California Independent
System Operator Corporation

Competitive Path Assessment for MRTU
Preliminary Results for Spring and Summer Seasons

Department of Market Monitoring

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1 Executive Summary

The final path designations resulting from the Competitive Path Assessment will be used to establish the set of transmission paths applied in the two market passes of MRTU where the Local Market Power Mitigation is applied. This white paper is intended to provide information to Stakeholders and Regulatory Agencies on preliminary results of the Competitive Path Assessment along with a detailed description of modeling, data, and testing practices used in performing simulations and ultimately making competitive path designations.

This first release of CPA results evaluates two seasons, spring and summer, across three load scenarios (high, medium, and low) and three hydroelectric production scenarios (high, medium, and low). For each season and load, hydro scenario, 43 different supplier combinations are reviewed to evaluate the impact of withheld supply on the competitiveness of candidate paths. The simulation model is designed to most closely reflect the MRTU market design. A subsequent release of preliminary results will include updated network specification to keep current with the MRTU FNM specification and revised candidate path identification to reflect more current market and operational data. In addition, development is currently underway to allow for the use of security constraints in the economic dispatch algorithm.

Results for 774 one-day simulation runs are presented, 387 simulation runs each for summer and spring, along with calculation of the Feasibility Index metric and results of the competitive test for each season under two test thresholds. Using a zero-tolerance threshold where any negative FI value constitutes failure of the competitive test, in the spring scenarios 25 of 30 candidate paths failed the competitiveness test with only Imperial Valley Bank, Miguel (Import and Max Import constraints), MiraLoma Bank, and South of Lugo passing. Under the same zero-tolerance threshold, no candidate paths passed the competitiveness test under summer simulations.

It is important to note that all paths that are not candidate paths and are not "grandfathered" competitive paths (existing branch groups) are by definition deemed uncompetitive. This constitutes the great majority of transmission paths that will be modeled in MRTU.

2 Background for Competitive Path Assessment

2.1 The Role of Competitive Path Assessment in MRTU

Local market power mitigation under MRTU requires prior designation of network constraints (or paths)[1] into two classes, "competitive" and "non-competitive". Under the MRTU local market power mitigation (LMPM) procedures, generation bids that are dispatched up to relieve congestion on transmission paths pre-designated as "non-competitive" are subject to bid mitigation[2]. In its MRTU Tariff Filing, the CAISO

[1] The term path is used synonymously with transmission constraints in this context, and includes all transmission constraints that are enforced in Pass 1 and Pass 2 of Pre-IFM. A path is by definition directional.
[2] A detailed description of the MRTU LMPM procedures can be found in the MRTU Tariff and MRTU Business Process Manuals on the CAISO web site at http://www.caiso.com/docs/2001/12/21/2001122108490719681.html.

proposed to designate all of today's existing zonal transmission branch groups as "competitive" and undertake a study prior to MRTU implementation to determine whether additional transmission paths could be designated as "competitive" for day one of MRTU. Thereafter, the CAISO proposed to reevaluate path designations on an annual basis or sooner if system or market conditions changed significantly[3].

LMPM in MRTU will be applied in a two-step process that is used to identify specific circumstances where local market power exists. This process occurs just prior to running the market (day-ahead or real-time) and applies mitigation to resources that have been identified as having local market power. All transmission facilities that are modeled in the full network model (FNM) have a designation of "competitive" or "non-competitive". The first step of this process applies clears supply against forecast demand with thermal limits enforced only on the set of competitive constraints (the "Competitive Constraint Run (CCR)"). This provides a benchmark dispatch that reflects competition among suppliers since only those transmission constraints deemed competitive are applied in the network model. The second step applies all constraints, competitive and non-competitive, and re-dispatches all resources to meet forecast load. In this second step, the "All Constraint Run (ACR)", some resources will be dispatched further up (compared to the CCR) to relieve congestion on the non-competitive constraints now that they have been applied in the market solution. Those resources that have been dispatched up in the ACR relative to the competitive benchmark dispatch from the CCR are deemed to have local market power since they were needed to relieve congestion on a non-competitive constraint and will have their bid curve mitigated to their Default Energy Bid from the CCR dispatch point to the full bid-in output for that resource.

The Competitive Path Assessment is based on a Feasibility Index (FI) methodology that was developed through an extensive stakeholder process in 2005. Alternative approaches, including those used by PJM and MISO, were considered and reviewed at Stakeholder Working Group meetings held in the latter part of June through mid-July 2005. Among all the options considered, the FI methodology had certain conceptual advantages as well as the greatest support within the Stakeholder Working Group and thus was the approach adopted and filed with FERC.

Over the past year, DMM has developed the modeling tools and input data for conducting the CPA and has completed some initial demonstration results. This draft report provides a review of the study approach and demonstration results. The draft report will be shared and reviewed with stakeholders in order to solicit input and recommendations on potential refinements to the methodology and presentation of results. It is important to note that this set of results are preliminary and that additional updates, including candidate path identification and network model specification, will be completed in addition to publishing a full set of seasonal results prior to finalizing results.

[3] Specifically, the CAISO may perform additional competitive assessments during the first year if changes in transmission infrastructure, generation resources, or load, in the CAISO Control Area and adjacent Control Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes.

A detailed description of the FI methodology is provided in the next section. This is followed by a review of the various modeling assumptions and input data. The demonstration results are provided next. The report concludes with a discussion of next steps for further refinements and modifications.

3 The Feasibility Index Methodology

Transmission constraints increase the potential for exercising market power by raising the level and decreasing the elasticity of effective demand curves facing generators. There are several distinct types of market power opportunities that transmission constraints can present. The most familiar is high concentration of supply within load pockets. In that case, by withholding capacity, local generation can induce congestion on connecting paths, creating an uncompetitive situation for the residual demand in that location. Another example involves the interaction of generation controlled by a single supplier in different parts of the network; in certain situations, market power can be exercised by pricing a generator at one location below marginal cost at one location in order to deliberately create congestion that raises prices for other generators at other locations.[4]

The focus of competitive path analysis is the identification of transmission constraints that result in the first type of uncompetitive conditions: high concentration in the supply-deficit areas. This is arguably the most prevalent and well-known set of market power problems caused by transmission.

Pivotal supplier analysis is central to competitive path assessment. It is a common feature of the MISO and PJM methodologies, although those ISOs have different methods of determining the relevant supply and demand for pivotal supplier analysis. They both use generation shift factors, but their choice of the slack bus(es) for determination of generation shift factors is different. In general, and specifically in both cases of MISO and PJM, the choice of the slack bus(es) for determining the shift factors is rather arbitrary and has a potentially important impact on the outcome of the pivotal supplier analysis. The Feasibility Index methodology used here addresses the pivotal supplier analysis without the need to designate a slack bus(es) for the determination of the shift factors. In fact, the FI approach does not even use the shift factors. This is advantageous, because the choice of shift factors will always be somewhat arbitrary, and the location of the INC (DEC) that matches the assumed DEC (INC) of a resource in question will depend on system conditions and economics. An additional advantage of the proposed method is that the method is comprehensive, in that it considers the interacting effect of all constraints at once.

The methodology for competitive path assessment starts by selecting one or more representative system conditions, load levels (and load distribution), and supply resources that would normally be available (not on forced or maintenance outage) under the assumed seasonal conditions. For a given set of load, network, and supply conditions, the question is whether there are pivotal suppliers in the sense that without

[4] J. Cardell, C.C. Hitt, and W.W. Hogan, "Market Power and Strategic Interaction in Electricity Networks," *Resource and Energy Econ.*, *19*(1-2), 1997, 109-137.

their combined supply participation congestion will exist and cannot be resolved on the path in question (and thus some load would potentially be unserved in some local area). If there are such pivotal suppliers, the path in question is non-competitive under the given set of conditions.

The general concept underlying the FI methodology is to take out all supply resources of one or more specific suppliers and determine if the remaining suppliers' resources can be scheduled to meet the load subject to the transmission constraints, i.e., if a feasible solution exists with the remaining supply. This is done simultaneously for the entire system's set of loads, resources, and transmission facilities. In case a feasible solution does exist, the supplier(s) in question are not pivotal for congestion relief on any path under the set of supply/demand/system conditions. Otherwise the supplier(s) in question are pivotal for congestion relief on the paths that cause solution infeasibility.[5]

To identify those paths and quantify the relative degree of infeasibility each cause, we define a "Feasibility Index" (FI) for each transmission constraint with respect to each supplier. To define the FI index, we modify the production cost optimization, which is base on a Full Network Model of the CAISO Control Area, by treating all non-grandfathered transmission constraints as soft constraints with very high penalties (orders of magnitude higher than the highest bid price or the prevailing bid cap) for violating the constraint. Thus, instead of getting no solution, we would get a "least cost" solution in which some transmission flows exceed the transmission (constraint) limit. As discussed earlier, the current inter-zonal branch groups are considered "competitive" and therefore are enforced as hard constraints in the optimization.

