Z·GLOBAL
ENGINEERING & ENERGY SOLUTIONS

FOR DISCUSSION AND REVIEW

June 29/2010

Comments and Questions on Draft CTPG Phase 3 Study Report

We appreciate the work that CTPG is doing and we value the opportunity you have given to the various stakeholders to submit alternatives to be studied under the CTPG process. On behalf of our Clients, we have reviewed your draft and are providing the following comments, questions and observation on the (1) Green Energy Express (GEET), a double circuit, 500 KV AC line (2) Metro Renewable Express Project "MRE", two underground DC line with 2,000 MW rating from Devers to Mira Loma (3)The Pony Express Project "PE" from El Dorado to Devers 500 KV, AC line and (4) Clean Path Energy project connecting Los Banos – Westley through a new single or double 230 KV AC line.

Four main comments that we like to bring to your attention, as we will address them in more detail in the body of this report.

Q1. In all the phase 2 and phase 3 studies, CTPG has assumed a certain level of renewable generation, overlaid LGIP utility proposed transmission upgrades and then identified the reliability violations that resulted from connecting these renewable into the transmission grid. CTPG then tested the submitted ITP proposed transmission and other alternatives to access which ITP and other alternatives performed better in resolving these reliability violations. This process is flawed in many ways. This process is inconsistent with FERC policies under FERC 890 Transmission Planning Principles and incompatible of prudent transmission planning. We ask how the CTPG analysis resulted in the most efficient transmission plans to meet the 33% RPS if all the proposed transmission projects are not evaluated equally so the project(s) that connect the most renewable generation with the least reliability impact is recommended. The CTPG assumptions will not achieve CTPG goal of "… efficiently meet the state 33% RPS" and we ask that CTPG to re-study the proposed ITP on an equal basis. Furthermore, we strongly recommend that all proposed projects should be evaluated equally to better access the effectiveness of each proposed project in connecting renewable to the load center and resolving overloads. Only approved projects should be modeled in the base case.

Q2. The assumption of the Renewable zones for peak MW and GWH should be consistent with signed PPA's and should reflect the LSE commercial interests. In at least two scenarios, CREZ zones with signed PPA's were not considered.

Q3. The analysis for each proposed transmission project, regardless of the project sponsor, should evaluate the incremental benefits of each alternative. For instance, if a renewable zone has a potential of 5,000 MW and 750 MW was selected to be the level of renewable to include in the base case, a simple re-conductoring may be enough to resolve reliability problems. However, what if an additional 500 MW from the same renewable zone were to be interconnected? The preferred re-conductoring alternative would quickly become insufficient to mitigate system overloads.

Q4. There is a wide range of changes in the base case assumptions on tie flows from one scenario to the next. For instance, the Phase 3 Northern California peak scenario has South to North flows from California to the Northwest of about 800 MW (see page 39 table 7.2.2). In reality, we expected over 5,000 MW of Imports from the Northern Region on COI and PDCI. In the Southern California Peak scenario, the flows from the NW into California were more realistic, the NW flow from COI were at 4,322 MW and 3,100 MW from the PDCI (Table 7.3.2). Why would California export to the Northwest under Northern California peak and export from Southern California to the NW during autumn, large amounts of energy over 4700MW (Table 7.7.2) Peak?

A. Grid Configuration:

Table 2.1 on page 13, list the projects "... With key regulatory approvals and environmental permits"

Q5. Although we were able to find many records of CAISO and PUC approval on the Sunrise and Tehachapi Transmission Projects, the approval of the Colorado River – Devers - Valley is conditional based on adequate generation interconnection. CAISO approved the PVD2-Devers, however, we are unable to confirm that CAISO has in fact approved Colorado River – Devers- Valley line as previously mentioned. We believe that only approved projects by CAISO (for the IOU's) should be modeled in the base case.

Q6. Furthermore, Table 2.1 lists the upgrades "... Without regulatory approval…" we believe that the Colorado River-Devers Valley Line upgrade should not be modeled in the base case. Modeling these projects in the base case defeats the CTPG stated objectives, "The purpose of the 2010 CTPG study for 2020 is to develop a state-wide transmission plan that identifies the transmission infrastructure needed to reliability

and efficiently meet the state's 33% RPS goal." By including this in the base case it is not being accurately weighed against alternative projects.

