loads outside of Midwest ISO share in their transmission upgrade costs.[487]

421. Designated PJM Parties argue that Filing Parties' reference to previously-accepted export charges does not support allocating MVP costs to load in PJM. They state that Filing Parties' statement that "Midwest ISO assesses charges for export transactions (except for PJM interfaces as noted above)" effectively concedes that export charges were unambiguously rejected for transactions between Midwest ISO and PJM.[488] In addition, they argue that Filing Parties cannot reconcile their unilateral attempt to foist charges for internal facility upgrades on external parties with the principles reflected in the Midwest ISO-PJM Joint Operating Agreement or with the Commission's pending Transmission NOPR.[489]

422. Dominion claims that Filing Parties' answer mischaracterizes Dominion's position regarding the MVP proposal.[490] Dominion clarifies that it believes that the proposed MVP rate fails in two respects: first, the rate does not distinguish between MVPs that provide only intra-regional benefits and MVPs that provide both intra- and inter-regional benefits; and, second, the rate would apply to PJM customers for MVPs that would not provide inter-regional benefits. Dominion contends that accepting the proposal's potential market distortions and foisting MVP costs on non-beneficiaries would be an unreasonable solution to an alleged free-rider problem and would violate cost causation principles. Dominion further clarifies that only the subset of MVPs shown to benefit PJM should be allocated to PJM load.

ii. Rate Pancaking

423. Filing Parties argue that the Commission's orders eliminating rate pancaking between Midwest ISO and PJM do not prohibit its proposal to assess the MVP usage rate

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[487] *Id.*

[488] Designated PJM Parties November 2, 1010 Answer at 6 (citing Filing Parties October 18, 2010 Answer at 42).

[489] *Id.* (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 164).

[490] Dominion states that Filing Parties incorrectly include Dominion among commenters alleging that MVP benefits stop at the Midwest ISO-PJM seam and objecting to the recovery of any MVP costs from Midwest ISO transmission customers that serve load outside of Midwest ISO. Dominion November 5, 2010 Answer at 2 (citing Filing Parties October 18, 2010 Answer at 42, 47).

on exports and wheel-through transactions. Filing Parties contend that the Commission's previous orders expressly encourage the broader sharing of the costs of new transmission facilities resulting from the RTO's regional planning process.[491] They also assert that in its previous orders, the Commission addressed whether to require PJM loads to share in the costs of all Midwest ISO transmission, including projects planned by individual transmission owners to meet their local needs, which is distinct from the MVP cost allocation that applies only to new projects that provide broad benefits. Filing Parties state that the MVP proposal does not exempt from MVP charges deliveries to Midwest ISO's interface with PJM because such withdrawals contribute to MVP costs, just like all other withdrawals anywhere else on the Midwest ISO transmission system. They state that, consistent with prior Commission orders, however, rates covering the costs of existing and new (non-MVP) transmission facilities for external transactions sinking in PJM would continue to be discounted to zero.

424. Filing Parties argue that applying the Commission's findings in the orders that eliminated rate pancaking between Midwest ISO and PJM to the MVP proposal ignores the significantly changed circumstances since those orders were issued. They contend that the Commission's directives were based on a perceived irregular seam between Midwest ISO and PJM, which they claim, has since been largely eliminated,[492] and the Commission's expectations of a joint and common energy market between Midwest ISO and PJM, which has not emerged. They argue that the circumstances that warranted an exception to the general rule that allows transmission charges for inter-RTO transactions have materially changed and thus would not support a new extension of that exception to exempt Midwest ISO transmission customers that serve PJM loads from bearing any share of MVP costs.[493]

425. Filing Parties argue that commenters ignore the fact that multiple Midwest ISO charges are assessed on transmission customers serving external load. They note that Schedules 10 and 17 of the Midwest ISO Tariff recover the costs of, among other things,

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[491] Filing Parties October 18, 2010 Answer at 44 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60, May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 22).

[492] Filing Parties submit that, since those orders were issued, Illinois Power decided to remain in Midwest ISO, rather than forming a virtual PJM island surrounded by Midwest ISO transmission owners, and American Transmission System, Inc., which forms an extended Midwest ISO northeastern seam between PJM and Canada, had obtained Commission approval to transfer from Midwest ISO to PJM.

[493] Filing Parties October 18, 2010 Answer at 45.

expansion planning and administering the energy and ancillary services markets from all transmission customers.[494] Filing Parties state that, in the orders approving those schedules, the Commission found it appropriate to impose charges on all transactions on the Midwest ISO transmission system.[495] Filing Parties conclude that MVP benefits are comparable to the regional benefits provided by Midwest ISO itself and, thus, are properly charged to all transmission customers.

426. Filing Parties argue that the MVP proposal is consistent with the Commission's approach of treating Midwest ISO and PJM loads comparably. They state that the Commission has recognized that "all customers have access to the transmission system of the entire [Midwest ISO and PJM] region and can transact freely over that system without paying transactions through-and-out charges," thereby enabling a broad distribution of benefits and making more transactions economic across the Midwest ISO-PJM region.[496] Filing Parties claim that the lack of point-to-point transmission charges between Midwest ISO and PJM shows that PJM loads are even more comparable to Midwest ISO loads, and the MVP proposal treats loads in Midwest ISO and PJM equally for purposes of recovering the costs of new, broadly beneficial transmission projects.

427. In response, Designated PJM Parties argue that Filing Parties mischaracterize the Commission's previous orders that prohibited rate pancaking between Midwest ISO and PJM. Designated PJM Parties claim that, contrary to their initial proposal, Filing Parties concede in their answer that the Commission's prohibition against rate pancaking applies to both existing and new transmission facilities (rather than only to existing ones).[497] Designated PJM Parties maintain that Filing Parties fail to explain why or where the Commission exempted new MVP-type facilities, arguing that the Commission did not carve out MVP or other types of facilities from its prohibition against rate pancaking. Designated PJM Parties also assert that the Commission's directive that the RTOs and

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[494] *Id.* at 45-46 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Schedule 10, section II; *id.* Schedule 17, section II.A).

[495] *Id.* at 46 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,051, at P 24 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,038, at 61,163 (2003); *Midwest ISO Transmission Owners,* 373 F.3d at 1370).

[496] *Id.* (citing May 21, 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85).

[497] Designated PJM Parties November 2, 2010 Answer at 5 (citing Filing Parties July 15, 2010 Filing, Transmittal Letter at 25, n.105; Filing Parties October 18, 2010 Answer at 41).

their transmission owners develop and file a proposal for allocating the costs of new transmission facilities with cross-border benefits did not permit or encourage pancaked rates.

428. Designated PJM Parties argue that Filing Parties' suggestion that the Commission's previous orders eliminating rate pancaking across the Midwest ISO-PJM seam are no longer relevant constitutes a collateral attack on those orders. Designated PJM Parties argue that Filing Parties cannot ignore the Commission's precedent by arguing that circumstances have materially changed via a unilateral filing under section 205 of the FPA. They contend that, at a minimum, Filing Parties carry the burden of establishing that the Commission's existing ratemaking rules are unjust and unreasonable under section 206 of the FPA, and Filing Parties have made no such showing. Designated PJM Parties maintains that the Commission has rejected complaints that were integral parts of similar pleadings because such procedure would provide inadequate notice of the compliance.[498] They also note that the Commission has consistently rejected attempts to attack or evade previous Commission directives in other incidental proceedings.[499] They conclude that the Commission's prohibition of rate pancaking is effective until changed due to findings in a properly-initiated section 206 proceeding.

429. Designated PJM Parties argue that schedules 10 and 17 of the Midwest ISO Tariff fail to support the proposed MVP charges. They explain that schedules 10 and 17 recover Midwest ISO's expenses and have nothing to do with the cost of transmission owners' facilities or the transmission services that they enable. Therefore, they conclude that schedules 10 and 17 provide no support for overriding the Commission's prohibition of transaction-based transmission service charges across the Midwest ISO-PJM seam. They add that schedule 26 explicitly eliminates network upgrade charges on export transactions to PJM, consistent with the Commission's orders.[500]

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[498] *Id.* at 7 (citing *Louisville Power & Light Co.*, 50 FERC ¶ 61,040, at 61,062-63 (1990); *Indiana Michigan Power Co.*, 51 FERC ¶ 61,191, at 61,524 (1990); *Virginia Electric Power Co.*, 53 FERC ¶ 61,047, at 61,167 (1990)).

[499] *Id.* (citing *Pacific Gas and Elec. Co. v. Delta Energy Ctr., LLC*, 116 FERC ¶ 61,004, at P 36 (2006), *reh'g denied*, 116 FERC ¶ 61,207 (2006); *Californians for Renewable Energy, Inc. v. Calpine Energy Servs., L.P.*, 106 FERC ¶ 61,055, at P 10 (2004), *reh'g denied*, 107 FERC ¶ 61,238 (2004); *Dynegy Power Mktg., Inc.*, 101 FERC ¶ 61,369, at P 18 (2002); *El Segundo Power, LLC*, 91 FERC ¶ 61,110, at 61,390-91, *reh'g denied*, 95 FERC ¶ 61,159 (2001)).

[500] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194 (2005) (conditionally accepting cross-border cost allocation for reliability transmission

(continued…)

iii. Market Distortions and Seams Issues

430. In response to commenters' allegations regarding potential adverse market impacts, Filing Parties contend that Midwest ISO commissioned the LECG Report to assess the possible market impacts from various cost allocation approaches. Filing Parties maintain that the LECG Report identified possible impacts from any MVP cost recovery approach, which reflects that rate design "is a matter of judgment, rather than a matter for the slide rule."[501] While Filing Parties concede that the LECG Report concluded that there could be some market impacts from an export charge, they assert that the LECG Report concluded that those impacts could be overcome by spreading the costs among all beneficiaries of MVPs to place external loads in a position comparable to Midwest ISO load. According to Filing Parties, the LECG Report indicated that, otherwise, external loads would enjoy an undue advantage by benefitting from the transmission constructed to support MVPs without having any cost responsibility. Filing Parties state that the LECG Report found that no major problems have resulted from existing Midwest ISO and PJM export charges not scheduled in the day-ahead market. They also submit that the LECG Report stated that export charges can help to avoid disincentives for participation in Midwest ISO markets if load-serving entities could, by withdrawing from Midwest ISO, avoid all transmission investment costs while continuing to receive many of their benefits.[502]

431. In response, Designated PJM Parties contend that the Commission should reject Filing Parties' reliance on the LECG Report regarding the possible market impacts of the proposed export charge. Designated PJM Parties contend that, instead of studying the MVP proposal, the LECG Report studied a prior cost allocation method that would have recovered some MVP-related costs from imports as well as exports.[503] They add that the LECG Report contained a qualitative, rather than quantitative, discussion of possible impacts. Designated PJM Parties conclude that the report is unreliable and cannot be used to assess the extent to which market distortions would exist.