For a single supplier i whose resources are removed, we define the Feasibility Index (FIij) of Path j with respect to Supplier i as follows:

Let

Limit (j) = Transmission Limit on Path j

Flow (i,j) = Power Flow on Path j without Supplier i's Resources (with soft limits)

Then

FI (i,j) = [Limit (j) - Flow (i,j)] / Limit (j)

If FI (i,j) is negative, supplier i is pivotal for congestion relief on the system, in particular on Path j. If FI (i,j) is positive, supplier i is not pivotal for congestion relief on Path j (in combination with the other constraints), but if FI (i,j) is small, it is possible that the supplier j could be jointly pivotal with another supplier k having a small feasibility index FI (k,j) on the same path j. This provides for an easy selection of candidate suppliers for two or more jointly pivotal suppliers test if no single supplier is pivotal on Path j. The

[5] This is equivalent to the effective demand curve for the supplier's generation becoming vertical at some positive quantity at some location. Therefore, it is appropriate to view competitive path analysis as simply being a logical generalization of pivotal supply analysis to a market with transmission constraints. An important implication is that methods based on complex manipulations shift factors and which don't consider all interacting constraints (such as the MISO approach) may actually fail to identify all situations where a generator is pivotal due to transmission constraints. This can be shown on simple two node networks.

pivotal supplier criteria that the CAISO adopted and filed with FERC is a "no three pivotal supplier" criteria (i.e., candidate paths that have a negative FI when any three or less suppliers are removed from the market are considered "non-competitive").

The following generic matrix demonstrates the single pivotal supplier test results for n candidate paths. Table 1 shows a matrix of Feasibility Index results for n candidate paths (P1 – Pn across the top of the matrix) with various suppliers removed from the model (individually). In this case, the sign of FI(i,j) indicates whether supplier i is pivotal with respect to any of the candidate constraints.

Table 1. FI Matrix

Paths ⇨ Suppliers ⇩	P1	P2	…..	Pj	….	Pn
S1	FI(1,1)	FI(1,2)				FI(1,n)
S2	FI(2,1)	FI(2,2)				FI(2,n)
.						.
Si				FI(i,j)		FI(i,n).
.						.

If a FI(i,j) entry is negative for any Supplier i, Path j is non-competitive. If all FI(i,j) entries are positive for Path j, but some are small (below a designated threshold), then the test is repeated with the supply resources of both suppliers removed. The test will be repeated again when the supply resources of three suppliers removed if all FI(I,j)n entries are positive for path j if two suppliers' resources are removed.

For any candidate path that shows FI < 0 for a specific test case (supplier combination removed, load scenario, hydro scenario), that path it is designated *Non-Competitive* for purposes of applying LMPM in MRTU. Such a designation means the path limit will not be enforced in the CCR an will be enforced in the subsequent ACR where identification of local market power is performed.[6] Any candidate path that has FI ≥ 0 under all test conditions is designated *Competitive* form purposes of applying LMPM in MRTU and the thermal limit for that candidate path will be applied in both the CCR and ACR where LMPM is performed.

[6] See prior section for description of CCR and ACR in the context of applying LMPM.

4 Implementation of the FI Methodology for MRTU

4.1 Simulation Methodology

The simulation follows the basic power flow concept and is being developed to most closely match the market design and optimization that will be used in MRTU. Simulations for this round of preliminary CPA results were performed in PLEXOS.[7] Specifically, the CPA simulation includes the following features:

- Unit commitment: An inter-temporal optimization is used that selects resources to be committed over the single day (24 hour) simulation period based on their start-up, minimum load, minimum run time, and energy bids (cost-based in this simulation) compared to potential revenues available to that resource if committed across some or all of the hours in that day. The approach applied in this simulation is the Rounded Relaxation (RR) algorithm. The primary reason for using this approximation (compared to mixed-integer algorithm) is its computational efficiency, which is important in light of the number of simulations that must be run to reflect the various supplier combinations withdrawn from the model and the various load and hydro scenarios.

- Co-optimization of Energy and Ancillary Services: The simulation co-optimizes unit commitment, energy procurement, and ancillary service procurement. AS prices in MRTU will reflect both the capacity price for the service as well as the opportunity cost for energy. Because the CAISO does not have a cost basis for AS capacity bids, a capacity price of zero is used in the simulation and only the opportunity cost of selling AS is reflected in the optimization.

- Transmission Constraints: Simulation models inter-zonal transmission interface (branch groups) limits as hard constraints, and all other transmission facility limits, such as individual transmission lines and candidate paths, as soft constraints (as described in the FI methodology section) with a penalty price of $50,000/MW for constraint violation.

- Penalty for Dropped Load: A penalty price of $1,000,000/MW/hr is used for load curtailments. This (relatively) high penalty price, along with the $50,000/MW/hr transmission constraint penalty price, insures that no reasonable economic substitution would take place between the options of dropping load, dispatching additional generation, and violating a transmission soft constraint. It allows the simulation model to find solutions with dropped load in cases when the amount of load at some nodes within a region or regions could not be met since too much generation capacity is removed from the region/regions and the importing capabilities from adjacent/nested control areas are restricted by branch group hard limits.

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[7] Additional information on PLEXOS is available at http://www.energyexemplar.com/main.asp?page=overview.

- Economic dispatch with optimal power flow (DC-OPF) that mimics the MRTU DA market process. Note that the DC-OPF approach does not explicitly model losses or reactive power flows. To account for losses, total load is scaled by an aggregate loss factor prior to being distributed to the load busses, implicitly factoring losses into the simulation.

- Zonal Ancillary Service Procurement: Ancillary services are procured with zonal requirements enforced, where an approach of "concentric" zones is used when requirements are overlapping. The simulation, however, does not explicitly account for AS procurement from outside the CAISO control area due to limitations in the simulation software for reserving transmission on the inter-ties for the potential import of energy from AS procured outside the control area. To account for AS imports, an implicit approach was taken where a portion of the total (calculated) AS requirement is assumed to come from imports based on historical procurement, so that (a) the total AS requirement is adjusted down to account for historical AS imports and (b) individual interface (Branch Group) transmission capacities are reduced by the seasonal historical seasonal hourly average AS imports across those interfaces. The simulation model only procures the upward regulation services (i.e. no Regulation Down) since procurement of downward reserves would not impact the feasibility of the power flow model with any amount of capacity removed.

At the time these results were prepared, the size of the network model combined with a representative list of contingencies that will be considered in the MRTU optimization routine comprised an optimization problem that was too large for the simulation software to solve on a desktop computer for all scenarios and withdrawn supplier combinations considered. This precluded the use of multiple contingency-based Security Constrained Unit Commitment (SCUC) and Dispatch in the optimization routine for the simulations used in the preliminary CPA results presented in this paper. Thus, only the constraints enumerated above were imposed. A revised approach to incorporating into the simulation software an SCUC option is currently under way. The goal of this effort is to reduce the memory requirement of the optimization when SCUC is enabled so that the optimization problem and can be solved consistently on desktop computers. If this effort is successful, the next release of preliminary CPA results will include the SCUC feature in the simulations.

4.2 Network Model

The network model used for the final competitive path assessment studies will be very similar to the proposed full network model (FNM) that will be used in the MRTU Day-Ahead Market. For the preliminary analysis presented here, the network model used for the competitive path study is the same as the Congestion Revenue Rights Full Network Model (CRR FNM) that the CAISO released to market participants starting October 30, 2006. This CRR Base PSS/E Network Model (Bus Branch) is based on the Local Capacity Requirement 2007 summer base case. This base case was developed with the intention to be as consistent as possible to the proposed FNM that will be used in the MRTU Day-Ahead Market. The CAISO utilized the GE PSLF program to reduce the network in the initial full LCR 2007 case and export it to a reduced network case in PTI

PSS/E format for use in CRR Dry Run. The CRR model was tested in PTI version 26, and solved a power flow. The CRR FNM was then imported into the simulation model for this initial competitive path assessment effort.

Along with the CRR FNM, related data such as thermal branch limits, source and sink names along with the mapping to the FNM, corridor and nomogram/interface constraints were also imported into the simulation model. This data is consistent with the data the CAISO will use in the CRR Dry-Run Allocation and Auction processes (i.e., in the simultaneous feasibility test (SFT) processes) as well as other MRTU processes (i.e., in the Day Ahead Market). The thermal branch limits data is comprised of the summer thermal limits (normal and emergency MVA limits) for a selected set of branches[8]. For the competitive path assessment study, similar to the CRR Dry-Run, we only enforced normal thermal branch limits for branches with both ends at 60kV or above and that reside completely within the CAISO control area (thus, tie lines are excluded).