Modeling specific projects in the base case that have not received regulatory approval may undermine the CTPG goals and place other transmission proposals at a disadvantage and at the same time give preferential treatment to the IOUs.

B. Base case assumptions and Scenarios

It appears that the renewable assumptions under the Northern and Southern peak load scenarios were based on RETI best CREZ zones and the rest of the scenarios were based on renewable levels in current generation interconnection queues. Below is a couple of comments and recommendations:

Q7. Utilizing the CREZ Best zone is unrealistic since the IOU's have executed several PPA's and CAISO/Utilities have executed several IA's in renewables zones that are not listed in Northern and Southern Summer peak case under renewable assumptions in Tables 7.2.4 and 7.3.4. For example, the Kramer area has 344 MW of LSE commercial interests (Table 4.3) but the value used in the two scenarios was 3256 MW. Riverside East LSE commercial interest (Table 4.3) of 1562 MW but 0 MW was used in the two scenarios. We recommend that a signed PPA and IA be considered first and then use a Renewable portfolio that is consistent with generation interconnection to be applied to all scenarios.

Q8. The table below contains all the generation interconnection in San Bernardino area. We are unable to determine how the 3256 MW was determined?

Queue Position	Application Status	Fuel	Summer	County	Station or Transmission Line	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Interconnecti Agreement Status
23	**Complete**	**NG**	**72**	**San Bernardino**	**San Bernadino 220+M127 kV**	**Complete**	**Complete**	**IFA Executed**
68	Active - Serial	S	850	San Bernadino	Pisgah 230 kV Substation	Re-Study Complete	Complete	LGIA Execute
89	Active - Serial	NG	570	San Bernardino	Victorville Substation	Complete	Complete	In Progress
125	Active - Serial	S	250	San Bernardino	Coolwater-Kramer 230kv line	Complete	Complete	
131	Active - Serial	S	100	San Bernardino	Loop new sub connecting to Eldorado-Mtn Pa	Complete	Complete	LGIA Execute
135	Active - Serial	W	60	San Bernardino	Lugo-Pisgah 230kV line	Complete	In Progress	
136	Active - Serial	NG	300	San Bernardino	Etiwanda 230kV Substation	Complete	Complete	In Progress
139	Active - Serial	NG	698	San Bernardino	SCE Rancho Vista 500kV Sub	Complete	Complete	In Progress
142	Active - Serial	S	80	San Bernardino	Kramer Substation	Complete	In Progress	
156	Active - Serial	W	201	San Bernardino	Lugo-Pisgah 230kV line	Complete	In Progress	
162	Active - Serial	S	114	San Bernardino	Loop new sub connecting Eldorado-Mtn Pass	Complete	Complete	In Progress
163	**Active - Trans Cluster**	**S**	**300**	**San Bernardino**	**Mountain Pass Substation 115kV**	**Complete**	**In Progress**	
233	Active - Serial	S	200	San Bernardino	Ivanpah Substation 230kV	Complete	Complete	In Progress
240	Active - Serial	S	400	San Bernardino	Pisgah Sub 230kV	Complete	In Progress	
241	Active - Serial	S	400	San Bernardino	Pisgah Sub 230kV	Complete	In Progress	
474	Active - SGIP	S	19.9	San Bernardino	Dunn Siding Substation	In Progress		
491	Active - Cluster #1	S	230	San Bernardino	Coolwater-Dunn Siding 115kV line	In Progress		
497	Active - Cluster #1	S	6	San Bernardino	New Ivanpah Substation 115kV	In Progress		
498	Active - Cluster #1	S	20	San Bernardino	New Ivanpah Substation 115kV	In Progress		
499	Active - Cluster #1	S	40	San Bernardino	New Ivanpah Substation 115kV	In Progress		
524	Active - SGIP	S	20	San Bernardino	Eldorado-Pisgah #2 230kV line			
552	Active - Cluster #2	S	60	San Bernardino	Lugo-Pisgah #1 230kV line			
589	Active - Cluster #2	S	60	San Bernardino	Victor Substation 115kV			
593	Active - Cluster #2	S	310	San Bernardino	Mohave Generating Station 500kV bus			
			5360.9					

Q9. How is CTPG dealing with FERC recent March 2010 order prohibiting Load dropping for N-1?

