Generator Interconnection Driven Network Upgrade Cost Recovery

Revised Straw Proposal

September 6, 2016

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1 Introduction and Background

The ISO tariff requires Participating Transmission Owners (PTOs) to reimburse interconnection customers (ICs) whose generators are interconnecting to their systems for the costs of reliability[1] and local deliverability network upgrades necessary for the interconnection. The PTOs then include those network upgrade reimbursement costs in their FERC-approved rate bases, requiring ratepayers to pay those costs through either low- or high-voltage transmission access charges (TAC). Network upgrades 200 kV and above are considered high-voltage, and upgrades below 200 kV are considered low-voltage. The high-voltage TAC is a "postage stamp rate" based on the aggregated transmission revenue requirements ("TRR") of all PTOs for all high-voltage facilities on the ISO system. In contrast, the low-voltage TAC is PTO-specific, charged only to customers within the service area of the PTO who owns the facilities.

The current practice could soon negatively impact ratepayers who are not the sole beneficiaries of the upgrades, but who solely bear their costs. For example, if a large generator or a large number of generators with significant low-voltage network upgrade costs interconnect to a PTO with a relatively small rate base, that PTO's rate base may increase significantly simply as a result of the current cost allocation framework. This issue first presented itself recently in the Valley Electric Association (VEA) area, but the issue itself is neither based on the size of a utility nor its rate base, but is based on principles of just and reasonable cost allocation. These low-voltage VEA interconnections are an example of the issue.

Interconnection-driven network upgrades increase the pool of generation connected to the ISO Controlled Grid, thus providing benefits to the entire ISO regardless of the voltage level at which they happen to interconnect. The costs of such upgrades should therefore be recovered in the same manner as high-voltage network upgrades, *i.e.*, from the ISO ratepayers as a whole rather than only from the ratepayers of the interconnecting PTO.

In responding to the August 1, 2016 Issue Paper and Straw Proposal, stakeholders such as SDG&E, PG&E, and NRG agreed that in light of current circumstances FERC could find that it is inappropriate for low voltage customers to solely bear the costs of low voltage network upgrades required to interconnect generators. Other stakeholders ignored or demurred on this issue. As such, this paper will outline the stakeholder process, discuss FERC cost allocation principles and why generation driven network upgrades benefit the

[1] Reimbursement for reliability network upgrades (RNU) is limited to $60,000 per installed MW of capacity; there is no limit on reimbursement for costs of other qualifying network upgrades.

grid as a whole, respond to stakeholder suggestions that this should be part of the larger effort to develop a regional transmission access charge, respond to other stakeholder comments and suggestions, and present the ISO's revised straw proposal.

2 Stakeholder process

The California Department of Water Resources (CDWR), Northern California Power Agency (NCPA), and Silicon Valley Power on behalf of the Bay Area Municipal Transmission group (BAMx) expressed concern that this process may be moving forward too rapidly; whereas, the Large Scale Solar Association, California Wind Energy Association, Independent Energy Producers Association, and SPower (collectively, the Generators) and VEA reinforced the need to move forward expeditiously. As discussed in Section 5, below, the ISO believes this issue is narrowly focused and should move forward on an expedited basis. Timely resolution of this issue remains critical because there are many interconnection customers currently in the study process or generation interconnection agreement (GIA) negotiation phase that are dependent on the outcome of this stakeholder process. Therefore, the ISO has set out an accelerated stakeholder process schedule and appreciates stakeholder understanding and participation in this effort.

Stakeholder process schedule		
Step	Date	Activity
Draft Issue Paper/Straw Proposal	August 1, 2016	Post Issue Paper/Straw Proposal
	August 8, 2016	Stakeholder web conference
	August 19, 2016	Stakeholder comments due
Revised Straw Proposal	September 6, 2016	Post Revised Straw Proposal
	September 13, 2016	Stakeholder web conference
	September 20, 2016	Stakeholder comments due
Draft Final Proposal	TBD	Post Draft Final Proposal
	TBD	Stakeholder web conference
	TBD	Stakeholder comments due
Board approval	December 14/15, 2016	ISO Board of Governors meeting