The nomogram/interface constraints were enforced with the simultaneous flow limits that the CAISO currently anticipate enforcing in the MRTU markets. The same weighting factor for each line or transformer that makes up the constraints in the CRR FNM are also incorporated in the CPA simulation model.[9]

More specifically, all of the 5,191 transmission lines/transformers, 3,929 buses, 44 inter-zonal interfaces, and 57 local area constraints from the CRR FNM are imported into the simulation model for this initial competitive path assessment study.

4.3 Grandfathered Competitive Paths

According to the competitive path methodology filing, all CAISO's current inter-zonal interfaces (i.e., branch groups) are considered grandfathered competitive paths and will be applied as hard constraints (i.e., un-relaxable constraints) in the simulation. Table 10 shows the current inter-zonal branch groups and the Operating Transfer Capability (OTC) limits on both imports and exports directions that are incorporated in the current competitive path study network model (for the Spring base case simulation). These branch group definitions are updated to reflect the latest Network Model (Feburary 2nd 2007 release) available on the CAISO website[10].

4.4 Additional Transmission Limits

In addition to the transmission interfaces discussed above, additional transmission constraints, the same as in the CRR FNM, are included in this model and modeled as soft constraints for the competitive path assessment. Some transmission constraints define import/export limits to area within existing congestion zones, such as the San

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[8] Note that the thermal branch limits are scaled by a factor of 97% to account for losses and additional factor of 97% to account for reactive power since the CRR FNM is a lossless DC FNM. The effect is to reduce thermal limits by just under 6%.

[9] The CPA, CRR, and MRTU applications will be using the same FNM, albeit versioned depending on the FNM available at the time the application requires it. The FNM is available to market participants and their agents through the CRR Dry Run process and requires signature of a Non Disclosure Agreement. Please refer to the CAISO web site for more details on obtaining the FNM for the CRR Dry Run.

[10] The branch groups definitions can be obtained from http://www.caiso.com/1b69/1b699ec512e60.xls

Francisco, Fresno, and North Bay areas, while others limit network flows but do not surround geographic areas, such as Miguel substation in San Diego, Vincent substation, and simultaneous flow limits within the Bay Area. In addition to all individual line/transformer limits at 60 kV and higher voltages and interfaces, the transmission constraints used in this study include the transmission constraints listed below.

Area Import Limits

a) Humboldt import limits,
b) North Geysers area import/export limit, and
c) South Geysers area import/export limit,

Regional Import Limits

a) Southern California Import Transmission (SCIT).

Pacific Gas and Electric Area

a) Pittsburg to San Mateo_ East Shore,
b) Contra Costa 230 kV import,
c) Tesla to Pittsburg,
d) Tesla – Delta Switchyard,
e) Tesla – Manteca,
f) Moss Landing to Metcalf,
g) North of Martin,
h) Oakland 115 kV,
i) Sobrante – Grizzly – Claremont,
j) Metcalf – El Patio,
k) Pittsburg bank,
l) Metcalf – Morgan Hill,
m) Llagas – Gilroy,
n) Humboldt bank,
o) Rio Oso – Drum,
p) Palermo – Colgate,
q) Palermo 115 kV,
r) Table Mt. – Rio Oso,
s) Table Mt. – Rio Oso & Palermo,
t) Bogue Area Import,
u) Colgate 60kV,
v) Monta Vista – Jefferson,
w) Ravenswood -San Mateo,
x) Ravenswood Cutplane,
y) Tesla Banks 6 & 4,
z) Keswick – Cascade,
aa) Loss of Bridgeville – Cottonwood,
bb) Loss of Trinity – Cottonwood,
cc) McCall – Sanger – Reedley;
dd) Placer – Gold Hill #2,
ee) Schulte – Kasson,

ff) Schulte – Kasson & Tesla,
gg) Panoche – Kearney & Gates – Gregg,
hh) Gates – McCall & Helm – McCall,
ii) Gates 230 kV,
jj) McCall banks 2 & 3, and
kk) Corcoran – Kingsburg.

San Diego Gas and Electric Area

a) North of SONGS,
b) South of SONGS,
c) Miguel max import,
d) Miguel import,
e) SDG&E & CFE import,
f) SDG&E import,
g) El Centro bank, and
h) Imperial Valley Bank.

Southern California Edison Area

a) South of Lugo,
b) Antelope – Vincent,
c) Vincent bank,
d) South of Magunden,
e) Mira Loma bank,
f) Serrano bank, and
g) Serrano – Orange County.

4.5 Assumptions About System Conditions

4.5.1 Demand Forecast

The essence of this initial study is to assess the competitive paths using a wide range of system supply and demand conditions. For this purpose, we construct three demand forecast scenarios as follows. First, actual 2006 loads for the PG&E, SCE, and SDG&E transmission areas have been obtained from telemetry data. From this data, a seasonal CAISO system-wide daily peak load duration curve is created to represent the 2006 peak load condition in that season. Three load scenarios are chosen for each season by selecting individual days within a season that correspond to specific points on the daily peak hour load duration curve for that season. Currently, the high, medium, and low load scenarios are chosen based on the 95th percentile, 80th percentile, and 65th percentile respectively for the daily peak hour load duration curve for each season.

For example, the summer season has 92 daily peak values, one for each day during July, August, and September. A cumulative distribution is calculated for these daily peak load values during the Summer of 2006, and the low, medium, and high load scenarios for Summer 2006 are identified by the three individual days where 95%, 80%, and 65% of daily peak load values are below the load value for those days. These three days are identified as July 26, July 15, and August 24 respectively. The following table summarizes the days identified for various load scenarios in each season:

Table 2. Selection of Typical Day for Seasonal Load Scenario

Load Scenario	Spring	Summer	Fall	Winter
High	6/23/2006	7/26/2006	10/23/2006	1/9/2006
Medium	6/4/2006	7/15/2006	10/19/2006	2/1/2006
Low	5/11/2006	8/24/2006	10/20/2006	3/21/2006

The following table shows the assumed CAISO system daily peak load for various load scenarios in each season for this initial study:

Table 3. System Daily Peak Load for Three Load Scenarios by Season (MW)

Load Scenario	Spring	Summer	Fall	Winter
High	41,971	47,604	32,430	31,407
Medium	35,362	42,637	31,628	31,062
Low	33,279	40,611	31,108	30,784

Since the loads calculated from telemetry data are actually the sum of loads plus losses, the estimated losses of 5% have been subtracted to produce local area loads without losses at the take-out points to accommodate use of lossless DC-OPF simulation approach. The lossless simulation approach is adopted specifically to ensure that losses do not interfere with the violation of soft transmission constraints on the candidate (and non-candidate non-grandfathered) paths. Fixed load distribution factors from the CRR FNM are incorporated in the model.

4.5.2 AS Modeling and AS Requirements

Co-optimizing AS and energy in the DA market is an important feature of the CAISO's new market design. In the MRTU DAM, suppliers can provide both energy bids and AS bids and DAM will procure 100% of the requirements. AS requirements are closely related to load forecasts. In this initial competitive path assessment study, a simplified AS and energy co-optimization process is adopted. First of all, unlike the 10 AS regions that will be considered in the Release 1 of MRTU DAM[11], we simply consider two AS regions: System, and South of Path 26 (SP26), because these two are the most important AS regions based on the ISO historical operation experiences. The minimum requirements for each of these two AS regions are calculated using the following rules:

System AS Region:

[11] The 10 AS regions implemented initially for MRTU Release 1 are: Expanded System, System, South of Path 15, Expanded South of Path 15, South of Path 26, Expanded South of Path 26, North of Path 15, Expanded North of Path 15, North of Path 26, Expanded North of Path 26.

- Regulation Up (RU) Minimum Requirement: 450 MW
- Operating Reserve (OR) Minimum Requirement: 7% of system load minus historical DA final OR imports to CAISO

SP 26 AS Region:

- Operating Reserve (OR) Minimum Requirement: 40% of (7% of system load) minus historical DA final OR imports to SP26.

Note again that AS requirements are correlated with load forecast scenarios in this study. For example, the summer high load scenario day is identified to be August 16, 2006. Thus the hourly system OR requirement corresponding to the high load scenario is calculated as 7% of the hourly system load (from August 16, 2006, load data) less the hourly DA final OR imported to the CAISO control area on that day.