B.1 RETI Best CREZ – Northern California Peak (RETI-BC_Asn)

Q10. COI and PDCI flows seem to be unrealistic. For instance, the COI S-N flow into the Northwest during Northern California Peak conditions is 135 MW S-N under A1 case (no renewable dispatch) and 778 MW S-N with renewable dispatch under the A2 case. Given the signed PPA from the Northwest, what are the bases for such a low COI / PDCI flows?

Q11. Under Table 7.2.2 "Major Intertie Flows", the Path 15 flow in the A2 case exceeds the rating (flow = 7,325 MW on a 5400 MW rating), please explain ?

Q12. The CREZ assumptions in Table 7.2.4, does not support enough generation to be connected to Sunrise, (344 MW) why?

B.2 RETI Best CREZ – Southern California Peak (RETI-BC_Bns)

Q13. Given that the Colorado River - Devers line has a conditional approval subject to adequate generation interconnection, why would the line be modeled in this scenario where Riverside East renewable generation was assumed to be 0 MW?

B. 3 In State Scenario section 7.4

Q14. Please provide major tie flow under the A1 case, although the load in section 7.4 is the same for the Northern California Case, the renewable dispatch is 12,152 MW.

In state scenario, Southern California peak (B-Q)

Q15. Why is the tie flow under the B-Q scenario (Table 7.5.2) different from the Southern California scenario – Best CREZ table 7.3.2? We understand that the B-Q scenario is aimed at testing the in-state scenario with CO2 re-dispatch for out of state, however, the results showed a West to East flow of the EOR. Is it possible to have a W-E on the EOR and E-W flow on the WOR systems? If we anticipate this scenario, do we assume that some of the 500kV line that California is building will be used to export energy? Is it realistic to assume the coal plants in the region can be cycled with solar and wind to the extent modeled? Please explain.

Q16. The swing in EOR/WOR flows between the autumn and summer peak cases such are quite large. Is it practical to see such a large swing when it can lead to cycleing of coal plants in the southwest? What was a CTPG assumption for coal generation into California?

In state scenario, Northern California peak (A2 Northern)

Please provide the EOR/WOR flows under table 7.6.2.

B. 4 autumn case

Q17. Please provide the major tie flow for the F1 case under Table 7.7.2.

Q18. Table 7.7.2 shows higher than rating flows on Path 15. Please explain.

Q19. What was the import level at Palo Verde? With a Riverside East at 2528MW and import from PV (assuring full deliverability), what are the N-O, N-1, N-2 outages results for East and West of Devers? MWD comments to RETI indicates their reluctance to re-conductor their 230 kV line.

C. Transmission needs Alternative Analysis

Given that the Colorado River - Devers has a conditional approval subject to adequate generation interconnection, why model this line? It was modeled in the base case and in all scenarios including the case where the ITP proposal was studied and it was modeled in the

Northern and Southern California scenarios (section 7.2 and 7.4) where Riverside East renewable were assumed to be at 0 MW.

C.1 Green Energy Express Project:

Q20. The CTPG alternative lists a re-conductor project of the MWD Julian Hinds-Mirage 230V line. Is this a feasible alternative and has MWD been contacted with regards to re-conductoring their line?

Q21. CTPG is proposing a SPS to trip one Blythe Combustion turbine for an N-1 of the Julian Hinds-Mirage. The California ISO Planning Standards (ISO G5, Page 6) outlines SPS guidelines and states that an SPS designed against single contingency outages cannot cascade outages beyond the outage of the facility that the SPS is intended to protect – even in the event that the SPS fails to operate. This is not the case for a SPS that is designed against a double contingency – as the probability of an N-2 is much less. The standards go further to say that if the SPS failed to operate then the resultant overload on the protected element cannot trip on overload protection. The magnitude of the post contingency overload is substantial enough to assume that the line would trip on overload protection. Have you concluded that the CTPG assumption is within CAISO SPS guidelines to list this as a feasible solution?