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projects); November 3, 2009 Order, 129 FERC ¶ 61,102 (accepting cross-border cost allocation for economic transmission projects).

[501] Filing Parties October 18, 2010 Answer at 53 (citing *Colorado Interstate Gas*, 324 U.S. at 589).

[502] *Id.* at 53-54 (citing Filing Parties July 15, 2010 Filing, Ramey Test. at 2-3; LECG Report at 40-41).

[503] *Id.* (citing Filing Parties July 15, 2010 Filing, Ramey Test. at 3, 7-8).

iv. Inter-Regional Coordination

432. In their answer, Filing Parties contend that the MVP proposal is not contrary to the Midwest ISO-PJM Joint Operating Agreement. They claim that, although either Midwest ISO or PJM may introduce other projects into Midwest ISO and PJM's coordinated regional planning process, the Joint Operating Agreement explicitly requires joint study only for facilities that respond to specific requests for generator interconnections or for transmission service.[504] Filing Parties contend that this joint study requirement would not apply to MVPs because the proposal specifically excludes Network Upgrades driven solely by interconnection service or transmission service requests.[505] They argue that the Joint Operating Agreement's Coordinated System Planning provisions do not purport to address cost allocation for other types of projects or for projects identified in each RTO's regional plans that provide other types of benefits. Filing Parties maintain that, in a previous proceeding, Midwest ISO and PJM jointly explained that projects designed primarily to allow renewable generation facilities to serve load pursuant to any renewable portfolio standards would likely not qualify as cross-border projects under the Joint Operating Agreement and that each RTO is free to proceed unilaterally with regard to projects that do not strictly meet the Joint Operating Agreement's project classification criteria but involve cross-border benefits.[506] Filing Parties claim that any cost sharing that may be warranted by such cross-border benefits would not be governed by the Joint Operating Agreement.

433. Filing Parties argue that proposed Criteria 1, 2, and 3 differ in several respects from reliability cross border projects and economic cross border projects under the Joint Operating Agreement. They state that several commenters recognize that the Joint Operating Agreement does not address public policy-driven projects under Criterion 1. Filing Parties submit that MVPs under Criterion 2 utilize different benefit measures and threshold benefits-to-cost ratios than economic cross border projects.[507] They also assert

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[504] Filing Parties October 18, 2010 Answer at 49-50 (citing Joint Operating Agreement, sections 9.3.3, 9.3.4).

[505] *Id.* at 50 (citing Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. FF, section II.C.2(f)).

[506] *Id.* at 50-51 (citing Midwest ISO and PJM January 28, 2009 Filing, Docket No. ER05-6-108, *et al.*, at 6).

[507] Filing Parties state that Criterion 2 uses a minimum benefits-to-cost ratio of 1.0, whereas Cross-Border Market Efficiency Projects use 1.25 to 1.0. They add that the benefits measure for Cross Border Market Efficiency Projects is based on adjusted production cost and net load payments, whereas the measure for Criterion 2 considers the

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that MVPs under Criterion 3 address reliability needs and provide widespread economic benefits, while reliability cross border projects include facilities that address reliability needs. They add that the Joint Operating Agreement contains different thresholds for reliability cross border projects and reliability cross border projects than the proposed $20 million or five-percent thresholds for MVPs.[508]

434. Filing Parties maintain that whether the Joint Operating Agreement should be amended to address additional categories of projects would be a matter for future negotiations between the RTOs and their stakeholders. They conclude that nothing prevents the Commission from finding that the broad benefits of MVPs warrant recovering their costs from all grid users whether they serve on-system or off-system loads.

435. In response to Filing Parties' answer regarding the Joint Operating Agreement, Designated PJM Parties contend that Midwest ISO may not unilaterally invent its own cross-border cost allocation. Designated PJM Parties argue that the Commission explicitly required Midwest ISO and PJM to jointly propose the allocation of costs for transmission facilities that produce inter-regional benefits,[509] which resulted in the current Joint Operating Agreement. They argue that, as a result, Midwest ISO and PJM (and their affected transmission owners) must jointly propose the allocation of transmission projects that create inter-regional benefits through the Joint Operating Agreement. They maintain that the statements made in a transmittal letter by Midwest ISO and PJM, as cited by Filing Parties to support that inter-regional cost allocation proposals may be unilateral, are nonsensical, carry no weight, are not part of a filed tariff, and do not override prior Commission orders to the contrary. According to Designated PJM Parties, allowing Midwest ISO to unilaterally propose its own cross-border allocation would allow it to skirt the cost allocation process of the Joint Operating Agreement at anytime.

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reduction of production costs and the associated reduction of prices resulting from transmission congestion relief to be a single type of economic value (i.e., they are not additive). *Id.* at 51, n.152-153 (citing Joint Operating Agreement, section 9.4.3.1.2.1).

[508] *Id.* at 52 (citing Joint Operating Agreement, section 9.4.3.1 and 9.4.3.1.2).

[509] Designated PJM Parties November 2, 2010 Answer at 9 (citing November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60 ("we will require that the RTOs and their transmission owners develop and file within 180 days of the date of this order a proposal for allocating to the customers of each RTO the cost of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO")).

436. Designated PJM Parties contend that MVPs could easily qualify as cross-border projects under the Joint Operating Agreement. They state that the only difference between the proposed MVPs and other cross-border projects under the Joint Operating Agreement is that Filing Parties have proposed a unilateral ability to designate projects as MVPs. They conclude that the MVP proposal is contrary to the Joint Operating Agreement as the mandated vehicle for evaluating the impacts of cross-border projects.

v. <u>OASIS and After-the-Fact Charges</u>

437. Filing Parties submit that the proposed MVP charge does not violate OASIS posting requirements. They maintain that, while the proposed MVP charge recovers transmission revenue requirements, it is not a charge for transmission service. They assert that OASIS posting requirements apply to transmission service customers take pursuant to Schedules 7, 8, and 9 of the Midwest ISO Tariff but the proposed MVP usage charge under Schedule 26-A is merely added to the basic transmission service charge so that the OASIS posting requirements are inapplicable. To the extent that the Commission considers a waiver from the OASIS posting requirements necessary for the proposed MVP charge, however, Filing Parties so request such a waiver. They add that the Commission has granted such waivers in contexts where the posting requirements are deemed incompatible with the service being provided.[510]

438. While Filing Parties argue that the Commission should accept the proposed MVP rate, they state that one alternative to the proposed MVP charge would be a true-up rate that can be posted on OASIS. Filing Parties contend that a true-up rate is not necessarily a better approach, and even if it were, they are only required to submit a just and reasonable approach and are not required to propose the best approach.[511]

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[510] Filing Parties October 18, 2010 Answer at 73 (citing *New York Indep. Sys. Operator, Inc.*, 130 FERC ¶ 61,104, at P 18 (2010); *Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,260, at P 29-30 (2009)).

[511] *Id.* at 72-73 (citing July 6, 2007 Order, 120 FERC ¶ 61,023 at P 45 and n.34, *reh'g denied*, 124 FERC ¶ 61,094 (2008) ("For a proposal to be acceptable, it need not be perfect nor even the most desirable; it need only be reasonable"); Opinion No. 352, 52 FERC at 61,336; *Cities of Bethany*, 727 F.2d at 1136, *cert. denied*, 469 U.S. 917 (utility needs to establish that its proposed rate is reasonable, not that it is superior to alternatives)).

c. Commission Determination

439. We accept the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM. Major integrated facilities such as MVPs support all uses of the system, including transmission on the system that is ultimately used to deliver to an external load. Filing Parties have shown that the MVP proposal would enable projects to improve system reliability, reduce congestion, satisfy documented energy policy mandates or laws, and enhance market efficiency, which would benefit all users of the integrated transmission system, regardless of whether the ultimate point of delivery is to an internal or external load. The proposed criteria ensure that these broad, inter-regional benefits result from MVPs, as we discuss above. We also disagree that Criterion 1 MVPs benefit only Midwest ISO loads that are subject to documented energy policy mandates or laws because Criterion 1 MVPs improve the Midwest ISO transmission system and also permit external entities to use Midwest ISO generation to satisfy external energy policy mandates or laws. We also note that there is no involuntary assignment of costs here given that the MVP usage rate applies to export and wheel-through transactions (i.e., customers that are taking service from Midwest ISO), rather than an external entity taking no service or buying no energy from Midwest ISO, which would not be charged under this proposal).

440. However, we reject the proposed MVP charge for export and wheel-through transactions that sink in PJM. Filing Parties have not shown that their proposal - to assess the MVP usage rate on all exports and wheel-through transactions - does not constitute a resumption of rate pancaking along the Midwest ISO-PJM seam. Such rate pancaking is contrary to the Commission's previous orders eliminating rate pancaking between Midwest ISO and PJM. Specifically, the Commission found that, due to the RTO scope and configuration that resulted from the RTO choices of certain transmission owners now within Midwest ISO and PJM, the continuation of rate pancaking between PJM and Midwest ISO violated Order No. 2000's requirement that RTOs eliminate rate pancaking within a region of appropriate scope and configuration. Accordingly, the Commission found that such pancaked rates constituted unjust and unreasonable rates and required the RTOs to eliminate them.[512] While there have been some changes since the Commission eliminated rate pancaking between Midwest ISO and PJM, we do not find that such changes are sufficient to mitigate the RTO scope and configuration concerns that led the Commission to find that pancaked rates between Midwest ISO and PJM are unjust and unreasonable. Furthermore, to the extent that Filing Parties are arguing that the Commission's decision to eliminate rate pancaking is now incorrect,

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[512] *See, e.g.*, July 23, 2003 Order, 104 FERC ¶ 61,105 at P 35.

making such an argument in this section 205 filing represents an impermissible collateral attack on prior Commission orders.

