BAMx Comments on the 2013-14 Transmission Planning Process Preliminary Reliability Assessment Results and PTO Request Window Submissions

The Bay Area Municipal Transmission group (BAMx)[1] appreciates the opportunity to comment during the development 2013-14 Transmission Plan. The comments and questions below address the material presented at the CAISO September 25-26 Stakeholder meeting.

General Comments

High Voltage Transmission Access Charge Estimating Model

BAMX supports the CAISO efforts to post a High Voltage TAC model in October. BAMx encourages the CAISO post the model and documentation so that Stakeholders can use the model and potential prepare sensitivity analysis of the future HV TAC charge impact of some of the large projects under consideration in the 2013-14 Transmission Planning Process (TPP).

Economic Planning Studies

BAMx appreciates the description provided by the CAISO staff during the stakeholder meeting providing a comparison of study assumptions in the new simulation model and the last year's model.

The CAISO staff indicated that the simulation model takes into account the Energy Imbalance Market (EIM) modeling that is only applicable to real-time market. BAMx seeks more clarification of how day-ahead versus real-time market operations are modeled in the chronological 8,760 hourly simulations using the production cost tool that models future years.

We understand that the CAISO will evaluate economic benefits and costs of not only the Delaney-Colorado River project, but also several other projects such as, the *Harry Allen – Eldorado 500 kV line* project. During the last year's planning cycle, the CAISO's Net Present Value (NPV) calculations of the benefits of the candidate transmission projects were questionable. In our comments on the 2012-13 Transmission Plan, we conducted an exercise to demonstrate that the CAISO's calculation of the benefits based on only two years of data was highly susceptible to how the extrapolation of these benefits are calculated.[2] We encourage the

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[1] BAMx consists of Alameda Municipal Power, City of Palo Alto Utilities, and City of Santa Clara, Silicon Valley Power.

[2] For example, for the Harry Allen – Eldorado 500 kV line project, the CAISO calculated the total benefits in years 2017 and 2022 as $87M and $33M, respectively. Our understanding is that the CAISO interpolated these benefits for the intervening years and extrapolated the benefit of $33M in years 2023 onwards at 1% annual escalation. Last year, BAMx questioned the CAISO's rationale for such extrapolation of economic benefit. The CAISO had estimated the NPV of benefits over 50 years discounted at 7% to be $637M. We had verified these calculations. However, when we applied a trend on the benefits to extrapolate them beyond 2022 taking into account a significant

CAISO to seek stakeholder input into extrapolation of benefits associated with the candidate transmission projects based upon only two years of production cost studies.

Determining an Effective Mix of Non-Conventional Solutions to Address Local Needs in the TPP

BAMx supports the direction of increased reliance on Preferred Resources in this TPP. Reliance on a portfolio of Preferred Resources not only supports the environmental objectives, but also manages the risk of delay or failure of any one project through diversification. BAMx supports the CAISO's plan in the 2013-14 TPP to first model the non-conventional resource mixes in the transmission system models and then determine the remaining conventional resource and transmission mitigation needs with these potential mixes of non-conventional resources. The CAISO should develop scenarios that rely only on conventional generation and the preferred resources to meet the reliability needs. Then, it should develop transmission alternatives that reduce the level of conventional generation needed to ensure reliability. This would allow those combinations to be evaluated in Phase 4 of the LTPP to identify the least cost approach for ratepayers. BAMx is concerned that the conventional generation resources will be only considered for the residual reliability need after both Preferred Resources and new transmission development have been identified. This approach does not allow a full economic evaluation of the transmission vs. generation tradeoffs.

CAISO Reliability Assessment Results

San Francisco Bay Area – East Bay

BAMx appreciates the acknowledgement that there continue to be Category B situations in the East Bay where non-consequential load loss will occur. While PG&E has submitted a conceptual project for the Moraga-Oakland J 115 kV reconductor, there is no project proposed for this cycle, which eliminates the non-consequential load loss. We request that a mitigation to eliminate this Category B violation be included in this planning cycle.