The following table shows assumption for the system and SP 26 regional minimum operating reserve requirements in various seasons under various load scenarios at the daily peak hour:

Table 4. Minimum Operating Reserve Requirement at Daily Peak Hour (MW)

Load Scenario	Region	Spring	Summer	Fall	Winter
High	System	2,678	3,109	2,168	2,005
	SP 26	1,024	1,271	830	728
Medium	System	2,214	2,815	2,112	1,980
	SP 26	831	1,152	809	724
Low	System	2,070	2,611	2,068	1,947
	SP 26	805	1,074	802	727

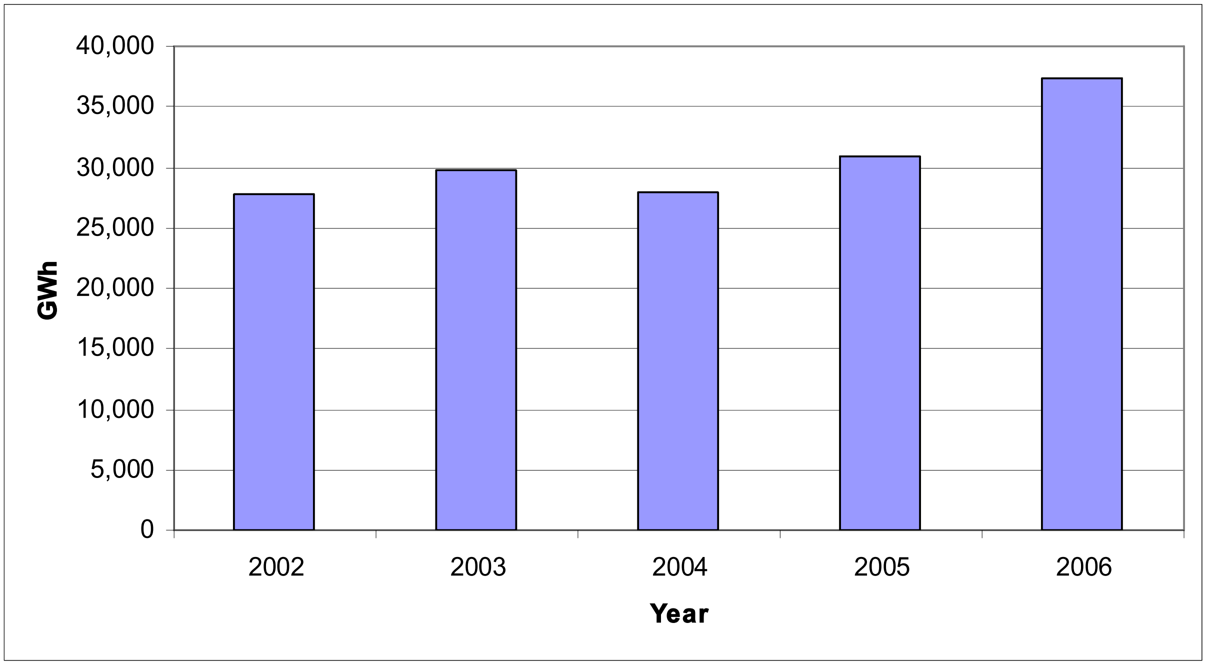
Generation units that are certified for providing RU and OR are identified using the CAISO internal database and their maximum capabilities for providing RU and OR are calculated using their historical bid quantities. Bid prices are assumed to be zero as a simplification to the MRTU DAM so that there will be no capacity pricing for the service and only the opportunity cost (of not selling AS capacity as energy) of providing reserve is calculated during the optimization process[12]. In other words, the market would at least have to compensate the generation unit providing AS for the profit forgone in the energy market.

4.5.3 Prediction of Hydroelectric Generation

Three hydro scenarios (wet, medium, and dry) will be simulated based on California's historical hydroelectric production data for the purpose of preparing DAM bids for hydro units. The chart below shows the hydroelectric production level of hydroelectric resources within the CAISO control area from 2002 through 2006.

[12] Non-zero AS bid prices essentially reflect the desired additional compensation to cover, for example, the cost of operating generation unit at lower efficiency to provide reserve, i.e., a premium on top of opportunity cost for providing AS.

Figure 1. Annual Total CAISO Hydroelectric Production



From Figure 1 we see that 2004 is a low hydroelectric production year, 2005 is a medium production year, and 2006 is a high production year.

After the low, medium and high hydro years are identified, a hydro daily production duration curve was constructed for each season and each year. The 95th percentile date was then determined in each season as the hydro scenario date for the actual 24 hour simulation. Table 5 summarizes the days identified for various load scenarios in each season.

Table 5. Selection of Typical Day for Seasonal Hydro Scenario

Hydro Scenario	Winter	Spring	Summer	Fall
4.5.3.1.1 High	3/23/2006	5/19/2006	7/3/2006	11/30/2006
Medium	3/30/2005	5/25/2005	7/7/2005	12/26/2005
Low	3/19/2004	4/15/2006	7/16/2006	12/13/2006

The identification of hydro scenarios is again solely for the purposes of preparing hydro generation bids, pump storage facility bids and intertie import/export bids. Simulating hydro generation units' optimal bids with regard to hydro resources' energy limits and other constraints is beyond the scope of this study. In the section below we will discuss how we construct bids for hydro generation units that reasonably reflect hydrology conditions as well as the opportunity cost of hydro production.

CAISO control area import and export patterns are highly affected by the hydrology conditions not only within California, but in the Pacific Northwest as well. Hydrology conditions can be consistent across the west coast, and in the CAISO control area inter-tie bids are generally correlated with hydro scenarios. In the next section we will also discuss how we construct inter-tie import and export bids that are consistent with the hydro condition in the west coast.

4.5.4 Internal Supply

Supply can be broken out into the following categories: gas fired non-peaking generation, peakers, nuclear, hydroelectric/pump storage units, and qualifying facilities (i.e. wind, solar, geothermal, biomass, and cogeneration).

4.5.5 Gas Fired Non-peaking Generation

The model contains 85 thermal units with installed capacity of roughly 25,400 MW, including new generation that has come online over the past few years. In the CPA simulations, all gas fired non-peaking units bid their marginal cost (plus an adder for variable operating and maintenance cost) as determined by the unit's heat rate and natural gas prices. The incremental heat rates are calculated from latest average heat rate data stored in CAISO master file database. The "Option 2 cap with average heat rate" method is adopted in incremental heat rate calculation (more information about this method can be found elsewhere[13]). Other unit characteristics that are included in the economic dispatch process are minimum stable level, start up cost, minimum up and down time, and maximum ramp up and ramp down rates. Gas fired non-peaking generation units are fully optimized in terms of a 24-hour unit commitment and hourly economic dispatch.

The minimum stable level, heat rate, start up cost, minimum up/down time, and ramping rates for these units are all obtained from the CAISO internal database and the gas price forecast is obtained from the 2006 history data and will be discussed in the later section.

4.5.6 Peakers

There are 61 peaking generation units included in the model with total installed capacity roughly 10,900 MW. Similar to thermal units, all peakers are assumed to bid their marginal cost for energy, start up cost for unit commitment, and the following physical operation parameters as reported to the CAISO: minimum up/down time, and maximum ramp up/down rate. Peakers are also fully optimized in terms of a 24-hour unit commitment and hourly economic dispatch.

4.5.7 Nuclear

There are four nuclear generating units (two San Onofre units and two Diablo Canyon units) included in the model with installed capacity of 4,450 MW. Bid quantities for nuclear resources are based on actual metered output for selected load scenario date described in Table 3. The bid price for nuclear resources is $0/MWh. Unit commitments

[13] http://www.caiso.com/1ba0/1ba0885c5fea0.pdf

for nuclear resources are predefined according to their actual metered output and are not determined by the simulation software.

4.5.8 Hydroelectric Generation and Pump Storage Units

There are 197 hydroelectric and related dispatchable resources included in the model.

Hydroelectric resources are committed and dispatched by the simulation software in the CPA. Bids are determined by two factors for these resources. First, the resource's final hour-ahead schedule for the chosen hydro scenario date in Table 5 is used to create the first bid segment at a price of $0/MWh. Second, the resource's real-time offer quantity is used for the second step of the bid curve, with the bid price for this second step calculated as the quantity-weighted average bid price from bids for that resource on the selected hydro scenario date. The two segments are combined together to form the final bidding quantity and price for hydro units. If a hydro unit has neither hour-ahead schedule nor real time bids in the historical data for the identified hydro scenario year, no capacity is offered by that resource in the simulation.

Five pump storage units are considered in the model.

The generation of each of the pump storage units is already included in the hydro units' offer quantity/offer prices, as described above. The load side of the pump storage units is modeled as an energy purchaser in the simulation software, or in effect, as load resources that buy energy from the pool. Each pump storage unit has a 2-step demand curve. For the first step of the demand curve, bid quantity is calculated as the final historical hour-ahead load schedule with a $5,000/MWh bid price which makes this bid segment a price-taking load bid segment. The second step of the pump-load bid curve has total real-time historical bid quantity for the quantity portion and the quantity-weighted average bid price for the price component. Similar to hydro units, if a pump storage unit does not have historical data for the identified hydro scenario years, that resource will not be bid into the simulation model.

4.5.9 Qualifying Facilities

Qualifying Facilities (QF) include wind, solar, geothermal, biomass, and co-generation units. Basically all the remaining internal units fall into this category. All QF units are assumed to bid in their actual 2006 (metered) generation level with zero price (i.e., self schedule). The same load scenario dates are used to construct their self-schedules.