441. Accordingly, the rate pancaking for transactions between Midwest ISO and PJM that would result from the proposal to charge the MVP usage rate on wheel-through and exports to PJM would conflict with Commission precedent.[513] We therefore reject Filing Parties' proposal as it relates to charges on wheel-through and export transactions to PJM. We require Filing Parties to submit, in the compliance filing due 60 days from the date of this order, tariff revisions to provide that wheel-through and export transactions to PJM are not subject to MVP charges.

442. In addition, while Filing Parties are correct that the Commission directed Midwest ISO, PJM, and their transmission owners to develop a proposal to allocate costs associated with transmission facilities that create cross border benefits, it did not allow them to re-impose the pancaked rates that the Commission had found unjust and unreasonable.[514] Further, Filing Parties have not demonstrated that Midwest ISO's administrative charges under Schedules 10 and 17 are comparable to the proposed MVP charges or that the Commission's approval of those charges would justify a resumption of rate pancaking along the Midwest ISO-PJM seam.

443. We disagree that the proposed MVP charge for export and wheel-through transactions should be rejected due to possible market distortions. While Filing Parties concede that the proposal has the potential to create negative market impacts, such impacts are difficult to predict in advance, and, in any event, there would likely be market distortions associated with any cost allocation methodology that parties propose. For this reason, it has long been recognized that rate design is "not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[515] Many of these market impacts could be overcome by spreading the costs among all beneficiaries of MVPs to place external loads in a position comparable to Midwest ISO load, which is precisely what the proposed charge for export and wheel-through transactions (other than those to PJM) would do. Absent the proposed MVP charge to exports and wheel-through transactions (other than those to PJM), external loads would enjoy an undue advantage by benefiting from the transmission constructed to support MVPs without having any cost responsibility, contrary to cost causation principles. The MVP proposal also avoids

[513] *Id.*

[514] November 18, 2004 Order, 109 FERC ¶ 61,168 at P 60.

[515] *Colorado Interstate Gas*, 324 U.S. at 589.

creating an undesirable incentive for load-serving entities to withdraw from Midwest ISO to avoid paying MVP costs while continuing to receive MVP benefits.[516]

444. Finally, we find that the MVP proposal does not violate the Commission's OASIS posting requirements. The Commission requires transmission providers to "post prices and a summary of the terms and conditions associated with all transmission products offered to transmission customers."[517] This OASIS posting requirement applies to transmission products, such as charges for transmission service under Schedules 7, 8, and 9 of the Midwest ISO Tariff. We find that the MVP proposal does not create a new transmission product, and we agree with Filing Parties that the proposed MVP charge merely recovers transmission revenue requirements.[518] However, we recognize protestors' concerns that advance notice of MVP charges would allow parties to make more sound business decisions, and we encourage Midwest ISO to continue working with its stakeholders to develop mechanisms to provide such advance notice.

4. No Cost Assignment to Grandfathered Agreements

445. Filing Parties state that MVP costs will not be assessed to grandfathered agreements under Schedule 26-A of the Tariff and that this treatment is similar to the treatment of grandfathered agreements under Schedule 26, which governs the recovery of the costs of network upgrades that are determined under Attachment FF to be subject to Attachment GG, the latter of which is used to calculate charges for Baseline Reliability Projects and Market Efficiency Projects.[519]

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[516] Filing Parties July 15, 2010 Filing, Ramey Test. at 2-3.

[517] 18 C.F.R. § 37.6(c)(1) (2010) (emphasis added).

[518] Therefore, Filing Parties' request for waiver of these requirements is moot.

[519] Filing Parties July 15, 2010 Filing, Transmittal Letter at 26. *See also* the definition of grandfathered agreement(s) in the Midwest ISO Tariff:

> An agreement or agreements executed or committed to prior to September 16, 1998 or [Independent Transmission Company] [g]randfathered [a]greements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section 1.276.

a. Comments

446. Minnesota Commission-Minnesota Security ask the Commission to order Filing Parties to revise their filing to not exempt loads under grandfathered agreements from sharing in MVP costs.[520] They note that grandfathered agreements are held by some, but not all, of Midwest ISO's transmission owners, and they argue that the impacts of not allocating costs to load under grandfathered agreements may be more significant for those transmission-owning utilities holding grandfathered agreements because any costs not charged to grandfathered agreement customers are unfairly borne by the remainder of the customers. Minnesota Commission-Minnesota Security also assert that most grandfathered agreements are many years old and rely on the historically existing transmission system to supply the power under the terms of the grandfathered agreements. However, states Minnesota Commission-Minnesota Security, Midwest ISO's studies show that MVPs would provide measurable benefits to all customers in the Midwest ISO footprint, including grandfathered agreement customers. Minnesota Commission-Minnesota Security also point to the Transmission NOPR, which they believe addresses this issue when the Transmission NOPR cited a District of Columbia Circuit Court case and concluded, "[a]fter stating that the subject costs were the administrative costs of having an ISO, the D.C. Circuit found that the Commission correctly determined that bundled and grandfathered loads should share the costs of having an ISO because they drew benefits from Midwest ISO."[521] Minnesota Commission-Minnesota Security state that, since grandfathered agreement loads are included in the required metrics and thresholds studies, grandfathered agreement loads benefit to the same extent as other loads and should, according to the basic premise of the Commission's Transmission NOPR and the courts, share in the costs of the projects from which they benefit.

447. NIPSCO asserts that charges for facilities built to meet public policy requirements should apply to grandfathered agreements to the extent that those public policy requirements apply to entities subject to grandfathered agreements. Moreover, if an entity with load under a grandfathered agreement builds an MVP and receives revenues from other Midwest ISO load, fairness requires that the entity pay charges for MVPs built by others in Midwest ISO.[522]

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[520] Minnesota Commission-Minnesota Security Comments at 6.

[521] *Id.* (citing Transmission NOPR, FERC Stats. & Regs. ¶ 32,660 at P 146).

[522] NIPSCO Comments at 7.

b. **Answers**

448. Filing Parties answer that this issue would be better addressed in a separate proceeding, where the grandfathered agreement exemption for both Schedules 26 and 26-A could be considered, and the matter could receive the attention that it deserves, rather than trying to resolve it as a subset of the many issues already presented in this proceeding.[523]

449. Michigan Agencies reply that they each are a party to certain carved-out grandfathered agreements.[524] These parties state that it is highly disturbing for Midwest ISO to suggest that this is an issue that deserves attention, rather than making clear that the policy of carved-out grandfathered agreements has been established for years (since Midwest ISO launched its Day 2 energy markets), that the amount of load served by such grandfathered agreements has decreased and will continue to decrease as the various grandfathered agreements expire by their own terms, and that Midwest ISO's own reports to the Commission on grandfathered agreements have consistently concluded that grandfathered agreements are not disrupting the Midwest ISO markets. Finally, Michigan Agencies state that arguments that they benefit from the system no differently than non- grandfathered agreements transactions are old and untrue arguments.[525]

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[523] Filing Parties October 18, 2010 Answer at 26, n.85.

[524] *See* the definition of carved-out grandfathered agreement(s) in the Midwest ISO Tariff:

> Any [g]randfathered [a]greement(s) that the Commission has identified as "carved out" pursuant to Appendix B of the Commission's September 16, 2004 order, *Midwest* [*Indep.*] *Transmission* [*Sys.*] *Operator*, *Inc.*, 108 FERC ¶ 61,236 (2004) or that meet the criteria in [s]ection 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section 1.68.

[525] Michigan Agencies November 1, 2010 Answer at 2, 3.

c. **Commission Determination**

450. We will accept the proposal to exclude grandfathered agreements from the regional allocation of MVP costs under Schedule 26-A. We find that this treatment is consistent with the existing exclusion of grandfathered agreements from the regional allocation of the costs of other network upgrades under Schedule 26.

451. Consistent with our finding elsewhere in this order, we agree with the general notion that MVPs benefit parties under grandfathered agreements. However, we disagree with the conclusion that customers to grandfathered agreements would benefit without an associated contribution to MVP costs. Grandfathered agreements predate the existence of Midwest ISO, and thus, the rate design for service under such agreements does not reflect the regional rate design and cost allocation that applies to service taken under the Tariff (i.e., to agreements that are not grandfathered). Instead, each transmission owner recovers the costs of the transmission facilities used to provide service to grandfathered agreements (including any Baseline Reliability Projects, Market Efficiency Projects, and MVPs on its system) directly from the customer under the grandfathered agreement, and each grandfathered agreement customer pays separate charges to each transmission owner from whom it takes grandfathered service (i.e., a pre-RTO pancaked rate design).[526]

452. We also note that the divisor of the network upgrade charge in Attachment GG includes the contract demand of grandfathered agreements that reflect a pancaked rate design and thus reflects an allocation of the cost of Baseline Reliability Projects and Market Efficiency Projects to grandfathered service agreements.[527] Similarly, we find that, in its compliance filing due 60 days from the date of this order, Midwest ISO must clarify that the divisor of the MVP usage charge in Attachment MM in fact reflects the MWhs of grandfathered service provided by each transmission owner to reflect an allocation of the costs of MVPs recovered under grandfathered agreements.

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[526] *See Midwest Indep. Transmission Sys. Operator, Inc., et al.*, Opinion No. 453, 97 FERC ¶ 61,033, at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners, et al. v. FERC*, No. 02-1121, *et al*. (D.C. Cir. 2004).

[527] *See* Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, Att. GG, section 2.d (the network upgrade charge divisor is the same divisor used in Attachment O of the Tariff and in footnote S to the General Rate Formula Template under Attachment O of the Tariff).

E. Exiting and Entering Transmission Owners

453. Filing Parties propose that a Transmission Owner that withdraws from Midwest ISO will remain responsible for all financial obligations incurred under Attachment FF while a member of Midwest ISO.[528]

1. Comments

454. Several parties[529] protest the seemingly contradictory language in the proposal regarding if and how withdrawing Transmission Owners will be charged for MVP costs. Duke states that while MVP cost allocation is based on usage over time according to Midwest ISO, the Curran testimony states that "as the entities that use and benefit from MVPs change over time, the MVP cost allocation method properly assigns the appropriate level of costs to those users."[530] Duke states that this means that MVP cost allocation is based on megawatt hours of actual usage of the transmission system, rather than actual or forecast peak load. However, Duke points to a later statement in Curran's testimony, which states that "Transmission Owners that withdraw from the Midwest ISO will be obligated to pay for the remaining MVP costs allocated to load served by the Transmission Owner if the MVP is approved prior to the effective date the Transmission

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[528] *See* Filing Parties July 15, 2010 Filing at Tab C, Midwest ISO, FERC Electric Tariff, Att. FF, First Revised Sheet No. 3840. Midwest ISO proposes the following change: "A ~~Party~~ Transmission Owner that withdraws from the Midwest ISO as a Transmission Owner shall remain responsible for all financial obligations incurred pursuant to this Attachment FF while a Member of the Midwest ISO and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing Member."