The current base case model reflects two Oakland CTs on-line as a base case assumption. We understand that these CTs are limited in their hours of operations due to emissions restrictions. Oakland CT historical operation levels show that the CTs are not in operation or are operated very little during many months of the year, including the winter months when the load in the East Bay peaks. We understand that the CTs are also dispatched to facilitate maintenance activities in the East Bay. Additionally, these CTs are old, having been installed in 1978. Given their age, we are concerned about an over-dependence on these units through the full 10-year planning horizon. Therefore, based on their past operation, age and emissions limits, we recommend that the CAISO and PG&E consider modeling these CTs off-line in base case, but available to be paralleled and dispatched as part of system adjustment between contingencies. We also recommend maintaining the current planning practice of assuming one

drop in the benefits from 2017 to 2022, we got a NPV of benefit of $327M over 50 years, nearly half as much as benefit calculated by the CAISO.

CT fails to start when called upon. As the base case has been set for this planning cycle, we request that this change in assumptions be reflected in the 2014-15 TPP.

The reliability issues in serving the Station J area, the operating history of the Oakland CTs and the emerging issues on the Moraga-Claremont #1 and #2 115 kV lines (even with the CTs on-line), reflects the need to take a broader look at the long-term reliability in the East Bay area. Coupled with the seismic risk of an event on the Hayward fault, we believe that the CAISO's statement in the August 6 stakeholder meeting on San Francisco Peninsula Extreme Events that "TPP has not identified deficiencies in Oakland area, will consider beyond 10 year horizon in write-up" should be revisited and alternatives that can contribute to reliability in both the East Bay and the SF peninsula should be favored over those that only serve one function.

San Francisco Bay Area – San Francisco

This year's assessment again shows very high thermal overloads on the Potrero-Larkin #1 and #2 115 kV cables. (See SF-SP-T-03, SF-SP-T-06, SF-SP-T-08, SF-WP-T-04, and SF-WP-T-06 cases in this year's assessment). For several cycles the solution has been described as an action plan to transfer loads. We understand that rather than a load transfer, the proposed solution is a switching procedure at Larkin following the initial contingency. The ultimate plan is to rebuild Larkin into a BAAH configuration. As this item has appeared previously and the potential overloads are very high, what is the status of these action plans and what remains to complete the mitigation?

San Francisco Bay Area – San Jose/De Anza/Peninsula

The San Jose area contingency, SanJ-SP-T-27 (a category C5 event), shows an overload on the Trimble-San Jose B 115 kV line. We understand that this limitation is due to terminal equipment and the upgrade cost is modest. However, the upgrade was not submitted into the request window by PG&E. Will this work be included in the 2013-14 Transmission Plan?

In the DeAnza area we have previously seen some high contingency loadings on the Metcalf-Monta Vista No. 1 and 2 230 kV circuits, though they were not overloaded in the 2012-13 Transmission Planning cycle. However, when we ran the below C5 contingency on the GBA 2023SP case, we observe a 1.9% overload on the Vasona-Saratoga 230 kV section. This overload does not appear in the assessment files.

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C5_17 "Metcalf-Monta Vista No. 3 & Monta Vista-Coyote Sw. Sta. 230 kV Line "
#B2_7 "Metcalf-Monta Vista No. 3 230 kV Line "
line    30735  30705  "3 " 1    0    # line   from  METCALF     230.00  BRKR to BRKR  MONTAVIS    230.00
#B2_8 "Monta Vista-Coyote Sw. Sta. 230 kV Line"
line    30741  30705  "4 " 1    0    # line   from  CAL MEC     230.00  BRKR to BRKR  MONTAVIS    230.00
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Please include this contingency in your reliability assessment and describe your proposed mitigation in this years plan.