3 FERC Cost Allocation Principles

Order Nos. 890 and 1000 set forth FERC's cost allocation principles. They are based on two significant principles for FERC: (1) rates should reasonably align cost allocation for any given transmission facility or group of facilities with the distribution of benefits from the facilities; and (2) cost allocation is not an exact science. FERC recognizes the need for allows ISOs/RTOs flexibility in allocating costs for transmission facilities as long as there is reasonable cost-benefit alignment, adequate incentives to construct new transmission, and general support among the participants across the ISO territory.[2] In Order No. 1000, FERC specified six cost allocation principles for new transmission projects:

1. Costs must be allocated in a way that is roughly commensurate with benefits.
2. Costs may not be allocated involuntarily to those who do not benefit.
3. A benefit to cost threshold may not exceed 1.25.[3]
4. Costs may not be allocated involuntarily to a region outside of the facility's location.
5. The process for determining benefits and beneficiaries must be transparent.
6. A planning region may choose to use different allocation methods for different types of projects.[4]

Although FERC generally was addressing transmission-planning-process driven projects in these orders, these cost allocation principles still can inform this initiative. The ISO's current cost allocation scheme for generator-interconnection-driven upgrades may not satisfy the first two principles, which effectively are two sides of the same coin, because ratepayers who benefit from the upgrades may escape their costs entirely, while ratepayers who may only slightly benefit from the upgrades bear all the costs, as exemplified by the current VEA situation.

4 Generators provide benefits to the ISO markets for the entire region

NRG, CDWR, NCPA, SIX Cities, and BAMx state that the ISO needs to show particular network upgrades in question benefit the entire ISO Grid. This claim raises two separate issues - does the generation enabled by the network upgrades benefit the entire ISO grid, and in contrast, do the network upgrades benefit the local utility?

New generation development supports the entire grid in a number of ways. The ISO's market produces the efficient, least-cost market operation cost-optimizing between the

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[2] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559; *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).

[3] This principle refers to the threshold criterion a transmission planning entity applies to approve an economic transmission project; in effect, it says that the threshold cannot be so high as to prevent approval of projects whose benefits are shown to exceed their costs.

[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 612 et seq. (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012*), aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

production of energy and ancillary services, and the new entry of additional resources puts downward pressure on the overall cost of energy and other services. New generation can provide lower cost and more efficient opportunities for accessing resource adequacy capacity as well.

Further, LSEs that need additional renewable generation to meet state renewables portfolio standards are incentivized to procure renewable generation from the lowest cost resource, regardless of whether that resource is within their own service territories. Past contracting practices have indicated that LSEs contract for significant resources outside of their own service territories, and developers are aware of this as they develop generation projects for the broader market and not just the local LSE. This is supported by the ISO's "one system" transmission planning process that looks holistically at needs within the entire footprint. It is further reinforced by the renewable generation portfolios developed by the CPUC for purposes of policy-driven transmission planning, which focus on the optimal resources for overall need regardless of service territory, and do not allocate renewable generation target areas among LSE service territories. This point is demonstrated clearly by the fact that the significant amount of proposed renewable generation in the VEA service territory that is reflected in the ISO queue constitutes multiples of the entire VEA load. Not only have LSEs contracted for resources within other ISO LSE service territories, but they have contracted with resources outside of the ISO balancing authority area altogether.

Some stakeholders have speculated that the local network upgrades associated with the generator interconnections could provide some benefits to the local utilities, and that these benefits must be considered. Considering this speculation in the near-term, the ISO notes that the ISO's comprehensive transmission planning process considers reliability needs at the earliest stage. If the ISO identifies a reliability need that may be addressed through a generator interconnection driven network upgrade, the project proceeds as a reliability driven upgrade. However, where the ISO's transmission planning process determines that a generator interconnection driven upgrade may provide transmission benefits independent of the interconnection (most likely an independent reliability need), the ISO removes them from interconnecting generators' cost responsibility. Further, in considering a longer-term view, the ISO's experience shows that few, if any, generation interconnection driven network upgrades provide material benefits to the local utility because they have been predominantly local substation additions that are needed solely to facilitate an interconnecting generator. The ISO also notes that its proposal does not entail the local utility avoiding all cost responsibility - it would remain responsible for its share of the HV TAC and the costs recovered through that rate.