Party(ies) is currently defined as "The Transmission Provider, [Independent Transmission Company] where appropriate, Market Participants, Transmission Customers and Transmission Customers, or any combination of the above." Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, First Revised Sheet No. 240.

[529] AMP, ATC, Duke, FirstEnergy, Illinois Commission, and PJM.

[530] Duke Comments at 1 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 10).

Owner withdraws from the Midwest ISO, but after the Transmission Owner becomes a member of the Midwest ISO."[531]

455. Duke seeks clarification on this issue, asserting that nothing in the proposed Tariff language supports Curran's statement. In the alternative, if Duke's interpretation of the proposed language is deemed incorrect and Duke will be financially responsible for MVP cost allocation after leaving Midwest ISO, Duke states that this is unduly discriminatory. Duke states that it is unduly discriminatory to charge an entity that leaves Midwest ISO based upon its historic demand or historic usage of the transmission system, while charging others based on their current use of the system.[532]

456. FirstEnergy states that under no circumstances should Midwest ISO allocate MVP costs to ATSI or the ATSI utilities.[533] ATSI and the ATSI utilities are withdrawing from Midwest ISO and will be fully integrated into PJM on June 1, 2011.[534] FirstEnergy states that, although MVP costs will be recovered through a usage charge, Midwest ISO proposes an effective date for this proposal of July 16, 2010, in what FirstEnergy views as an attempt to obtain approval of MVPs. Further, FirstEnergy states that even if the MVP proposal, as written, permitted Midwest ISO to charge ATSI, as a withdrawing Transmission Owner, for MVP costs, Midwest ISO is precluded from modifying the rights and obligations of a withdrawing Transmission Owner by means of an FPA section 205 filing.[535]

457. As a primary matter, FirstEnergy notes that under the Midwest ISO Tariff for both Baseline Reliability Projects and Market Efficiency Projects, costs are allocated to

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[531] *Id.* at 3 (citing Filing Parties July 15, 2010 Filing, Curran Test. at 40); *see also* AMP Comments at 18-19; ATC Comments at 9-10.

[532] Duke Comments at 4. Minnesota Commission-Minnesota Security contend that transmission owners leaving Midwest ISO pay for studies pertaining to reliability, interconnection, operations, and markets, but they do not pay the full administrative and study costs of leaving. Minnesota Commission-Minnesota Security recommend that the Commission order Midwest ISO to work with its members to revise the procedures for leaving Midwest ISO to obligate a member to pay the full cost involved. Minnesota Commission-Minnesota Security Comments at 7.

[533] FirstEnergy Comments at 21.

[534] *Id*. at 2.

[535] *Id*. at 21.

Transmission Customers only, and under the Midwest ISO Tariff, a Transmission Owner is not a Transmission Customer. Further, the responsibilities of a withdrawing party extend only to Parties, and Transmission Owner is not included in the definition of Party(ies).[536] FirstEnergy cites as evidence of Midwest ISO's intention to allocate costs to ATSI and the ATSI Utilities, Midwest ISO's inclusion of their load in its study of the Michigan Thumb Project as an MVP, assigning ATSI approximately 11.5 percent of the cost.[537] FirstEnergy states that Midwest ISO has not shown that its apparent intent to allocate MVP costs to load in the ATSI zone and require ATSI to pay such costs upon withdrawal is fair, reasonable, and "roughly commensurate" with the benefits to load in the ATSI zone.[538] Finally, FirstEnergy argues that further proof that Midwest ISO has no justification for allocating costs to ATSI upon its withdrawal from Midwest ISO, are ATSI's timely actions taken to join PJM[539] and the fact that Midwest ISO removed the ATSI zone from Midwest ISO in its transmission planning models in analyzing the Michigan Thumb Project.

458. Duke and FirstEnergy cite the Commission's findings upon Duquesne Light Company's request to leave PJM. In that case, the Commission determined that Duquesne could not avoid paying for capacity that PJM had already acquired on its behalf, but that, because Duquesne's withdrawal plan was otherwise acceptable and absent reliance concerns, it was appropriate to honor Duquesne's request to be excluded

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[536] *Id*. at 24-25 (citing Midwest ISO, FERC Electric Tariff, Fourth Revised Vol. No. 1, section II.1.494, First Revised Sheet No. 240). The Midwest ISO Tariff reads, "Party(ies): The Transmission Provider, [Independent Transmission Company] where appropriate, Market Participants, Transmission Customers and Transmission Customers, or any combination of the above."

[537] *Id*. at 28.

[538] *Id*. at 34 (citing *Illinois Commerce Commission*, 576 F.3d at 476).

[539] These include: i) commitment of the ATSI utilities' respective loads into the PJM capacity auctions for the 2013-2014 planning year; ii) conducting auctions for procuring all of the PJM-qualified capacity necessary to meet the ATSI zone's capacity obligations for the 2011-2012 and 2012-2013 delivery years and executing the related, legally-binding bilateral unit-specific capacity purchase and sale agreements with the capacity resources that cleared in each auction obligating them to pay a total of nearly $600 million for the capacity procured through the auctions; and iii) participating in PJM's RTEP planning process. *Id.* at 36.

from the May 2008 auction, for which PJM had not yet published its parameters.[540] The Commission found that Duquesne would no longer be required to pay PJM's regional transmission expansion planning costs upon its departure from PJM. The Commission determined that the PJM tariff requires PJM to allocate RTEP costs based upon load-ratio share, and that PJM was required by its tariff to recalculate load-ratio share on an annual basis "to reflect PJM's then-existing zones and loads."[541] FirstEnergy states that Midwest ISO has no authority to impose such significant additional financial burdens on the Midwest ISO transmission owners, that Midwest ISO offers no justification for the proposed revision, and that this change is unrelated to, and unnecessary to implement, the MVP. FirstEnergy, further, states that nowhere does the Transmission Owners Agreement provide for or authorize Midwest ISO unilaterally to create significant, new financial obligations. Thus, FirstEnergy recommends that the Commission reject the proposed change.[542]

459. AMP states that Midwest ISO proposes to continue to charge Transmission Owners for the full value of MVP approved while the Transmission Owners are members, even after they withdraw from Midwest ISO. This fails to allocate responsibility equitably, according to AMP.[543] AMP believes that Midwest ISO's proposal should be revised such that if an existing Transmission Owner departs from Midwest ISO, then customers within the relevant transmission zone should not be charged the MVP usage rate, which would more accurately reflect usage of the relevant MVP facilities.[544] AMP also describes a case where a Transmission Owner withdraws from Midwest ISO, but the load in the relevant Transmission Owner's zone has a resource that remains within Midwest ISO. In such an instance, AMP states, Midwest ISO would impermissibly double charge both the MVP rate and the export charge. AMP requests that the Commission, at a minimum, require Midwest ISO to ensure that no

[540] *Id.* at 32 (citing *Duquesne Light Co.*, 122 FERC ¶ 61,039, at P 96 (2008), *order on reh'g*, 124 FERC ¶ 61,219 (2009) (September 3, 2008 Order), *reh'g pending*).

[541] Duke Comments at 4-5 (citing September 3, 2008 Order, 124 FERC ¶ 61,219 at P 162-177).

[542] FirstEnergy Comments at 28-29.

[543] AMP Comments at 18-19.

[544] *Id*. at 19.

double charge occurs, and preferably eliminate both the export charge and the withdrawal charge.[545]

460. Illinois Commission recommends that the Commission direct Midwest ISO to clarify its position regarding changing transmission system use and changing MVP use over time and to clarify its MVP rate design proposal.[546] PJM presents arguments similar to FirstEnergy and others, that Transmission Owners that withdraw from Midwest ISO cannot be allocated costs for MVP transmission projects when the MVP category did not exist when those Transmission Owners made their decision to withdraw. PJM cites ATSI, which received Commission approval on December 17, 2009, to withdraw from Midwest ISO and join PJM in 2011.[547] PJM also seeks clarification of the proposal to charge withdrawing Transmission Owners for MVP costs since the MVP usage rate is based on actual usage. PJM states that Midwest ISO has provided no explanation of how such a charge will be calculated for a Transmission Owner that is no longer a member of Midwest ISO.[548]

461. ATC and FirstEnergy also object to the proposed revision to Original Sheet No. 3480 of Attachment FF proposed by Midwest ISO as unclear regarding the purpose and meaning of the proposed change. ATC states that all parties, whether Transmission Owners, Transmission Customers, or any other party, must fulfill their financial obligations upon withdrawal from Midwest ISO. If there are no financial obligations in the first instance, ATC states, the proposed language does nothing more than reduce the range of current members that may have financial obligations to Midwest ISO and its remaining Transmission Owners. ATC recommends that the Commission reject this proposed change.[549]

462. Finally, NextEra expresses concern that Transmission Owners may base their decisions to withdraw from an RTO on short-term economic concerns rather than a long-

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[545] *Id*. at 19-20.

[546] Illinois Commission Comments at 53.

[547] PJM Comments at 13.

[548] *Id*. at 14.

[549] ATC Comments at 9-10.

term view. NextEra urges the Commission to give the utmost scrutiny to any withdrawal proposals and to not approve a withdrawal unless it is found to be just and reasonable.[550]

2. Answers

463. In response to protestor comments in regard to withdrawing load-serving entities, as a first matter, Filing Parties contend that these issues are beyond the scope of this proceeding. Regarding objections to the proposed change in Attachment FF, Filing Parties state that changing the word "party" to "Transmission Owner" is consistent with the terminology and intent of the Transmission Owners Agreement, and clarifies that the provision covers withdrawal "as a Transmission Owner." They contend that the substance of the provision, which the Commission has been previously accepted as just and reasonable, cannot be collaterally attacked in this proceeding. Filing Parties note that the Transmission Owners Agreement expressly provides that "All financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing Owner."[551]

464. As to the argument that a withdrawing load-serving entity should not be held liable for any transmission cost allocation from a transmission project approved after the load-serving entity has announced its intent to withdraw, Filing Parties state that this was not the cut-off point established in the *ATSI* withdrawal case, in which the Commission allowed ATSI to be charged for the cost of projects planned and approved before the actual withdrawal date.[552]

465. In response to AMP's argument that the Commission should require Midwest ISO to ensure that no double charging occurs, Filing Parties state that as in the case of any other Transmission Owner withdrawal, it is expected that any credits due to the withdrawing Transmission Owner would offset any of its obligations. Thus, the MVP proposal would not involve any double-billing of withdrawing Transmission Owners.