4.5.10 Imports and Exports

Imports are not considered pivotal in this analysis: that is, no import resources are deleted in any of the CPA simulation runs. External resources are modeled using their historical inter-tie bids at various scheduling tie-points. A tie-point connects a node inside the CAISO to a node outside of the CAISO. Each tie-point's outside node is considered to be both a generation node (for the purpose of modeling imports to the CAISO) and a load node (for the purpose of modeling exports from the CAISO).

Since hydro conditions and imports/exports are highly correlated, inter-tie bids are constructed using actual data from the specific hydro scenario dates. A multi-step bid curve is established for imports and exports across each tie-point separately using the approach described for hydroelectric resources (imports) and pump load (exports). Since more than one Scheduling Coordinator can submit their bids on each tie-point, all the historic hour-ahead schedules and real-time bids are grouped on the tie-point level and uniformly divided into a standard 11-segment format according to the aggregated prices curve. Note that the $5,000/MWh price is to ensure self-scheduled export will be dispatched in the simulation.

4.5.11 Dynamic Schedules

Dynamic schedules are modeled in the same fashion as hydroelectric resources.

4.6 Generation Ownership

This study focuses specifically on the impact of withdrawn capacity by the seven largest owners of installed generation capacity in the CAISO control area who are net sellers. Note that net buyers in the CAISO control area are excluded from consideration as potentially pivotal suppliers since they are less likely to benefit from increasing prices through withholding supply. The installed capacity and generation concentration for the seven suppliers considered are listed in Table 6.

Table 6. Suppliers Considered and Their Generation Capacity Concentration Areas

Supplier	CAISO Zone	Installed Capacity (MW)	Percent of Zonal Capacity
S1	NP26	4,182	21%
	SP26	751	3%
S2	SP26	3,976	16%
S3	SP26	2,582	11%
S4	NP26	2,347	12%
S5	NP26	1,300	7%
S6	NP26	595	3%
	SP26	1,101	5%
S7	SP26	1,148	5%

The top three suppliers with installed capacity in NP26 area are S1, S4, and S5. The top three suppliers with installed capacity in SP26 area are S2, S3, and S7. For the CPA study, the FI values are calculated for candidate paths for all combinations of up to three of these six suppliers, where the capacity of the supplier combinations is removed from the simulation model either individually or jointly. In addition, we also consider two cases where only the capacity owned by S6 is withdrawn from the model supply. The total number of supplier combinations (for capacity withheld) for any one season, load scenario, and hydro production scenario is 43.

For each season, there are three load scenarios and three hydro scenarios. The total number of simulation runs for each season is 387 (43 supplier combinations * 3 load scenarios * 3 hydro production scenarios = 387)

For this release of CPA results, only spring and summer seasons are evaluated. The total number of simulation runs is 774 (2 seasons * 387 simulation runs / season = 774).

4.7 Natural Gas Prices

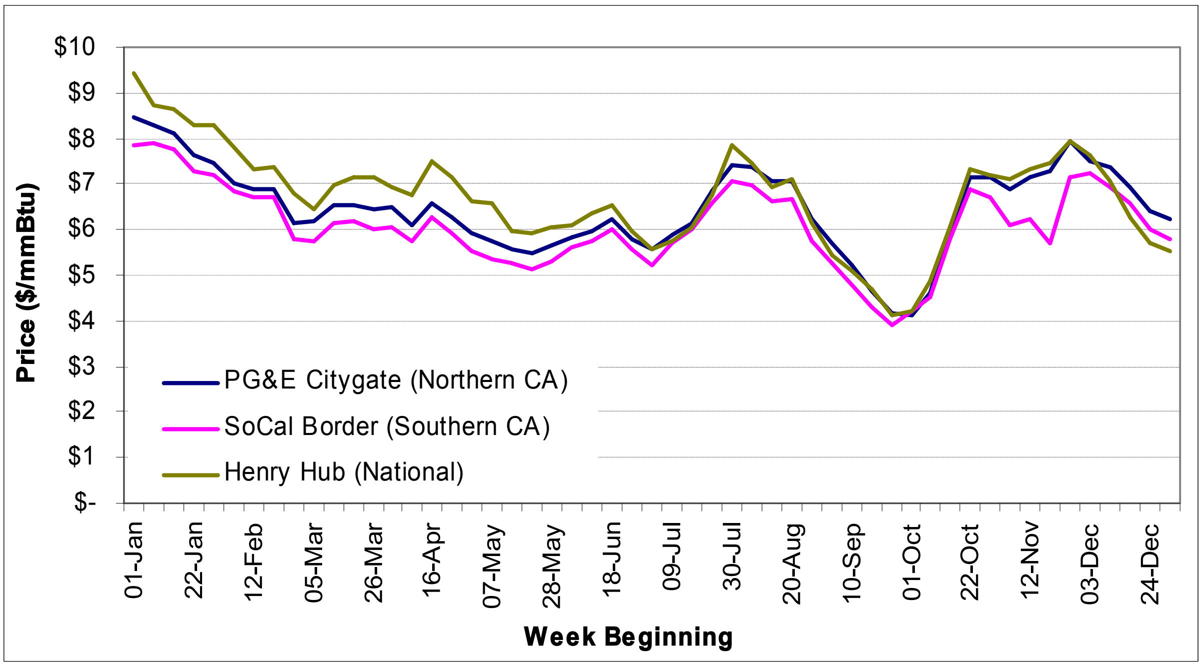
Natural gas prices are required to calculate the cost-based bids for thermal resources which have heat rate data in CAISO master file database. The values used in the simulations for this CPA are seasonal average natural gas prices for the northern and southern regions of the CAISO control area in 2006.

Table 7. Seasonal Natural Gas Prices by PTO Region

Season	PG&E	SCE	SDG&E
Winter	$7.13	$6.78	$6.78
Spring	$5.99	$5.67	$5.67
Summer	$6.09	$5.75	$5.75
Fall	$6.65	$6.16	$6.16

The following chart shows the actual nominal natural gas price in the CAISO control area for 2006.

Figure 2. Weekly Average Natural Gas Prices for 2006



4.8 Generation and Transmission Outages

For this preliminary study, we assume all thermal and peaking units are available for commitment and dispatch between Pmin and Pmax, subject to minimum up/down time and ramp rates. In other words, planned and forced generation outages are not modeled for thermal and peaking units. The availability of all hydro units and QF units are determined either by their historic hour-ahead schedule level plus real-time bid level, or determined by the historic production level, thus they may incorporate historical pattern of planned and forced outages to some degree.

Incorporating of transmission outages has been limited in this preliminary study and the status of transmission lines/transformers are kept consistent in this study as the CRR FNM.

4.9 Identification of Candidate Competitive Paths

In theory, the list of candidate competitive paths could include all paths. However this would be an inefficient way to identify candidate competitive paths since 1) data analysis would be extremely complicated and voluminous and, 2) paths that are infrequently congested would not be creating local market power opportunities and therefore not triggering any bid mitigation and thus assuming these paths are non-competitive would not result in over-mitigation. Therefore we focus instead on paths that have experienced significant intra-zonal congestion in the past. List of frequent congested intra-zonal paths can be divided into the following two categories:

1. Frequently congested paths identified by high RMR dispatches incurred in real-time as RMR units are the first to be dispatched to relieve intra-zonal congestions; and
2. Frequently congested paths identified by high re-dispatch costs (OOS) incurred in real-time if the RMR dispatches are not sufficient to alleviate the constraints.

After extensive analysis, we have identified the following intra-zonal interfaces as candidate competitive paths:

Table 8. Summary List of Candidate Competitive Paths

Candidate Path	Candidate Path
Bogue Area Import	Oakland 115kV
Colgate 60 kV	Palermo - Colgate
Humboldt Bank	Palermo 115kV
Humboldt Import	Pittsburg Transformers
Imperial Valley Bank	Pittsburg to San Mateo_E. Shore
Llagas to Gilroy	Ravenswood Cutplane
Metcalf to El Patio	Ravenswood to San Mateo
Metcalf to Morgan Hill	Sobrante - Grizzly - Claremont
Miguel Import	South of Lugo
Miguel Max Import	Table Mt - Rio Oso
MiraLoma Bank	Table Mt - Rio Oso & Palermo
Monta Vista - Jefferson	Tesla - Manteca
Moss Landing to Metcalf	Tesla Banks 6 & 4
North Geysers Import	Tesla to Delta Switchyard
North of Martin	Tesla to Pittsburg

4.10 Simulation Process

Once model parameters (discussed above) are determined, a 24-hour unit commitment and hourly economic dispatch can be simulated for the typical day in each season under various scenarios discussed above, subject to a set of transmission constraints: hard transmission constraints on grandfathered paths, soft constraints on all transmission lines/transformers/local area constraints that are not grandfathered. Ideally, the same process will be repeated until all seasons, all scenarios, and all potentially pivotal supplier combinations are exhausted. For this initial study we present results for all load and hydro production scenarios and most supplier combinations for the spring and summer seasons only. The second set of CPA results released during the Summer of 2007 will include a larger set of withdrawn supplier combinations for all load and hydro scenarios for all four seasons.