In its comments, the Office of Rate Payer Advocates (ORA) argues that allocating generator-interconnection-driven costs regionally may jeopardize the CPUC's ability to "protect California ratepayers from the costs of VEA's potentially unreasonable transmission projects."[5] This argument overlooks several key facts. The ISO's current generator-interconnection-driven cost allocation principles may result in improper incentives. Under the current rules, generators may seek to interconnect to high-voltage transmission facilities, even where interconnecting to low-voltage transmission facilities would be more cost-efficient (such as VEA's) so as to avoid saddling only local ratepayers with all of the costs (thereby potentially facing local ratepayer backlash, reluctance from permitting authorities, or litigation). Further, transmission owners similarly would be incentivized to promote only interconnections whose costs can be allocated regionally - so their ratepayers would not bear all of the costs of interconnecting - even if an interconnection to low-voltage facilities would be more cost-efficient. This would increase the overall costs for ratepayers.

Changes resulting from this initiative will help, not hinder, the CPUC's ability to protect California ratepayers from unnecessary cost increases. As described above, failing to fix this problem could result in more costly interconnections to high-voltage transmission facilities just to avoid this issue. Moreover, California ratepayers benefit when generators can find the most cost-effective points of interconnection to provide power to California Load Serving Entities (LSEs). ORA would sacrifice the pursuit of lower-cost interconnections even though this initiative will in no way affect the CPUC's ability to review the costs of Power Purchase Agreements (PPAs) for California LSEs, which ultimately determines which resources move forward.

The CAISO notes that under the CAISO's existing cost allocation methodology high-voltage transmission facilities built only in Nevada are partially allocated to California ratepayers where a Nevada LSE is a member of the CAISO. This initiative does not change that allocation methodology, and it could slightly increase the total costs in the high voltage TAC as slightly more "low-voltage" costs are allocated regionally. But these cost increases potentially would be mitigated by the wider-market and efficient interconnection benefits described above.

CDWR, Generators, NCPA, and Six Cities, similarly urge the ISO (or VEA) to evaluate VEA's total benefits against its total costs in being a member of the CAISO. CDWR, for example, states that the ISO fails to demonstrate "that the [cost] increase outweighs the savings VEA ratepayers have realized by being within the ISO footprint or, in fact, the benefits they will realize from the generator interconnections in question."[6] Regarding, the latter, under the current methodology for allocating the costs of generator interconnection network upgrades, VEA would assume all of the costs for generator interconnections that overwhelmingly benefit ratepayers outside of VEA. VEA does not have a compelling need to procure additional capacity from these generators. Even if it did, it would not need more capacity than its entire load (which these generators represent).

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5 ORA Comments at 2.
6 CDWR Comments at 2.

The former argument - that the ISO and VEA should consider these facilities' costs against VEA's overall benefits from being a member of the ISO - is not aligned with FERC's cost causation principles, which take a facility-by-facility approach to cost allocation. FERC and the U.S. courts have been clear that the costs of facilities must be allocated commensurate with their benefits. Neither would allow the ISO to allocate costs to a transmission owner that are not commensurate to its benefits just because it is more cost-effective for the transmission owner to be in an ISO/RTO than out.

BAMx questioned why the proposal should not apply more widely, such as low voltage network paths that parallel high voltage paths and could be argued to support and provide benefits to the high voltage grid, especially given the commenter's view that the ISO had only made general reference to system benefits as the basis for the proposed cost recovery change. There are a number of issues to respond to here. First, in this revised straw proposal, the ISO has provided more discussion of the reasons for the proposal, including discussion of the benefits network upgrades provide to the system as a whole. The network upgrades under discussion are being developed primarily for accessing generation, whereas parallel low-voltage systems are developed primarily for the purposes of serving local area load. Second, the unscheduled flows on low voltage parallel paths tends to be more of a detriment than an advantage because those flows can cause thermal limitations to be reached on the low-voltage system that limit the use of the high-voltage system. Although many of these parallel paths were created as higher voltage transmission was developed as an overlay on the existing grid, it is not uncommon to open the low-voltage parallel paths to alleviate problems caused by the unscheduled parallel flows. Third, FERC historically has not considered reciprocal loop flows on parallel paths to be a valid reason to allocate costs between parties.