466. In answer to FirstEnergy's argument regarding the obligations of its affiliated utilities when they leave Midwest ISO and join PJM, ITC Companies state that such

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[550] NextEra Comments at 24-25.

[551] Filing Parties October 18, 2010 Answer at 74 (citing Transmission Owners Agreement, Article Five, section II.B ("Existing Obligations")).

[552] *Id*. at 76-77 (citing *Am. Transmission Sys., Inc. v. PJM Interconnection, LLC*, 129 FERC ¶ 61,249, at P 112-14 in relation to P 94-95, 98 (2009) (*ATSI*)).

issues should be addressed in a separate proceeding, based on the Tariff language approved by the Commission in the instant proceeding.[553]

467. ITC Companies also object to the change to Attachment FF proposed by Midwest ISO. They state that the language as it currently exists has served to address the responsibilities of load in the zone of an existing Midwest ISO member for obligations that arise under Attachment FF, and they recommend that the Commission reject the proposed change. If it is accepted, ITC Companies recommend that the Commission order that it not apply to Independent Transmission Companies, because these companies have no load.[554]

468. AMP and FirstEnergy object to Filing Parties' description of the proposed change in Attachment FF as insubstantial or cosmetic. Because the terms Party and Transmission Owner have different meanings, AMP argues, the change is material, and Filing Parties' argument that this line of questioning is a collateral attack on the Tariff is misplaced.[555] Regarding the issue of double-charging, AMP contends that Filing Parties' answer to their concern is meaningless. AMP states that the issue at hand is whether an embedded load-serving entity with a non-migrating resource will be double-charged. That is, would happen if the embedded load-serving entity were made to pay both: 1) a load ratio or other share of MVP-related costs assigned to ATSI, and 2) in addition, MVP-related costs included in Midwest ISO's proposed export charge for the transmission from Midwest ISO to PJM of energy from a non-migrating resource.[556]

469. FirstEnergy states that the proposed change would result in a very significant cost shift from Parties, as defined in the Tariff, to Transmission Owners. It states that under the existing Tariff, costs of MTEP projects are allocated under Attachment FF to loads in Midwest ISO pricing zones and that Transmission Owners are not subject to charges under Attachment FF. It challenges Filing Parties' reliance on the Transmission Owners Agreement as authority for the proposed change, arguing that while the withdrawal language in Attachment FF may be "based on" Article V, section II.B of the Transmission Owners Agreement, Attachment FF does not impose financial obligations on Transmission Owners. Further, the Commission orders cited by Filing Parties as

[553] ITC Companies September 27, 2010 Answer at 4.

[554] ITC Companies September 27, 2010 Answer at 13-14.

[555] AMP November 2, 2010 Answer at 4-5.

[556] *Id*. at 12.

authorizing or justifying the imposition of MVP costs on withdrawing Transmission Owners is misplaced; it states that the two orders both arose in the context of Midwest ISO seeking to ensure recovery of costs that it incurred upon start-up, without which Midwest ISO's financial viability would have been jeopardized.[557]

3. <u>Commission Determination</u>

470. The parties raise three distinct issues. First, regarding whether Filing Parties' proposed changes to Attachment FF are just and reasonable, we find that they are just and reasonable, and, further, are consistent with the language of the Transmission Owners Agreement. We reject the argument that the purpose of the proposed changes is unclear. The Transmission Owners Agreement defines the financial obligations that withdrawing transmission owners face.[558] The proposed changes seek to remove ambiguity about the applicability of such obligations to transmission owners and simply brings the Tariff into agreement with the above language.

471. The second issue at hand is whether load that withdraws from Midwest ISO is subject to the MVP usage rate charge for MVPs. As we read the proposal, a transmission owner that withdraws from Midwest ISO would remain responsible for all financial obligations incurred with respect to the MVP Tariff provisions while a member of Midwest ISO. Such amounts would be determined at the time of the withdrawal. We accept Filing Parties' statement that the withdrawing Transmission Owner would receive credits against any MVP usage charges incurred after it withdraws, to the extent necessary to avoid the possibility of withdrawing Transmission Owners being subject to double billing. In addition, a transmission owner that withdraws from Midwest ISO and joins PJM would not be subject to the MVP usage charge for subsequent exports from Midwest ISO to serve its load in PJM. To the extent that such withdrawing transmission owner is subject to an exit fee reflecting MVP costs allocated to its zonal load, the exit fee would not constitute rate pancaking, because the charge would not be transactional,

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[557] FirstEnergy November 2, 2010 Answer at 4-7 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 101 FERC ¶ 61,221, at P 10 (2002); *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,035, at P 2 (2003)).

[558] *See* Transmission Owners Agreement, Art. V, sec. B (Existing Obligations), ("All financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Midwest ISO and the withdrawing owner."); *see also*, March 17, 2006 Order, 114 FERC ¶ 61,282 at P 52-60, *order on reh'g*, 116 FERC ¶ 61,020 (2006) (accepting an exit fee that was submitted pursuant to Article V of the Transmission Owners Agreement).

but would be assessed regardless of where power is sourced to serve that load (from within PJM or imported from Midwest ISO).

472. Third, as to the process of withdrawal and other costs that a particular withdrawing member may face, we find that these issues are beyond the scope of the instant proposal. Such determinations should be made at the time an application to withdraw is made, with the appropriate notice and opportunity for comments.

F. Joint Ownership and Eligibility for Regional Cost Sharing

473. Under Filing Parties' proposed revisions to Attachment FF, a new transmission owner's pre-existing planned transmission projects, pending at the time it joins Midwest ISO, will not be subject to regional cost sharing under the Tariff.

1. Comments

474. Midwest TDUs argue that the proposal should be revised to accommodate Joint Ownership Arrangements. Midwest TDUs contend that the proposed language does not clarify whether a jointly-owned project can qualify as an MVP (or a Baseline Reliability Project or a Market Efficiency Project) if it is owned, in part, by transmission-dependent utilities that are not currently a transmission-owning member of Midwest ISO or that do not apply to be a transmission-owning members until the project is constructed. Midwest TDUs maintain that it would be unduly discriminatory and contrary to the Commission's objectives to facilitate transmission expansion if the proposal limits the potential pool of MVP owners to include only existing transmission-owning members of Midwest ISO. Midwest TDUs argue that joint ownership arrangements galvanize broad support for projects and should be facilitated to assist with the siting and construction of MVPs. Midwest TDUs ask that Filing Parties should be required to clarify or revise this language to avoid increasing barriers to joint ownership arrangements.

2. Answers

475. Filings Parties answer that they oppose allowing new Midwest ISO transmission owners to receive regional cost sharing for their portion of pre-existing, jointly-owned projects that were planned before their integration as transmission-owning members. They contend that this is an established practice and is not a change from existing policy and practice. They argue that the Commission has made clear that a prospective transmission owner's pre-existing planned transmission projects, pending at the time when it joins Midwest ISO, are not subject to regional cost sharing under the Midwest ISO Tariff.[559] Filing Parties support this policy because such pre-existing projects would

[559] Filing Parties state that the Commission applied this policy to the recent

(continued…)

not have been planned under the Midwest ISO regional planning process and new Midwest ISO transmission owners would not be assigned costs for regional projects submitted to the Midwest ISO Board prior to their integration. Filing Parties oppose granting Midwest TDUs an exception for the purposes of jointly-owned projects because an entity should enjoy the benefits of being a Midwest ISO transmission owner (e.g., regional cost sharing for some of its facilities) only when it accedes to the many responsibilities of that status (e.g., ceding operational control over its transmission and mandatory participation in the MTEP process). They state that the Commission has been skeptical of past proposals to create special rules to allow entities to receive the benefits of Midwest ISO participation while escaping some of the costs,[560] and the Commission should apply similar skepticism here.

476. Midwest TDUs respond that Filing Parties' position is a clear departure from prior practice. They state that, in 2008, Midwest ISO repeatedly confirmed that the joint ownership shares of Midwest TDUs in the CapX 2020 projects would be eligible for regional cost sharing on the same basis as existing Midwest ISO transmission owners.[561] Midwest TDUs contend that they seek to maintain the status quo and to require Midwest ISO to stand by the assurances that it has provided to WPPI and MRES. Further, they assert that limiting cost allocation to the pricing zone where the facility is located would discourage joint ownership in projects.

3. <u>Commission Determination</u>

477. We deny Midwest TDUs' request to require Filing Parties to revise the MVP proposal to further accommodate Joint Ownership Arrangements because this request is outside of the scope of this proceeding. Concerns about which projects of a new transmission-owning member will be subject to the Midwest ISO regional planning process and which of its transmission projects will be subject to cost allocation pursuant to Attachment FF should be raised when a prospective Transmission Owner applies to

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integrations of MidAmerican and Dairyland as Midwest ISO transmission owners. Filing Parties October 18, 2010 Answer at 82 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 128 FERC ¶ 61,046, at P 61 (2009); *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,187, at P 14 (2010) (May 28, 2010 Order)).

[560] *Id.* at 84 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 126 FERC ¶ 61,139, at P 66-71 (2009)).

[561] Midwest TDUs November 2, 2010 Answer at 3-8 (citing telephone and email discussion between representatives of Midwest ISO and representatives of WPPI and MRES).

join Midwest ISO.[562] Insofar as Midwest TDUs seek compensation for facilities prior to becoming a transmission-owning member and transferring control of such facilities to Midwest ISO, that request is beyond the scope of this proceeding.