5 Demonstration of Competitive Path Assessment

As stated above, typical days in spring and summer season are picked for the preliminary competitive path analysis. For each typical day, various potentially pivotal supplier combinations are evaluated for each of the nine load, hydro scenarios. In the following section, we will first focus on the base case – Medium Load and Medium Hydro in the spring without any suppliers' capacity removed. Next, we present results for the high load, low hydro scenario for all 43 supplier combinations for removed capacity for spring, and finally the results for all load and hydro scenarios and supplier combinations for spring. The same is repeated for the summer season.

5.1 Base Case Results

The base case results for spring are presented in Table 9 below for medium load, medium hydro, and no supplier capacity withdrawn. General simulation characteristics are presented including load, average LMPs, total generation internal to the CAISO, net import values, and internal path flows (path 15 and Path 26) for each of the 24 hours of the spring medium load medium hydro base case.

Table 9. Base Case: Model Output for Spring, Medium Hydro, Medium Load, and No Supply Withdrawn

	Load (MWh)		Price ($/MWh)		Generation (MWh)		Net Import		Internal Path Flow (MWh)	
Hour	NP26	SP26	NP26	SP26	NP26	SP26	NW	SW	P15 (S->N)	P26 (S->N)
1	10,906	13,734	$40.07	$38.24	10,165	8,326	2,483	3,778	712	-1,373
2	10,668	12,965	$42.01	$37.89	10,319	7,730	1,625	3,643	745	-1,365
3	10,643	12,382	$42.64	$34.90	10,300	7,429	1,355	3,672	1,017	-1,094
4	10,415	12,049	$32.34	$30.96	10,083	7,250	1,255	3,598	1,043	-1,011
5	10,383	11,909	$27.75	$23.53	9,882	7,228	1,437	3,538	1,062	-966
6	10,280	11,542	$13.23	$7.37	9,338	7,028	1,579	3,900	1,465	-498
7	10,645	11,973	$18.29	$12.00	9,327	8,014	3,021	3,594	1,850	-219
8	10,806	13,183	$23.87	$14.41	9,879	8,554	3,055	3,872	1,801	-349
9	11,432	14,697	$43.41	$37.82	10,763	9,183	3,359	3,749	1,247	-966
10	12,147	16,247	$44.03	$39.81	11,432	10,307	3,736	4,047	1,263	-1,040
11	12,691	17,725	$47.25	$43.60	12,783	10,571	3,883	4,098	484	-2,202
12	13,095	18,860	$48.76	$45.65	13,343	11,216	3,905	4,005	326	-2,796
13	13,463	19,678	$50.59	$47.71	14,513	11,402	3,960	3,809	195	-3,461
14	13,694	20,446	$53.33	$49.76	15,076	11,398	3,961	4,226	-206	-3,862
15	13,948	20,888	$54.69	$51.43	15,276	11,744	3,962	4,439	-216	-3,844
16	14,105	21,122	$53.45	$51.52	15,341	11,830	3,930	4,379	-388	-4,000
17	14,190	21,181	$52.39	$48.74	15,627	11,524	3,891	4,781	-397	-4,000
18	14,156	20,752	$54.91	$50.82	15,214	11,752	3,935	4,381	-148	-3,753
19	13,811	19,884	$50.78	$46.43	14,526	11,396	3,918	4,249	92	-3,390
20	13,348	19,188	$49.26	$44.05	14,098	10,816	3,567	4,216	-195	-3,289
21	13,759	19,280	$52.65	$47.89	14,681	11,089	3,349	4,032	336	-3,303
22	12,960	17,775	$46.69	$41.99	13,484	10,147	3,320	4,053	-64	-2,724
23	11,681	15,656	$44.75	$40.58	11,469	9,074	2,931	4,234	644	-1,695
24	10,963	14,024	$40.52	$37.10	10,837	8,627	2,574	3,725	960	-1,186

The load-weighted zonal LMPs for both NP26 and SP26 is below $55/MWh, which reflects a relatively abundant low-cost supply system wide. The NP26 area is a net importer during the morning hours when inexpensive imports are available from other control areas. As the load grows, NP26 internal generation can meet all of its load and even provide relatively small amount of export. The SP26 area is a net importer throughout the day with the largest import of over 8,700 MW in hour 17. The power flows on the internal paths are from north to south (from ZP26 into SP15) for Path 26 and from south to north (ZP26 to NP15) for Path 15, which are nominal flow directions in spring. Path 26 is binding from north to south for hours 17 and 18 with a hard limit of 4,00MW. The total imports into the CAISO control area nearly 4,000 MW from the Northwest during most of the peak hours and are over 4,700 MW from the Southwest. The base case results are characteristic of actual operating conditions in a typical spring in the CAISO.

Table 10. Base Case: Branch Group Flows for Spring, Medium Hydro, Medium Load, and No Supply Withdrawn

Branch Group	Min Limit	Max Limit	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
ADLANTOSP_BG	-502	1036	702	718	728	728	712	697	542	553	528	514	513	515	501	503	521	519	514	506	477	505	530	528	677	565
BLYTHE _BG	-140	200	10	10	10	10	10	10	23	161	199	185	157	157	192	173	154	156	125	171	193	200	200	200	190	13
CASCADE _BG	-45	80	0	0	0	0	0	0	0	0	0	0	80	80	80	80	80	80	80	80	80	80	0	0	0	0
CFE _BG	-408	800	75	75	75	75	75	75	84	99	113	122	87	87	212	168	88	137	136	88	81	75	87	87	162	75
CTNWDRDMT_BG	-370	370	-257	-257	-257	-257	-257	-257	-257	-257	-258	-258	-258	-259	-259	-259	-259	-259	-259	-259	-258	-258	-258	-258	-258	-259
CTNWDWAPA_BG	-1594	1594	-43	-57	-51	-52	-57	-59	-26	-49	-143	-113	-129	-157	-176	-176	-186	-167	-192	-174	-145	-152	-131	-96	-109	-202
ELDORADO _BG	-1555	1555	1009	880	880	880	880	855	890	890	940	890	860	863	860	1053	1170	1093	1337	1141	1011	990	890	890	910	880
GONDIPPDC_BG	-51	15	-13	-13	-13	-13	-13	-13	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-13	-13
IID-SCE _BG	-100	600	492	492	492	495	495	499	496	520	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493
IID-SDGE _BG	-225	225	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
INYO _BG	-56	56	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IPPDCADLN_BG	-471	647	627	617	617	617	617	617	452	384	396	396	396	396	381	381	398	396	396	396	399	395	442	444	583	471
LAUGHLIN _BG	-222	220	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LLNLTESLA_BG	-164	164	10	10	10	10	9	7	10	8	7	5	1	5	7	6	5	-5	-3	-1	0	-4	-2	-2	3	3
MCCLMKTPC_BG	-686	686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MCCULLGH _BG	-2598	2598	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEAD _BG	-1460	1460	656	655	674	670	645	888	598	864	747	1060	1201	1075	732	722	801	820	978	774	769	761	749	748	1015	913
MEADMKTPC_BG	-369	369	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEADTMEAD_BG	-182	182	0	0	0	0	0	5	1	8	3	12	11	13	14	16	17	17	12	4	0	12	13	9	19	19
MERCHANT _BG	-645	645	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MKTPCADLN_BG	-423	423	75	101	111	111	95	80	90	169	132	118	117	119	120	122	123	123	118	110	78	110	88	84	94	94
MONAIPPDC_BG	-544	478	172	162	162	162	162	162	-24	-92	-80	-80	-80	-80	-95	-95	-78	-80	-80	-80	-77	-81	-34	-32	174	168
N.GILABK4_BG	-366	366	53	0	0	0	0	0	0	0	0	40	57	57	57	57	57	57	57	57	57	57	57	57	53	53
NOB _BG	-1465	2091	543	0	0	0	43	153	1331	1386	1560	1895	1923	1900	1957	1936	1947	1927	1927	1900	1900	1557	1436	1416	1037	934
PACI _BG	-2450	3199	2040	1725	1455	1355	1494	1526	1790	1769	1798	1839	1878	1873	1871	1875	1883	1871	1832	1903	1936	1928	1911	1902	1885	1669
PALOVRDE _BG	-3328	3328	1486	1491	1501	1431	1396	1540	1654	1734	1666	1701	1641	1671	1836	2070	2070	2070	2070	2070	2070	2070	1951	1971	1726	1461
PARKER _BG	-60	220	12	12	12	12	12	12	41	41	91	171	171	171	171	186	186	186	186	186	186	171	171	171	20	12
PATH15 _BG	-9999	5400	712	745	1017	1043	1062	1465	1850	1801	1247	1263	484	326	195	-206	-216	-388	-397	-148	92	-195	336	-64	644	960
PATH26 _BG	-4000	9999	-1373	-1365	-1094	-1011	-966	-498	-219	-349	-966	-1040	-2202	-2796	-3461	-3862	-3844	-4000	-4000	-3753	-3390	-3289	-3303	-2724	-1695	-1186
RNCHLAKE _BG	-1271	1271	372	336	338	335	330	327	240	86	133	182	338	425	324	325	288	400	329	298	306	306	301	306	285	185
SILVERPK _BG	-17	17	17	17	17	17	17	17	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	17	17
SUMMIT _BG	-100	70	-100	-100	-100	-100	-100	-100	-100	-100	2	2	2	52	52	70	52	52	52	52	2	2	2	2	9	-29
SUTTRNP15_BG	-1366	1366	250	102	0	0	0	0	0	0	180	250	250	525	525	525	525	458	288	525	525	525	525	525	250	31
SYLMAR-AC_BG	-1200	1200	62	59	59	59	62	62	62	62	110	62	110	110	112	112	112	112	112	112	112	112	111	111	63	63
TRACYCOTP_BG	-118	152	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRACYPGAE_BG	-4388	4352	568	542	526	533	527	454	371	349	425	432	514	569	560	568	571	631	585	622	627	690	589	595	552	473
VICTVL _BG	-560	1518	236	236	186	186	186	136	136	136	136	136	136	123	123	123	123	123	123	123	123	123	123	123	136	186
WSTWGMEAD_BG	-126	126	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Limits and hourly flows for existing Branch Groups for the Spring, medium load, medium hydro base case are shown in Table 10.