We understand that CalTrain has initiated a Peninsula Corridor Electrification Project (PCEP) where they will be converting the existing diesel locomotives on the Peninsula and South Bay to electric propulsion with a goal of being in operation in 2019. This is expected to add a variable load of high peak demand to the system. We also understand that the loads will be unbalanced and potentially inject harmonics into the system. Given the time horizon, consideration of these loads should be included in future TPP cycles.

PTO Request Window Project Applications

Southern California Reliability Assessment with SONGS shut down

While both SCE and SDG&E presented transmission options for potential mitigation of reliability issues associated with SONGS shut down, the potential solutions were prepared independently. Additionally, these alternatives were prepared using the initial TPP base case assumptions for Preferred Resources. Therefore, it is difficult to assess the relief provided and the potential for local resources to defer the need to large transmission expansion. Given the CAISO's role as a central transmission planning agency, we expect it to take a comprehensive approach in reconciling the generation and transmission needs within both SCE and SDG&E areas.

Southern California Edison Metro

The *Mesa Loop-In* project is presented as a mitigation to address two different T-1-1 (C3) contingencies. Loss of a 500/220 kV transformer is very rare. WECC published data indicate a failure rate of about one in 27 years (compared to once in seven months for a transmission line)[3]. That would suggest that the probability of the independent overlapping loss of two transformers would be extremely rare. Therefore, before concluding that the appropriate mitigation is the construction of a \$500M-\$700M transmission expansion, consideration should be given to less expensive measures including fire walls between transformers, system spares in addition to the on-site spare and utilizing customer interruption as a backstop measure. Since customer interruption is allowed under WECC and NERC standards for Level C events and is the mitigation used on the CAISO grid for rare but much more likely events, it should be considered for this extremely unlikely event/overlapping contingencies.

San Diego Gas & Electric Major Projects

The SDG&E proposed HV AC/DC Alternatives are very costly and have a high level of permitting uncertainty.[4] Preferred resources and local conventional generation should be considered as strong alternatives to the identified transmission expansion project. As the

[3] WECC Supporting Document for Reliability Criteria for Transmission Planning, August 1994.
[4] Recent experiences with the permitting of the Sunrise Transmission Project and the proposed Valley-Rainbow 500 kV line reflect the difficulties and delays to be expected in seeking new transmission lines into San Diego from the north or the west.

SONGS shut down is a recent event, some time will be necessary to determine whether the market for local resources is able to respond. Therefore, such transmission projects should not be immediately approved, but should be allowed to compete against a solicitation for local conventional resources. The CPUC, as part of its LTPP proceeding, would then be in a position to select an optimal solution of transmission and/or local generation. Given the urgency of the need and the long lead-time to develop transmission, early development work on the transmission alternatives may need to occur prior to the decision on local generation versus transmission. If the CPUC determines this to be the case, it may be appropriate to provide a reasonable level backstop funding for early work to maintain the transmission schedule.

The proposed Sycamore and Mission Reactive Support Projects propose to install +240/-120 MVAR of synchronous condensers at each substation. While the posted CAISO assessment identifies some minor post-SONGS voltage violations on the high voltage system, it identifies numerous voltage violations on the low voltage transmission system. Before such high voltage solutions are approved, solutions to the low voltage transmission issues should be identified. Reactive devices installed to address these issues on the low voltage systems may potentially address the few high voltage transmission violations. Additionally, if reactive compensation remains necessary after the reactive devices are installed for lower voltage issues, additional less costly additions to the lower voltage system should be evaluated. And after this evaluation, if a 230kV solution is chosen, the proposed use of synchronous condensers needs future justification. While SDG&E indicated that synchronous condensers have similar initial capital costs compared to static VAR devices, the operating costs must be considered as well. The high maintenance cost of rotating equipment and high energy losses should be considered.[5] SDG&E also identified the inertia provided by synchronous condensers as justification. However, the reliability assessment did not identify any transient stability issues that would indicate the need for additional inertia.