G. **Effective Date**

478. As noted above, Filing Parties request waiver of the prior notice requirement to permit the proposed Tariff revisions in the July 15 Filing to become effective on July 16, 2010. They state that such an effective date is necessary and appropriate to provide guidance and certainty in connection with pending public policy-driven transmission project proposals and with respect to the generator interconnection process. According to Filing Parties, the July 16, 2010 effective date was selected to apply MVP cost allocation for transmission projects that may be approved in Appendix A of the 2010 MTEP. They state that this effective date would allow Midwest ISO to apply the MVP criteria to those projects eligible for approval in the 2010 MTEP and report the projects that are eligible for the MVP cost allocation methodology to the Midwest ISO Board for approval in December 2010.[563] They also claim that it is consistent with the Commission's directive in the October 23, 2009 Order to adopt subsequent Tariff revisions by July 15, 2010, and given that directive, stakeholders have been on notice that changes in the Midwest ISO cost allocation methodology were forthcoming.[564]

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[562] *See* May 28, 2010 Order, 131 FERC ¶ 61,187 at P 14 (explaining that when projects will be subject to the Midwest ISO regional planning process and which transmission projects will be subject to cost allocation pursuant to Attachment FF is an issue associated with the integration of any new transmission-owning member into the Midwest ISO regional planning process).

[563] The Commission notes that on December 2, 2010, the Midwest ISO Board voted on MTEP 2010.

[564] Filing Parties July 15, 2010 Filing, Transmittal Letter at 40.

1. Comments

479. Several parties oppose a July 16, 2010, effective date.[565] Some argue that Filing Parties have not shown good cause for waiver of the prior notice requirement, because: 1) the potential consequences of not obtaining waiver of notice that are cited by Filing Parties are speculative; 2) the request for waiver does not address the impact that a waiver of notice would have on customers, as required by section 35.11 of the Commission's regulations; 3) under Commission precedent, waiver of notice is denied where rate increases or the effective date are not prescribed by agreement or contract; and 4) Filing Parties do not cite to an emergency such as the unanticipated consequences affecting Otter Tail and Montana-Dakota Utilities when Filing Parties sought approval of the interim cost allocation methodology.

480. In addition, commenters argue that: 1) the proposed effective date does not afford stakeholders a sufficient opportunity to review and propose alteratives to the proposal;[566] and 2) the proposed effective date would allow the proposed allocation to apply to the FirstEnergy and Duke zones prior to their withdrawal from Midwest ISO, and their customers would become financially responsible for those transmission upgrades with no corresponding benefits.

481. Indiana Commission and NIPSCO argue that a July 16, 2010, effective date would mean that no other market participant or other entity would have the opportunity to propose alternatives to the fast-tracked project approved by the Midwest ISO Board. Therefore, NIPSCO states, the planning process for MVPs should start at the beginning of the Midwest ISO planning process. NIPSCO suggests that the Commission make the effective date of the MVP cost allocation methodology the same as the date Midwest ISO begins the next MTEP process.

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[565] *See* AMP Comments at 12-13; FirstEnergy Comments at 46-54; Illinois Commission Comments at 54-56 (opposing requested effective date with respect to the MVP cost allocation proposal); Indiana OUCC Comments at 4; Indiana Commission Comments at 4; Minnesota Commission-Minnesota Security Comments at 5-6; NIPSCO Comments at 8-9; OCC Comments at 11-14; MICH-CARE Comments at 8.

[566] For example, Indiana Commission and NIPSCO argue that a July 16, 2010 effective date would mean that no other market participant or other entity would have the opportunity to propose alternatives to the fast-tracked project approved by the Midwest ISO Board. Therefore, NIPSCO states, the planning process for MVPs should start at the beginning of the Midwest ISO planning process.

482. OCC and FirstEnergy argue that the proposed cost allocation methodology that would result from the 19-month stakeholder process has been a work in progress and has constantly shifted throughout the process and that the instant proposal is very different from what stakeholders were originally presented to consider. OCC urges the Commission not to set an effective date until stakeholders have had sufficient time to comment both on the proposed cost allocation methodology and on projects that may qualify as MVPs and whose costs may be charged to them. FirstEnergy argues that the process was never approved by the RECB Task Force or the OMS CARP, and that it was not the approach that the Midwest ISO Advisory Committee preferred. FirstEnergy argues that the proposal should be rejected so that stakeholders can have an opportunity to fully evaluate it. FirstEnergy asks the Commission to confirm that Midwest ISO is not, and will not be, authorized to consider and approve MVPs until the Commission accepts and makes effective the Tariff revisions proposed in this proceeding.

483. Indiana OUCC expresses conditional support for the overall Midwest ISO approach contingent upon, among things, that the effective date should be postponed to allow parties which have not been deeply involved in the review of already-proposed projects to have ample time to do so. Several parties request that the Commission suspend Filing Parties' filing and set it for hearing.[567] For example, ABATE, Industrial Customers and MISO Northeast Transmission Customers argue that the MVP cost allocation methodology proposal raises numerous factual issues that require discovery and an evidentiary hearing.

484. Opponents of a July 16, 2010 effective date argue for various alternative effective dates: 1) 60 days from the date of filing; 2) after five months suspension; 3) no earlier than the date the Commission accepts the proposal; 4) no earlier than December 2011, to coincide with the time when the 2011 MTEP can be approved by the Midwest ISO Board; and 5) after the Commission establishes standards for MVPs in the Transmission NOPR proceeding.

485. In addition, Minnesota Commission-Minnesota Security argue that the multi-billion dollar CapX 2020 transmission upgrade proposal benefits neighboring states, relieves congestion and assists in fulfilling Minnesota's renewable energy mandate but is arbitrarily excluded from MVP status because any projects approved by the Midwest ISO Board before July 15, 2010 will be treated as existing lines under Midwest ISO's prior RECB cost allocation method. Minnesota Commission-Minnesota Security urge the

[567] ABATE Comments at 5; FirstEnergy Comments at 49-50; Illinois Commission Comments at 55; Industrial Customers at 45; MISO Northeast Transmission Customers Comments at 34; Hoosier-SIPC Comments at 23-24.

Commission to order Midwest ISO to allow the CapX 2020 projects that have been approved but have not yet commenced construction to apply for MVP status so that they could become eligible as MVPs for cost sharing under the cost allocation and rate design methods ultimately approved by the Commission.

486. IPL requests that, if the Commission moves forward with the instant proposal, and if it finds IPL's proposals for modifying the proposal to be promising but is not prepared to direct that the proposal incorporate such features in a compliance filing, then the Commission should establish settlement judge procedures as a way to resolve remaining issues.[568] Steel Producers argue that the filing is deficient because it fails to identify the specific requirements that Filing Parties want the Commission to waive and, thus, fails to satisfy the Commission's tariff filing requirements in section 35.13 of the Commission's regulations.

487. ITC Companies-Wolverine and Michigan Commission support the requested July 16, 2010 effective date. Citing the Michigan Thumb Project, which was approved by the Midwest ISO Board on August 19, 2010,[569] ITC Companies-Wolverine assert that any delay in the proposed effective date would at the very least introduce uncertainty and at the worst call into question the cost allocation that will be available for projects included in the 2010 MTEP. Delaying the effective date could delay realization of the benefits of new MVP, according to ITC Companies-Wolverine.[570] Michigan Commission states that it strongly supports the requested effective date as consistent with stakeholder discussions and expectations to date by allowing MVP cost allocation treatment for projects that may be approved in Appendix A of the 2010 MTEP.[571] MidAmerican supports the proposed

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[568] IPL Comments at 41.

[569] ITC Companies-Wolverine explain that the Michigan Thumb Project is an approximately 140 mile, double circuit 345 kV transmission line and three new substations that will form a loop through the Thumb region of the Lower Peninsula of Michigan. They state that the project was designed to facilitate a State Renewable Portfolio Standard and other public policy objectives and will serve as the backbone of a transmission system designed to deliver wind power from the Thumb area. ITC Companies-Wolverine Comments at 18.

[570] *Id*.

[571] Michigan Commission Comments at 18.

requirement that projects must be approved after July 15, 2010, by the Midwest ISO Board to be eligible for consideration as an MVP.[572]

488. Illinois Commission does not oppose a July 16, 2010, effective date for the proposed SNUs proposal to address the "first mover/late comer" issue in the generator interconnection queue process.[573]

489. Several commenters expressed concern with the sufficiency of the stakeholder process.[574] For example, Designated PJM Parties argue that Filing Parties did not coordinate with other affected parties, including PJM and its load-serving entities. Thus, they claim that the MVP proposal is predicated on unsupported conjecture about circumstances external to Midwest ISO and ignores a host of relevant facts, such as the extent to which Renewable Portfolio Standards requirements in PJM states can be satisfied by local generation and transmission options, including wind generation. IPL argues that the proposal is not generally supported by participants across the region, stating that less than half of transmission owners signed on to the proposal.

490. Wisconsin Commission argues that while the stakeholders may, in the open light, craft a solution to a problem at hand, the RTO's ultimate decision may be made outside of the stakeholder process between the RTO and the large transmission owners threatening to leave. It urges the Commission to consider changing RTO rules to avoid undue influence from individual transmission owners and ensure that decisions are made with the public interest considered.

491. AWEA-WOW and Indiana OUCC express favorable views of the stakeholder process that led to the instant filings.[575] AWEA-WOW state that: 1) the MVP proposal was developed through a collaborative process with state authorities and participants across the Midwest ISO region; 2) the MVP proposal's broad regional support is reflected in the stakeholder process; and 3) many states support the final MVP proposal. Indiana OUCC states that there is significant value in the development of a proposal by

[572] MidAmerican Comments at 25-26.

[573] Illinois Commission Comments at 3, 54. Illinois Commission does oppose the requested July 16, 2010 effective date with respect to the MVP cost allocation proposal, as noted below.

[574] Designated PJM Parties Comments at 3-5; DP&L Comments at 3; IPL Comments at 11-13, Wisconsin Commission Comments at 5-6.

[575] AWEA-WOW Comments at 21-22; Indiana OUCC Comments at 3.

stakeholders in the region and that it was actively involved in the stakeholder process. Indiana OUCC believes that the proposal incorporates much of what stakeholders in the CARP and RECB meetings were able to agree with.