5 Relationship to the regional TAC Options initiative

Several parties commented that the present issue should be included in the ISO's regional TAC Options initiative, which is addressing transmission cost allocation for a future expanded balancing authority area formed by the integration of a large new PTO with a load service territory. The ISO does not think this would be appropriate or necessary. First, as noted earlier, there is some urgency to the present matter, and incorporating it into the larger TAC Options initiative would delay its resolution. Interconnection customers currently in the queue stand to be affected by the outcome of this initiative, and continued uncertainty adversely affects their projects.

Second, the cost allocation provisions adopted under the TAC Options initiative are explicitly focused on how to allocate costs across a larger BAA formed by the integration of at least one large new PTO with a load service territory. The present matter needs to be resolved for the current ISO footprint even if an expanded ISO BAA never comes to pass. Thus, it is not practical to combine the present initiative, which pertains immediately to the current ISO area, with a larger initiative whose results are intended for a possible, future implementation date that is uncertain, but is at least several years in the future.

Third, considering this matter outside of the larger TAC Options initiative should not adverse impact either initiative. Both initiatives are explicitly attending to FERC principles regarding transmission cost allocation. That said, the ISO recognizes that the results from this initiative may need to be incorporated into the TAC Options initiative after this initiative is complete.

6 Straw Proposal

The ISO has reviewed the stakeholder comments received on the draft straw proposal. After careful consideration the ISO proposes to move forward with Option 1 from the draft straw proposal, but not Option 2. The ISO continues to believe that it is essential that any solution to this issue be compatible with, and retain the fundamental design and features of, the Generation Interconnection and Deliverability Allocation Procedures (GIDAP), Appendix DD of the ISO Tariff, specifically:

- Two-phase cluster-study approach with annual reassessments;
- Cost certainty to interconnection customers early in the study process through cost caps; and
- Reliability and local deliverability network upgrades would continue to be reimbursed to interconnection customers upon commercial operation in accordance with the GIDAP.

Six Cities and BAMx suggest that the ISO should revisit the policy of ratepayer reimbursement of network upgrade costs and consider having the interconnection customers bear these costs. The Generators, on the other hand, state that “this potential problem would not justify significant changes in the current long-standing and much-negotiated transmission-cost structure that would impose additional costs on interconnecting generators.” As explained in the draft straw proposal, the ISO does not support options that would shift all network upgrade costs to the interconnection customers who trigger them. Doing so would represent a fundamental paradigm shift for generation development and capacity procurement in the ISO region, and likely would raise the myriad issues with which other regions struggle even without California’s nation-leading renewable portfolio and storage targets.[7]

[7] *See* American Wind Energy Association, Petition for Rulemaking, FERC Docket No. RM15-21-000 (July 7, 2015).

Option 1 (ISO Proposal)

Include the cost of generator-triggered low-voltage facilities in the PTO's high-voltage TRR for recovery through the high-voltage TAC. This option recognizes that generators provide energy and ancillary services to the ISO markets for the entire region, and generally support public policy goals including resource adequacy, reliability, and renewable generation. The conceptual approach here is that once interconnected to the ISO controlled grid (whether above or below 200 kV), a resource is connected to the ISO market and benefits all ISO ratepayers, not just those in the local area. This option would apply to all PTOs, is straightforward, and would be fairly simple to implement.

The draft straw proposal proposed that the PTOs would maintain their cost allocations for generator-triggered network upgrades already in service, and this revised allocation would only apply going forward. However, PG&E and SDGE both proposed that the logic applies equally to RNUs and LDNUs that have already been built and whose costs have yet to be recovered from loads (*e.g.*, undepreciated rate base for in-service RNU and LDNU costs that were reimbursed to an IC). BAMx also questioned "Why is it reasonable to assume that only new installations of such facilities provide such benefits? If such benefits are shown to exist, all similar facilities, both old and new, should be treated in the same fashion." The ISO agrees that this could be the case and seeks additional stakeholder input on this question.