5.2 Spring Season Results

The FI summary results for Spring Low Hydro High Load and all 43 supplier combinations for withdrawn capacity are presented in Table 11. Candidate paths listed in the first column represent an aggregate for that constraint set. More specifically, for certain constraints there is more than one physical facility (line, transformer) or simultaneous flow constraint that is associated. In these cases, the minimum FI value for all physical facilities and simultaneous flow constraints associated with the aggregate constraint is used as the FI value for that aggregate constraint for that hour. Where final path designations are made, the designation will apply to all physical facilities and simultaneous flow constraints associated with the aggregate constraint for which the designation is made. The second column in the table shows the total hours simulated. The simulation is run for 24 hours, and in the case of spring low hydro high load, there are 1,032 hours simulated (24 hours * 43 supplier combinations). The second column is the minimum calculated FI value for that candidate path across all hours simulated. Instances where there is a "*" symbol in this column relate to hours where load was curtailed to solve the power flow and a proxy negative FI value was inserted for all candidate paths that did not have a negative calculated FI. This approach is discussed in greater detail below. Fourth column shows the number of hours where the FI, calculated or proxy, was less than zero. The fifth column shows the percent of simulated hours where the FI, calculated or proxy, was less than zero.

The minimum FI value reported in the third column is interpreted as follows: the magnitude of the value indicates the proportion of the path limit that was exceeded by the simulated flow in order to solve the simulation with some combination of suppliers' capacity removed.

Table 11. FI Results for Spring - Low Hydro, High Load Scenarios and 43 Supplier Combinations for Withdrawn Capacity

Candidate Path	Total Hours Simulated	Minimum FI	Hours w/ FI < 0	Percent of Hours w/ FI < 0
Bogue Area Import	1,032	-0.15	20	1.9%
Colgate 60 kV	1,032	-1.38	426	41.3%
Humboldt Bank	1,032	*	3	0.3%
Humboldt Import	1,032	*	3	0.3%
Imperial Valley Bank	1,032		0	0.0%
Llagas to Gilroy	1,032	*	3	0.3%
Metcalf to El Patio	1,032	*	3	0.3%
Metcalf to Morgan Hill	1,032	*	3	0.3%
Miguel Import	1,032		0	0.0%
Miguel Max Import	1,032		0	0.0%
MiraLoma Bank	1,032		0	0.0%
Monta Vista - Jefferson	1,032	*	3	0.3%
Moss Landing to Metcalf	1,032	-0.23	38	3.7%
North Geysers Import	1,032	*	3	0.3%
North of Martin	1,032	*	3	0.3%
Oakland 115kV	1,032	-0.02	25	2.4%
Palermo - Colgate	1,032	*	3	0.3%
Palermo 115kV	1,032	-0.36	74	7.2%
Pittsburg Transformers	1,032	*	3	0.3%
Pittsburg to San Mateo_E. Shore	1,032	*	3	0.3%
Ravenswood Cutplane	1,032	*	3	0.3%
Ravenswood to San Mateo	1,032	-0.35	168	16.3%
Sobrante - Grizzly - Claremont	1,032	*	3	0.3%
South of Lugo	1,032		0	0.0%
Table Mt - Rio Oso	1,032	*	3	0.3%
Table Mt - Rio Oso & Palermo	1,032	*	3	0.3%
Tesla - Manteca	1,032	*	3	0.3%
Tesla Banks 6 & 4	1,032	*	3	0.3%
Tesla to Delta Switchyard	1,032	-0.22	46	4.5%
Tesla to Pittsburg	1,032	-0.46	71	6.9%

* Denotes instances where there was no measured negative FI, but a proxy negative FI was inserted for at least one hour due to dropped load in the zone where the candidate path resides.

The top two most violated candidate paths in term of frequency are “Colgate 60 kV” with negative FI values in more than 40% of simulated hours, and “Ravenswood to San Mateo” with negative FI values in over 16% of simulated hours. The “Palermo 115kV” and “Tesla to Pittsburg” constraints also showed frequencies of negative FI in over 5% of hours simulated. For this set of simulation runs, only five candidate paths showed no instances of calculated negative FI values (identified by a “0” in the “Hours w/ FI < 0” column of Table 11): Imperial Valley Bank, Miguel Import, Miguel Max Import, Mira Loma Bank, and South of Lugo.

In instances where the simulation model could not meet all load with a particular supplier combination removed, the zone in which the load was curtailed is considered to be uncompetitive in that hour and all candidate paths in that zone are (manually) forced to have a negative FI. In some instances, the calculated FI (using simulated flow) will be negative. However, in cases where the FI for a candidate path residing in a zone where load was curtailed is not negative, a proxy negative FI value is substituted for purposes of determining whether or not the candidate path is competitive. For spring simulations, these instances were concentrated in the NP26 area when withdrawn supplier combinations included at least two of the three largest suppliers in that area.

The FI summary results for all load and hydro scenarios and supplier withdrawn combinations in spring are presented in Table 12. The last column shows the seasonal competitive test results with a test threshold of zero hours with negative FI. A column value of "Fail" indicates that based on the FI values resulting from the simulation (and substitution in cases where load was curtailed) the candidate path failed the competitiveness test for that season. A blank value indicates the path passed the seasonal competitiveness test.

Table 12. FI Results for Spring - All Load and Hydro Scenarios and 43 Supplier Combinations for Withdrawn Capacity

Candidate Path	Total Hours Simulated	Minimum FI	Hours w/ FI < 0	Percent of Hours w/ FI < 0	Test w/ 0% FI < 0
Bogue Area Import	9,288	-0.15	20	0.2%	Fail
Colgate 60 kV	9,288	-1.38	669	7.2%	Fail
Humboldt Bank	9,288	*	3	0.0%	Fail
Humboldt Import	9,288	*	3	0.0%	Fail
Imperial Valley Bank	9,288		0	0.0%	
Llagas to Gilroy	9,288	*	3	0.0%	Fail
Metcalf to El Patio	9,288	*	3	0.0%	Fail
Metcalf to Morgan Hill	9,288	*	3	0.0%	Fail
Miguel Import	9,288		0	0.0%	
Miguel Max Import	9,288		0	0.0%	
MiraLoma Bank	9,288		0	0.0%	
Monta Vista - Jefferson	9,288	*	3	0.0%	Fail
Moss Landing to Metcalf	9,288	-0.23	100	1.1%	Fail
North Geysers Import	9,288	*	3	0.0%	Fail
North of Martin	9,288	*	3	0.0%	Fail
Oakland 115kV	9,288	-0.04	69	0.7%	Fail
Palermo - Colgate	9,288	*	3	0.0%	Fail
Palermo 115kV	9,288	-0.36	112	1.2%	Fail
Pittsburg Transformers	9,288	*	3	0.0%	Fail
Pittsburg to San Mateo_E. Shore	9,288	*	3	0.0%	Fail
Ravenswood Cutplane	9,288	*	3	0.0%	Fail
Ravenswood to San Mateo	9,288	-0.36	504	5.4%	Fail
Sobrante - Grizzly - Claremont	9,288	*	3	0.0%	Fail
South of Lugo	9,288		0	0.0%	
Table Mt - Rio Oso	9,288	*	3	0.0%	Fail
Table Mt - Rio Oso & Palermo	9,288	*	3	0.0%	Fail
Tesla - Manteca	9,288	*	3	0.0%	Fail
Tesla Banks 6 & 4	9,288	*	3	0.0%	Fail
Tesla to Delta Switchyard	9,288	-0.24	138	1.5%	Fail
Tesla to Pittsburg	9,288	-0.48	274	3.0%	Fail

* See note for same symbol corresponding to Table 11.