2. **<u>Answers</u>**

492. Filing Parties respond that: 1) there is no basis for rejection of the filing, because it is fully supported; 2) Filing Parties submitted all information required under section 35.13 for a filing that does not change rates, and they expressly noted that most requirements of section 35.13 are inapplicable to cost allocation filings; and 3) a trial-type hearing is unnecessary because no issues have been raised with the filing that cannot be resolved on the written record. Regarding the request for settlement procedures, Filing Parties argue that the Commission typically does not set a matter for settlement judge procedures that it has not also set for evidentiary hearing, and no such hearing is required. Further, since the July 15 Filing already reflects nearly a year of extensive stakeholder negotiations, it is not clear that further negotiations through settlement judge procedures would warrant delaying implementation of the proposal.[576]

493. Filing Parties also reiterate their support for a July 16, 2010, effective date, arguing that the July 9 filing, the October 23, 2009 Order and the extensive and open stakeholder process were sufficient to provide the parties with notice that changes to the Midwest ISO cost allocation methodology were coming, and provide good cause for granting the requested effective date. Regarding concerns that the requested effective date will not afford stakeholders sufficient time to review proposed transmission projects, Filing Parties state that all transmission projects will follow the same transmission planning processes in accordance with Order No. 890 independent of the approved effective date. They further state that granting the requested effective date would allow for prompt implementation of the MVP and SNU mechanisms and avoid uncertainty and additional costs for interconnection customers.[577] They also argue that a five months suspension is not justified, because no rate increase has been filed and no further procedures are needed to decide this filing.

494. Further, Filing Parties argue that there is no need to delay action on the proposal until the Commission issues a final rule on the Transmission NOPR. They argue that the proposal is designed to conform to the guidance contained in the Transmission NOPR and that it is uncertain when the Commission will issue a final rule or what the

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[576] Filing Parties October 18, 2010 Answer at 91-95.

[577] *Id.* at 95-97.

requirements of that rule will be. Further, the Commission has not established any moratorium on cost allocation changes while the Transmission NOPR is pending.[578]

495. MidAmerican argues that AMP's suggestion to time the upgrades that are eligible for MVP cost allocation with the Commission's order on the MVP cost allocation methodology would chill the construction of major new transmission in the Midwest ISO footprint. According to MidAmerican, many transmission facility concepts that would be logical candidates for an MVP designation could be considered to be projects already submitted for review by Midwest ISO, which would prevent the implementation of the MVP cost allocation in a timely manner and substantially delay the construction of needed new transmission facilities.[579]

496. Further, while MidAmerican recognizes the need of stakeholders to have the opportunity to review and comment on the planning of new transmission facilities prior to sharing in the costs of such facilities, it contends that a December 2011 effective date as proposed by OCC would unnecessarily delay the approval of projects as qualifying for MVP cost allocations. Therefore, MidAmerican supports consideration of delaying the effective date to July 1, 2011, provided that already-proposed (but not in-service, not under construction, or not already approved) projects prior to July 1, 2011, are eligible for consideration as MVPs. MidAmerican states that if such a change is adopted, this will increase the time stakeholders are allowed to review and comment on projects that become eligible for MVP cost allocation without unnecessarily delaying the approval of projects qualifying for MVP cost allocation.[580] MISO Northeast Transmission Customers state that, if the Commission provides for a later effective date, they argue that it should, at a minimum, require that projects that are included in Appendix A of the 2010 MTEP be eligible for MVP cost allocation.[581]

497. MidAmerican opposes altering the effective date to allow specific projects – such as the CapX2020 projects – to be eligible for MVP designation because that would provide preference to those projects over other projects that are potentially just as or more deserving of designation as MVPs.[582]

[578] *Id*. at 98-99.

[579] MidAmerican September 27, 2010 Answer at 7.

[580] *Id*. at 8.

[581] MISO Northeast Transmission Customers September 27, 2010 Answer at 5-6.

[582] MidAmerican September 27, 2010 Answer at 8-9.

498. ITC Companies note that the Commission granted waiver of notice to New York ISO to allow a tariff revision to take effect one day after filing, where it found that New York ISO's stakeholder process had provided six months actual notice of the filing in that case.[583] ITC Companies also note the October 23, 2009 Order's grant of a waiver of notice to allow the interim cost allocation proposal to become effective one day after filing, and that the Commission cited the ample notice of that filing through the stakeholder process that preceded the filing.

499. AMP contends that Filing Parties' reliance on the October 23, 2009 Order is misplaced, because there is no indication in that order that the Commission intended for the long-term cost allocation methodology to be made effective on any specified date. AMP states that it is more reasonable to presume that the Commission intended that its regulations, including the 60-day notice requirement, would be followed. Further, while stakeholders were on notice that a replacement methodology for the interim methodology was forthcoming, AMP disputes that stakeholders should be considered on notice that the effective date would be anything other than one established in full compliance with the Commission's regulations, including the 60-day notice requirement. In addition, Midwest ISO's Transmission Planning Business Practice Manual does not mention MVPs in its listing of project categories for cost allocation purposes.[584]

500. Regarding Filing Parties' arguments concerning delay and uncertainty, AMP responds that such arguments are based on the threat that, unless their request is granted, some set of wind-related upgrades the Commission might favor will not get built. AMP argues that the Commission should recognize that there are limits on the extent to which procedural regularity may be bent in the interest of serving any particular set of public policy goals and that the waiver request would take the Commission beyond those limits.[585]

501. AMP suggests that the only plausible rationale for Filing Parties' waiver request is that they deem it important, in order to assign a share of the Michigan Thumb Project's costs to ATSI, to have the MVP provisions made effective before the date on which the Midwest ISO Board approved the Michigan Thumb Project for inclusion in Appendix A of the MTEP. Yet, argues AMP, Filing Parties have argued that a departing Transmission Owner is responsible for the costs of projects planned and approved before

[583] ITC Companies September 27, 2010 Answer at 7-10 (citing *New York Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,238, at P 36 (2008) (September 12, 2008 Order)).

[584] AMP November 2, 2010 Answer at 7-9.

[585] *Id*. at 9-10.

the date of the Transmission Owner's actual withdrawal. If that were so, the waiver request would be unnecessary because Midwest ISO and the Midwest ISO Board would have until June of next year, when ATSI's withdrawal is complete, to get the MVP provisions into effect and have the Midwest ISO Board act. Thus, AMP asserts, Filing Parties' waiver request is simply an effort to hedge their bets on the assignment of Michigan Thumb Project costs to ATSI. AMP argues that this does not rise to the level of good cause for waiver.[586]

502. Regarding the stakeholder process, Filing Parties state that, prior to July 15, 2010, Midwest ISO engaged in over 30 meetings with state regulators and stakeholders since the July 9, 2009, interim cost allocation filing. The filed MVP proposal involves "minor tweaks" of the supporting Transmission Owner proposal and the OMS CARP proposal, and the common theme among these proposals is the provision for broad regional sharing to load of projects intended to integrate renewable energy projects. Thus, Filing Parties disagree that the MVP proposal represents a fundamental shift in the types of cost allocation methodologies that had been reviewed and supported through the stakeholder process.[587]

3. Commission Determination

503. We grant waiver of the 60-day prior notice requirement to permit an effective date of July 16, 2010, for good cause shown.[588] Where the Commission has directed an applicant to conduct a stakeholder process that would result in the applicant making a new filing, as the Commission did in the October 23, 2009 Order where it stated that Midwest ISO was expected to file a long-term cost allocation proposal on or before July 15, 2010, the Commission has found that stakeholders were put on notice of such filing.[589] In this instance, stakeholders had approximately nine months prior notice of the instant filing.

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[586] *Id*. at 10-11.

[587] Filing Parties October 18, 2010 Answer at 90.

[588] 16 U.S.C. § 824d (2006); 18 C.F.R. § 35.11 (2010); *Central Hudson Gas & Electric Corp*., 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 (1992).

[589] *See, e.g*., September 12, 2008 Order, 124 FERC ¶ 61,238 at P 36 (finding good cause for waiver, noting that the stakeholder process provided actual notice of the filing); *Midwest Indep. Transmission Sys. Operator, Inc*., 114 FERC ¶ 61,169, at P 26, *order on reh'g*, 115 FERC ¶ 61,293 (2006) (same); *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,245, at P 6 (2006) (finding good cause for waiver based, in part, on the stakeholder

(continued…)

504. We thus disagree with arguments that stakeholders were not afforded sufficient opportunity to review the instant proposal or that the perceived inadequacy of that process should provide a basis for delaying the effective date. As directed by the October 23, 2009 Order, Filing Parties submitted quarterly informational status reports on the stakeholder process leading up to the July 15 Filing. These quarterly reports described the proposals that were under consideration by the stakeholders and the actions taken on such proposals.[590] In addition, the quarterly reports indicate that stakeholder participation in the development of the instant proposal was generally open, transparent and collaborative.

505. In addition, stakeholders have been afforded an opportunity to challenge the instant proposal through the notice and comment procedures in this proceeding, including an extended time for comments. Further, as Filing Parties note, all transmission projects including the MVPs will follow the transmission planning processes required by Order No. 890 independent of the effective date adopted here.

The Commission orders:

(A) Filing Parties' request for waiver of the prior notice requirement is hereby granted, as discussed in the body of the order.

(B) Filing Parties' proposed Tariff revisions are hereby conditionally accepted for filing, to become effective on July 16, 2010, as discussed in the body of this order.

(C) Filing Parties are hereby directed to submit a compliance filing within 60 days of the date of this order, as discussed in the body of this order.

(D) Filing Parties are hereby directed to submit a further compliance filing on

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process that preceded the filing).

[590] With respect to arguments that Filing Parties have not satisfied the requirements of section 35.11, we disagree. We disagree that the potential consequences of not obtaining a waiver of notice are merely speculative, for the reasons cited by Filing Parties and their witness Moeller, cited above. In addition, the application indicates how costs will be allocated under its proposal, and the effective date has a bearing on which projects will be eligible for regional cost sharing; thus, it does address the effects of the July 16, 2010 effective date on customers. Further, the instant application concerns cost allocation, not a revenue requirement increase; thus, it is not dispositive that the proposed effective date is not prescribed by a contract. Finally, the Commission's regulations and precedent do not require that there be an "emergency" to find good cause for waiver.

or before June 1, 2011, as discussed in the body of this order.

(E) Filing Parties are hereby directed to submit ongoing annual information reports, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

APPENDIX

INTERVENTIONS WITH SUBSTANTIVE COMMENTS

Acciona Wind Energy USA LLC (Acciona)
American Electric Power Service Corporation (AEP)[591]
Alliant Energy Corporate Services, Inc. (Alliant)
American Forest & Paper Association (AF&PA)
American Municipal Power, Inc. (AMP)
American Transmission Company LLC (ATC)[592]
American Wind Energy Association and Wind on the Wires (jointly, AWEA-WOW)
Association of Businesses Advocating Tariff Equity (ABATE)
Basin Electric Power Cooperative (Basin)
CPV Renewable Energy Company, LLC (CPV)
Designated PJM Parties[593]

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[591] AEP submitted the filing on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Southwest Electric Power Company, Public Service Company of Oklahoma, AEP Southwestern Transmission Company, Inc., and AEP Oklahoma Transmission Co., Inc.