PG&E, SDGE, and VEA supported Option 1. CDWR, ORA, NCPA, BAMx, Six Cities, and SCE opposed Option 1. Sections 3, 4, and 5 above provide responses to a majority of stakeholder objections to Option 1. The ISO respectfully request stakeholders who objected to the draft straw proposal to reconsider their position on Option 1 in light of these responses and the ISO's view that the current cost allocation methodology can yield problematic results that are not aligned with FERC's cost allocation principles.

Option 2

Stakeholders did not support Option 2 from the draft issue paper and straw proposal. Stakeholders felt that any split of cost recovery for generation driven low voltage network upgrades between the low-voltage and high-voltage TAC would be arbitrary. Even those stakeholders who entertained Option 2, *arguendo*, took opposite sides as to what the percentage split should be: some argued for a very high percentage and some for a very low percentage.

Alternate Stakeholder Proposed Options

Two stakeholders propose alternate options for consideration: First, "SCE proposes a new 'Option 3' to mitigate rate shock to VEA customers by extending the time period for which an interconnection customer receives repayment of network upgrades so that the levelized payments do not cause rate shock to VEA customers." SCE suggested that the CAISO seek a one-time waiver and focus on the narrow issue of rate shock. Although the draft straw proposal illustrated the current impacts to VEA and the possibility of rate shock to VEA ratepayers, this paper argues that the real issue is appropriate cost allocation for generation driven network upgrades. SCE's proposal does not remedy this fundamental problem, and therefore the ISO does not propose this as a viable option.

Second, NRG's proposed that, "[r]ather than spreading local costs system-wide, or leaving some or all the costs on the shoulders of load that is not benefitting from the generation within its service area, the CAISO should consider whether the generator-interconnection LV network upgrade costs in one PTO's service area should be allocated to the load within the service area of the PTO that is the intended recipient and beneficiary of the power supplied by that remotely-located generator." Sections 3 and 4 above address FERC cost allocation principles and indicate why the ISO believes that generation driven network upgrades benefits the ISO as a whole and not just the interconnecting PTO or the LSE that has a PPA. Moreover, allocating NU costs to an LSE that contracts with the interconnecting generator would amount to a major paradigm shift in cost allocation policy, comparable in the severity of the policy change to having the interconnection customer bear the NU costs. The proposal also would not address situations where the PPA counterparty is not jurisdictional to the ISO. For these reasons, the ISO does not believe this as a viable option.

Reference Information

The ISO included Tables 1 and 2 in the draft straw proposal to provide the reader with a perspective of the impact to the high voltage TAC if Option 1 is adopted and applied on a going forward basis. The ISO is not able to provide similar data if Option 1 is applied to network upgrades that are already in service and costs have yet to be recovered in time for this revised straw proposal. The ISO is working with the PTOs to see if this information can be available for discussion by the upcoming stakeholder call or future proposal papers.

For reference, there are currently 115 active generation interconnection projects in the CAISO queue that have received their Phase II Study Reports (active projects through cluster 7, Independent Study Process and Fast Track projects). Table 1 below shows the estimated dollar amount for low- and high-voltage reliability and local deliverability network upgrade costs for the 115 active projects. The 115 projects represent approximately 12,000 MW of additional renewable capacity, which is roughly equivalent to the estimated additional renewable capacity required for the ISO to reach the 50% RPS requirement in 2030. Accounting for the conventional and the renewable capacity, the 115 projects represent approximately 16,000 MW of additional generating capacity.

Table 1

Estimates of Low & High-Voltage RNU and LDNU Costs ($ millions)

PTO	Number of active projects with executed GIAs	Total estimated Low-voltage (<200kV) network upgrade costs	Total estimated high-voltage (≥200kV) network upgrade costs
PG&E	47	$90.46	$86.33
SCE	36	$1.85	$737.03
SDGE	28	$9.38	$43.91
VEA	4	$9.12	$12.82
TOTAL	115	$110.81	$880.09

Also for reference, Table 2 shows the current annual low and high-voltage TRRs as of 6/1/2016.