The results for all load and hydro scenarios and all 43 supplier combinations are similar to the high load, low hydro results presented in Table 11 except that the relative frequency of negative FI values for certain candidate paths is somewhat lower. This is expected, since Table 11 shows results for the most conservative set of system conditions where we expect supply to be relatively tight compared to the other load and hydro scenarios in the spring.

Another item worth noting in the full set of spring simulation results is that there are a significant number of candidate paths with only three hours of negative FI values and showing less than one tenth of one percent relative frequency of negative FI values for the spring. These specific (negative FI) hours are a result of dropped load that occurred on one of the 384 simulated days (43 supplier combinations * 3 load scenarios * 3 hydro scenarios = 384 simulated days).

5.3 Summer Season Results

The FI summary results for Summer Low Hydro High Load and all 43 withdrawn supplier combinations are presented in Table 13.

Table 13. FI Results for Summer - Low Hydro and High Load Scenarios

Candidate Path	Total Hours Simulated	Minimum FI	Hours w/ FI < 0	Percent of Hours w/ FI < 0
Bogue Area Import	1,032	-0.14	40	3.9%
Colgate 60 kV	1,032	-1.31	528	51.2%
Humboldt Bank	1,032	*	20	1.9%
Humboldt Import	1,032	-0.01	56	5.4%
Imperial Valley Bank	1,032	*	7	0.7%
Llagas to Gilroy	1,032	-0.08	31	3.0%
Metcalf to El Patio	1,032	*	20	1.9%
Metcalf to Morgan Hill	1,032	-0.04	20	1.9%
Miguel Import	1,032	-0.18	79	7.7%
Miguel Max Import	1,032	-0.12	39	3.8%
MiraLoma Bank	1,032	*	13	1.3%
Monta Vista - Jefferson	1,032	-0.01	22	2.1%
Moss Landing to Metcalf	1,032	-0.32	81	7.8%
North Geysers Import	1,032	-0.03	46	4.5%
North of Martin	1,032	*	20	1.9%
Oakland 115kV	1,032	-0.10	111	10.8%
Palermo - Colgate	1,032	*	20	1.9%
Palermo 115kV	1,032	-0.36	90	8.7%
Pittsburg Transformers	1,032	0.00	21	2.0%
Pittsburg to San Mateo_E. Shore	1,032	*	20	1.9%
Ravenswood Cutplane	1,032	*	20	1.9%
Ravenswood to San Mateo	1,032	-0.45	210	20.3%
Sobrante - Grizzly - Claremont	1,032	*	20	1.9%
South of Lugo	1,032	-0.07	16	1.6%
Table Mt - Rio Oso	1,032	*	20	1.9%
Table Mt - Rio Oso & Palermo	1,032	*	20	1.9%
Tesla - Manteca	1,032	*	20	1.9%
Tesla Banks 6 & 4	1,032	*	20	1.9%
Tesla to Delta Switchyard	1,032	-0.25	53	5.1%
Tesla to Pittsburg	1,032	-0.53	94	9.1%

* See note for same symbol corresponding to Table 11.

Note here that during the summer we observe a much higher frequency of negative FI values across all candidate paths compared to spring with the same load and hydro scenario and withdrawn supplier combinations. This is to be expected due to the higher load, and resulting tighter supply conditions, in the summer compared to spring.

The issue of curtailed load appears in both the north and south areas in the CAISO control area in a total of nine withheld supplier cases. This resulted in thirteen candidate paths receiving a proxy negative FI value in at least 20 hours each where those thirteen candidate paths would not otherwise have had a calculated negative FI value for the summer high load low hydro scenario. These instances are denoted by a "*" in the third column of Table 13.

The top three most violated candidate paths, both in terms of frequency and most negative FI values, for the summer high load low hydro scenario are "Colgate 60 kV", "Humboldt Import", and "Tesla to Pittsburg", with "Ravenswood to San Mateo" and "Palemo 115kV" trailing slightly.

The FI summary results for all load and hydro scenarios and supplier withdrawn combinations in summer are presented in Table 14.

Table 14. FI Results for Summer - All Hydro and Load Scenarios

Candidate Path	Total Hours Simulated	Minimum FI	Hours w/ FI < 0	Percent of Hours w/ FI < 0	Test w/ 0% FI < 0
Bogue Area Import	9,288	-0.14	80	0.9%	Fail
Colgate 60 kV	9,288	-1.31	1,597	17.2%	Fail
Humboldt Bank	9,288	*	34	0.4%	Fail
Humboldt Import	9,288	-0.01	115	1.2%	Fail
Imperial Valley Bank	9,288	*	7	0.1%	Fail
Llagas to Gilroy	9,288	-0.08	55	0.6%	Fail
Metcalf to El Patio	9,288	*	34	0.4%	Fail
Metcalf to Morgan Hill	9,288	-0.04	35	0.4%	Fail
Miguel Import	9,288	-0.18	128	1.4%	Fail
Miguel Max Import	9,288	-0.12	52	0.6%	Fail
MiraLoma Bank	9,288	*	20	0.2%	Fail
Monta Vista - Jefferson	9,288	-0.01	39	0.4%	Fail
Moss Landing to Metcalf	9,288	-0.32	217	2.3%	Fail
North Geysers Import	9,288	-0.03	110	1.2%	Fail
North of Martin	9,288	*	34	0.4%	Fail
Oakland 115kV	9,288	-0.10	319	3.4%	Fail
Palermo - Colgate	9,288	*	34	0.4%	Fail
Palermo 115kV	9,288	-0.36	288	3.1%	Fail
Pittsburg Transformers	9,288	-0.01	45	0.5%	Fail
Pittsburg to San Mateo_E. Shore	9,288	*	34	0.4%	Fail
Ravenswood Cutplane	9,288	*	34	0.4%	Fail
Ravenswood to San Mateo	9,288	-0.45	939	10.1%	Fail
Sobrante - Grizzly - Claremont	9,288	*	34	0.4%	Fail
South of Lugo	9,288	-0.09	39	0.4%	Fail
Table Mt - Rio Oso	9,288	-0.01	34	0.4%	Fail
Table Mt - Rio Oso & Palermo	9,288	-0.01	34	0.4%	Fail
Tesla - Manteca	9,288	*	34	0.4%	Fail
Tesla Banks 6 & 4	9,288	*	34	0.4%	Fail
Tesla to Delta Switchyard	9,288	-0.26	196	2.1%	Fail
Tesla to Pittsburg	9,288	-0.54	558	6.0%	Fail

* See note for same symbol corresponding to Table 11.

The results for the Summer season in Table 14 show that no candidate paths pass the competitiveness test. Similar to the Spring summary, "Colgate 60kV" and "Ravenswood to San Mateo" have the highest frequency of negative FIs across all simulation runs within the season. Note that if a candidate path fails the competitive test in one season, that path will be designated as uncompetitive for the entire year.

The issue of curtailed load appears in again here in both the north and south portions of the CAISO control area in a total of 34 cases when capacity from more than one supplier is withdrawn.

6 Concluding Comments and Next Steps

The results from the typical spring and summer day with various load, hydro, and withheld supplier capacity scenarios show that under strict testing conditions, all candidate paths are deemed *Non-Competitive*. These test results, however, appear to be sensitive to the test threshold and when allowing up to five percent of hours with a negative FI show that nearly all candidate paths do not fail the competitiveness test and would be deemed competitive.

It is important to note that some of the necessary limitations and assumptions used in this study warrant treating these preliminary results with a degree of caution. Some of the more significant limitations and assumptions that may result in some degree of error in the competitive path assessments include the following:

- The candidate paths selection reflect the examination of local congested areas based on the 12-month period historical RMR and OOS dispatches between June 1, 2005 and May 31, 2006. The list of candidate competitive paths needs periodic update to reflect any new bottlenecks that might appear in the CAISO transmission system.

- There will likely be some new generation or transmission changes that will come on line between now and the start of MRTU. The full network model used in the CPA requires periodic update to reflect the most recent topology of the network and generation mix and to be consistent with the MRTU IFM.

- The current simulation does not consider N-1/G-1 contingency cases which will be considered in MRTU IFM. Considering contingency cases will likely reduce line flow capability and will likely result in higher probability of observing a negative FI.

The next steps include the following

- Test the new SC-OPF function in the simulation software used in this study and implement this feature in future releases,
- Incorporate the most recent FNM used in the MRTU IFM software.
- Update the candidate path list using real-time RMR dispatch data and out-of-sequence dispatch data from a more recent time period.
- Perform simulation for other seasons under various load, hydro, withdrawn supplier scenarios;

7 List of Appendices

Appendix A: Identifying Candidate Competitive Paths