[592] ATC submitted the filing with ATC Management, Inc.

[593] Designated PJM Parties include: Baltimore Gas and Electric Company (BG&E); Duquesne Light Company (Duquesne); Exelon Corporation (Exelon); Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (Penelec) and Jersey Central Power & Light Company (JCPL); "collectively doing business as FirstEnergy"; PHI Companies (Pepco Holdings, Inc. and its affiliates Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company); Monongahela Power Company, The Potomac Edison Company and West Penn Power Company (collectively, Allegheny Power); Old Dominion Electric Cooperative (Old Dominion); PPL PJM Companies (PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; and Lower Mount Bethel Energy, LLC); Public Service Electric and Gas Company (PSEG); and UGI Utilities, Inc. (UGI).

The Dayton Power and Light Company (DP&L)
Dominion[594]
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (Duke)
Edison Mission Energy (Edison Mission)
Electric Power Supply Association (EPSA)
E.ON Climate & Renewables North America LLC (E.ON)
Exelon
FirstEnergy Service Company (FirstEnergy)[595]
Fresh Energy[596] (filed comments only)
Gamesa Energy USA, LLC (Gamesa)
Hoosier Energy Rural Electric Cooperative, Inc. and Southern Illinois Power Cooperative (jointly, Hoosier-SIPC)
Iberdola Renewables, Inc. (Iberdola)
Illinois Commerce Commission (Illinois Commission)
Illinois Municipal Electric Agency (IMEA)
Indiana Office of Utility Consumer Counselor (Indiana OUCC)
Indianapolis Power & Light Company (IPL)
Indiana Utility Regulatory Commission (Indiana Commission)
Industrial Customers[597]
Integrys[598]

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[594] Dominion Resources Services, Inc. (DRSI) submitted the filing on behalf of Virginia Electric and Power Company (jointly, Dominion).

[595] FirstEnergy submitted the filing on behalf of The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and The Toledo Edison Company, FirstEnergy Solutions Corporation, and American Transmission Systems, Inc. (ATSI).

[596] Fresh Energy includes: Center for Rural Affairs, Clean Wisconsin, Fresh Energy, Great Plains Institute, Iowa Environmental Council, Iowa Policy Project, Iowa Renewable Energy Association, Izaak Walton League of America, National Wildlife Federation, Natural Resources Defense Council, Ohio Environmental Council, Renew Wisconsin, Renew Missouri, and Union of Concerned Scientists.

[597] Industrial Customers include: Coalition of Midwest Transmission Customers (CMTC), Minnesota Large Industrial Group (Minnesota Industrials), Electricity Consumers Resource Council, Illinois Industrial Energy Consumers (Illinois Industrials), and Wisconsin Industrial Energy Group.

[598] Integrys includes: Wisconsin Public Service Corporation, Upper Peninsula Power Company, and Integrys Energy Services, Inc.

International Transmission Company (ITC), Michigan Electric Transmission Company, LLC (METC), ITC Midwest LLC (ITC Midwest), and Green Power Express (collectively, ITC Companies) and Wolverine Power Supply Cooperative, Inc. (Wolverine) (jointly, ITC Companies-Wolverine)
Iowa Utilities Board (Iowa Board)
Iowa Office of Consumer Advocate (Iowa Advocate)
Joint Protestors[599]
MISO Northeast Transmission Customers[600]
Michigan Citizens Against Rate Excess (MICH-CARE)
MPPA
Michigan Public Service Commission (Michigan Commission)
MidAmerican Energy Company (MidAmerican)
Midwest Generators[601]
Midwest TDUs[602]
Minnesota Public Utilities Commission (Minnesota Commission) and Minnesota Office of Energy Security (jointly, Minnesota Commission-Minnesota Security)
NextEra Energy Resources, LLC (NextEra)
Northern Indiana Public Service Company (NIPSCO)
Oak Creek Energy Systems, Inc. (Oak Creek)
Office of the Ohio Consumers' Counsel (OCC)
Organization of MISO States (OMS)[603]

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[599] Joint Protestors include: Dynegy Power Marketing, Inc., Dynegy Midwest Generation, Inc., DC Energy Midwest, LLC, Cargill Power Markets, LLC, and Westar Energy, Inc.

[600] MISO Northeast Transmission Customers include: Michigan Department of Attorney General (Michigan Attorney General), ABATE, Consumers Energy Company (Consumers Energy), The Detroit Edison Company, Michigan Municipal Electric Association (Michigan Municipals), and Michigan Public Power Agency (MPPA).

[601] Midwest Generators include: Invenergy Wind Development LLC, and Invenergy Thermal Development LLC (jointly, Invenergy), and Renewable Energy Systems Americas, Inc. (RES Americas).

[602] Midwest TDUs include: Madison Gas & Electric Company, Missouri Joint Municipal Electric Utility Commission, Midwest Municipal Transmission Group, Missouri River Energy Services (MRES), Prairie Power, Inc., and WPPI Energy (WPPI).

[603] OMS states that its comments are supported by the following OMS members: Indiana Commission, Iowa Board, Michigan Commission, Minnesota Commission, Missouri Public Service Commission (Missouri Commission), Montana Public Service

(continued…)

PSEG Companies[604]
PJM Interconnection, LLC (PJM)
Southern Indiana Gas and Electric Company (Vectren South)
Southwestern Electric Cooperative, Inc. (Southwestern)
Senator Debbie Stabenow (Michigan Letter) (letter forwarding a constituent's comments)
Steel Producers[605]
SummitWind, LLC (SummitWind) (filed comments only)
Tenaska Power Services Co. (Tenaska)
Wisconsin Electric Power Company (Wisconsin Electric)
Public Service Commission of Wisconsin (Wisconsin Commission)
Wisconsin Industrials[606]
Xcel Energy Services, Inc. (Xcel)[607]

OTHER INTERVENTIONS

Allegheny Electric Cooperative, Inc.
Allegheny Power
ArcelorMittal USA Inc.
Baltimore Gas and Electric Company
Buckeye Power, Inc.
Calpine Corporation
CMTC
Consumers Energy
Dairyland Power Cooperative (Dairyland)
The Detroit Edison Company (Detroit Edison)

Commission (Montana Commission), North Dakota Public Service Commission (North Dakota Commission), South Dakota Public Utilities Commission (South Dakota Commission), and Wisconsin Public Service Commission (Wisconsin Commission).

[604] PSEG Companies include: PSEG, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[605] Steel Producers include: Nucor Steel-Indiana, Inc. and Steel Dynamics, Inc.

[606] Wisconsin Industrials include: Wisconsin Industrial Energy Group, Wisconsin Cast Metals Association, Midwest Food Processors Association and Wisconsin Paper Council.

[607] Xcel submitted the filing on behalf of Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (jointly, Northern States).

DRSI[608]
Duquesne Light Company
enXco Development Corporation (enXco)
FC Energy Finance I, Inc. and JPM Capital Corporation
Illinois Industrials
JPMorgan Ventures Energy Corporation and BE KJ LLC
LS Power Associates, LP
Maryland Public Service Commission
Michigan Attorney General
Michigan Municipals
Michigan South Central Power Agency (MSCPA)
Midland Cogeneration Venture Limited Partnership
Minnesota Industrials
Minnesota Municipal Power Agency
Minnkota Power Cooperative, Inc.
Missouri Commission
NRG Power Marketing, LLC
Old Dominion
Pennsylvania Public Utility Commission
PHI Companies
PPL PJM Companies
RRI Energy, Inc.

ANSWERS

EPSA (September 27, 2010)
ITC Companies (September 27, 2010)
MidAmerican (September 27, 2010)
MISO Northeast Transmission Customers (September 27, 2010)[609]
Hoosier-SIPC (September 27, 2010)
MidAmerican (October 8, 2010)
MISO Northeast Transmission Customers (October 12, 2010)
Midwest Independent Transmission System Operator, Inc. and Midwest ISO

[608] DRSI filed a motion to intervene on behalf of Dominion Energy Kewaunee, Inc. and Dominion Energy Marketing, Inc.

[609] For the purposes of this filing, MISO Northeast Transmission Customers include Consumers Energy, Detroit Edison, Michigan Municipals and MMPA.

Transmission Owners[610] (Filing Parties) (October 18, 2010)
MISO Northeast Transmission Customers (November 1, 2010)
MPPA and MSCPA (jointly, Michigan Agencies) (November 1, 2010)
AMP (November 2, 2010)
Designated PJM Parties (November 2, 2010)[611]
Duke (November 2, 2010)
E.ON (November 2, 2010)
Exelon (November 2, 2010)
FirstEnergy (November 2, 2010)
Iberdrola and Invenergy (jointly, Iberdrola-Invenergy) (November 2, 2010)
Integrys (November 2, 2010)
Midwest TDUs (November 2, 2010)
PSEG Companies (November 2, 2010)
RES Americas, Inc. (November 2, 2010)
AWEA-WOW (November 4, 2010 Answer)
AWEA-WOW (November 4, 2010 Attachments to Answer)
Dominion (November 5, 2010)[612]
enXco (November 8, 2010)
CMTC (November 8, 2010)
AMP (November 17, 2010)
MISO Northeast Transmission Customers (November 19, 2010)
AWEA-WOW (November 23, 2010 Amended Answer)
Illinois Commission (November 23, 2010 Answer)

[610] For the purposes of this filing, Midwest Transmission Owners include: Ameren Services Co., as agent for Union Electric Co., Central Illinois Public Service Co., Central Illinois Light Co., and Illinois Power Co.; ATC; Dairyland; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; NIPSCO; Northern States; Northwestern Wisconsin Electric Co.; Otter Tail Power Co.; and Southern Minnesota Municipal Power Agency.

[611] For the purposes of this filing, Designated PJM Parties include: BG&E; Duquesne; Exelon; MetEd, Penelec, and JCPL; "collectively doing business as FirstEnergy"; PHI Companies; Allegheny Power; Old Dominion; PSEG; and UGI.

[612] Dominion submitted the filing on behalf of Dominion Virginia Power.