Table 2[8]

Current Annual Low & High-Voltage TRRs as of 6/1/2016

PTO	Filed Annual HV TRR ($)	Filed Annual Gross Load (MWh)	HV Utility Specific Rate ($/MWh)	TAC Rate	TAC Amount	Filed Annual LV TRR ($)	LV Utility Specific Rate ($/MWh)	Utility Specific Combined TAC
PG&E	$607,131,854	90,445,937	$6.7126	$11.1281	$1,006,488.545	$769,307,250	$8.5057	$15.2184
SCE	$1,004,417,227	90,511,765	$11.0971	$11.1281	$1,007,221,083	$40,241,005	$0.4446	$11.5417
SDGE	$469,609,354	20,824,991	$22.5503	$11.1281	$231,741,918	$298,854,329	$14.3508	$36.9010
Anaheim	$29,372,296	2,507,620	$11.7132	$11.1281	$27,904,966			$11.7132
Azusa	$3,163,102	257,416	$12.2879	$11.1281	$2,864,543			$12.2879
Banning	$1,274,841	144,652	$8.8132	$11.1281	$1,609,697			$8.8132
Pasadena	$14,679,975	1,231,980	$11.9158	$11.1281	$13,709,557			$11.9158
Riverside	$32,665,860	2,180,985	$14.9776	$11.1281	$24,270,150			$14.9776
Vernon	$2,973,458	1,181,728	$2.5162	$11.1281	$13,150,350			$2.5162
DATC Path 15	$25,407,824			$11.1281				
Startrans IO	$3,587,536			$11.1281				
TBC	$118,857,411			$11.1281		$9,117,184	$0.1008[9]	
Citizens Sunrise	$10,605,982			$11.1281				
Colton	$3,485,980	372,179	$9.3664	$11.1281	$4,141,633			
VEA	$11,934,201	544,970	$21.8988	$11.1281	$6,064,463	$3,413,410	$6.2635	$28.1623
Total	$2,339,166,904	210,204,223	$11.1281		$2,339,166,904	$1,120,933,178		

[8] This table can be found in the following document: http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJun1_2016.pdf

[9] The LV utility specific rate for TransBay Cable is derived by dividing the LV TRR by PG&E's gross load, as Trans Bay Cable does not have a load service area, and its low voltage costs are recovered from PG&E customers.

As discussed in the Issue and Straw Proposal, as an example of the impact of low voltage network upgrade costs on a relatively small PTO's rate base versus spreading those costs across the system, if VEA required $9.12 million in low voltage network upgrade costs, the approximate impact on VEA's low-voltage TAC would be an increase of about $2.15/MWh (from $6.26/MWh to $8.41/MWh), a 34% increase.[10] As mentioned above, this would be a significant impact on VEA ratepayers for facilities that do not provide VEA ratepayers with a commensurate benefit. However if this $9.12 million were shared across the system and reflected in the high-voltage TAC rate, it would be an increase of $0.00554/MWh (from $11.1281/MWh to $11.1336/MWh), a 0.05% increase shared by all ISO ratepayers.[11]

7 Next steps

As a next step, the ISO will conduct a conference call to discuss this revised straw proposal on September 13. The ISO then invites stakeholders to submit comments on the ISO's revised straw proposal. Comments are due September 20 and should be submitted to InitiativeComments@caiso.com.

Following review and evaluation of the comments received, the ISO will consider potential revisions to its proposal and issue a draft final proposal in early October.

[10] The ISO estimated the impact of a $9.12 million capital expenditure utilizing the existing spreadsheet model used to estimate the impact of transmission capital expenditures on the Regional (High Voltage) Transmission Access charge and employed in the 2015-2016 Transmission Plan. The assumptions are consistent with that model, and using a 10% ROE and 5% social discount rate. The impact over the first 10 years was levelized over the 10 year period, including the mid-year impact on rate base of the first year of operation. This produced an estimate of $1.17 million annual levelized revenue requirement, or 12.8% of the capital expenditure. This provides a reasonable approximation of the impact – which varies in each year due to depreciation and other impacts. $1.17 million divided by the VEA load of 544,970 MWh is $2.15/MWh.

[11] $1.17 million divided by total ISO load of 210,204,223 MWh equals $0.00577/MWh.