The Imperial Valley Flow Control project proposes to install two 500 MVA phase shifters to control the power flow between the CAISO system and the IID/CFE systems. Before deciding on a phase shifter solution, lower cost measures should be explored. These could include system arrangements such as splitting the Imperial Valley 230 kV bus to isolate the CFE and IID connections onto one 500/230 kV transformer.

Application of Planning Standards for N-1-1 Contingencies

In identifying the reliability deficiency in the LA Basin and San Diego, transmission studies have shown a widely different assessment of the reliability need depending on the Transmission Planning Criteria applied. While all analyses met the FERC/NERC mandated minimum Planning Standards, whether loss of customer load is allowed following less probable events (such as the overlapping loss of two transmission circuits) is discretionary to the local jurisdiction. There are many locations within the CAISO grid where loss of load is acceptable for such events, including an existing automatic load interruption scheme in San Diego. Also,

[5] It is somewhat ironic that SDG&E is proposing a solution that results in high steady state energy losses at the same time so much effort is being focused on increasing energy efficiency measures in the area.

given that the critical contingency driving the reliability need is for two transmission circuits that are not on common structures and have a separation exceeding the WECC minimum necessary to address common mode failure risks, the likelihood of this event during high load periods is extremely small. In such cases, planned and controlled interruption of pre-selected loads is worthy of consideration.

Therefore, as part of the development of the reliability needs for this area, public vetting and well-analyzed and supported decision-making process is necessary to establish whether and how much load shedding should be allowed in the area for such events. (Note that a decision to implement a load shedding scheme can be modified if future events warrant it; however, a decision to install large capital facilities, whether transmission or local generation, are long-lived).

Valley Electric Area (VEA) Nevada West Connect 230 kV New Line

The VEA proposed Nevada West Connect 230 kV line lacks sufficient justification for such a major transmission expansion. From a reliability perspective, the CAISO assessment identified much lower cost solutions to the identified forecasted reliability deficiencies. Such a massive transmission project is certainly not justified to address voltage issues on VEA's remote 10 MW (peak) load area in the Fish Lake area.[6] As for enhancing access to renewable energy projects to export beyond the VEA system, this must be measured against the portfolios provided by the CEC and the CPUC into the Transmission Planning Process. Also, the proposal is incomplete as the proposed project, though already very costly, does not address how the potential renewable energy would move beyond Inyo or Eldorado Substations, both of which already have identified renewable energy potential in excess of the planned transmission capacity.

Conceptual Projects

Additional information should be made available on the conceptual transmission projects envisioned by PG&E. This would provide Stakeholder an opportunity to engage in the development of these potential projects while they are still in their formative stage. BAMx members are particularly interested in concept of bring additional 230 kV transmission facilities into the San Jose area and very large projects such as the Table Mountain-Tesla Transmission Project.

The Table Mountain-Tesla Transmission Project, in part, was described as being in response to the potential loss of the CDWR loads and resources in HVAC SPS. The CAISO analysis indicated that after the transmission upgrades already approved and planned to be in place by 2018, the Path 66 transfers would not be adversely impacted for northern California hydroelectric conditions below 70 percent and only modestly impacted for hydroelectric

[6] Local voltage support or a small Static VAR Compensator (SVC) is a much more reasonable solution to local voltage issues. If additional transmission is to be considered to address this voltage issue, a 138 kV (or lower) transmission line to the SCE Inyo substation or an additional tie to NVE are much more in line with the magnitude of the problem.

generation levels up to 80 percent. While certainly additional economic analysis is necessary to assess this impact, such major transmission expansion does not appear to be justified

Conclusion

BAMx appreciates the opportunity to comment on the 2013-14 Transmission Plan Reliability Assessment Results and the PTO Request window submissions and acknowledges the significant effort of the CAISO and PTO staffs to develop this material.

If you have any questions concerning these comments, please contact
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