Q22. The Green Energy Express alternative includes a new fast acting phase shifter that will respond in the event of a disturbance to resolve overloads on the 230kV system near Eagle Mountain. The percentage loading table in Section 8.9.1.5 indicates that an outage of the Eagle Mountain-Iron Mountain 230kV line will overload the Julian Hinds-Mirage, Eagle Mountain-Julian Hinds, and Julian Hinds Sectionalizing Breaker, during an outage of the Eagle Mountain-Iron Mountain 230kV line. The Green Energy Express phase shifter will adjust and will resolve overloads on the 230kV system; With the addition of a phase-shifting transformer, the flow on the 230kV can be redirected to the 500 kV system, thus reduced the line loading on the Eagle Mountain – Julian Hinds – Mirage 230 kV line. The double circuit structure will also provide a solid 500 kV backbone. With a 2000 MW capacity and a parallel path to the existing Palo Verde-Devers 500 kV line, and enhance the reliability of the existing 230 kV line from Eagle Mountain to Devers. However, it appears that the phase shifter was static or locked for the CTPG analysis. The post contingency flows were the same with and without the GEET project. However, if the phase shifter was acting properly this would not be the case. Can you please confirm if the PST was locked and what would the result be if the PST was unlocked? Below are information obtained from the PST manufacture summarizes the expected operations of the PST:
The most economic design for large phase shifting transformers is one unit for sizes up to 1500MVA, 500kV with +/-20 degrees under no-load. If there are physical transport constraints, then two PST 'S units can be deployed in parallel to achieve the power transfer requirements. The use of an advance-retard switch is permitted, +/-32 steps can be reached and the throughput capacity [e.g. approx 750MVA at +/-20 degrees

under no-load] is achievable. The transient response for the Siemens design phase shifters, standard angle step size is determined by the available step capacity of the on-load tap changer. For example, 1500MVA, +/-20 degrees under no-load, A minimum step size is achieved with a +/- 32 step tap changer (e.g. 0.625 degree per step)

While the amount of MW shifted per degree will not be linear over the whole PST range, let's assume linearity for illustration purposes. In that case, each tap changer step will result in a shift of approx. 47 MW per tap changer step.
The time per step is approx. 5.5 sec for the load- tap changer that Siemens uses, which is furnished by Reinhausen (Siemens holds a 26% equity in Reinhausen.) For the design discussed above, this means that eleven steps (approx 1 minute) will shift > 500 MW, or approximately 11 seconds per each 100 MW shift.

The time over entire tap range can then be easily calculated depending on the number of steps in one direction. For +/- 16 steps it means 88sec (approx. 1.5 minutes) from zero to full lead or full lag tap position. For +/-32 steps the time is then 176 sec (approx. 3 minutes)

Q23. EOR/WOR Flow assumption seems very low: The EOR and WOR flows during on peak are typically within 500MW of each other. In addition EOR flows typically approach their rating during on peak conditions. On page 100, CTPG lists the EOR flows at 4621MW (Rating = 9300MW). This assumption is very low and almost half the size of the WOR flows. What was the rationale behind these flows?

Q24. The Riverside East renewable generation is listed at 2528MW; however, CTPG indicates that only one new line is required between Colorado River and Devers substations. The approximate rating on this line is 1200MW. CTPG must have assumed a reduction in Palo Verde imports in order to accommodate the additional 2528MW of generation plus imports from Palo Verde. We want to ensure that the reduction in Palo Verde flows takes into account contracts that CAISO participants hold for firm imports at Palo Verde and also renewable generation that is slated to be imported from out of state. Please confirm this information.

Q25. What is the rationale of using Phase 2 studies and not the Southern California scenario outlined in the Phase 3 studies? What are the differences?

Q26. The maximum installed capacity studied by CTPG for the Riverside East CREZ/Renewable Development Area is 2528 MW. This is significantly lower than the generation identified in the CAISO generation interconnection queue shown in Table 1 below:

As of May 28th, 2010 the CAISO queue has a total of 5,944.5 MW of installed capacity and more than double the generation that was considered in the CTPG studies.

Furthermore, Table 1 to 3 below shows the following for East Riverside County:

1. Total Generation in the CAISO queue requesting interconnection in Riverside County is 8,151.5 MW (Table 2).
2. Out of the 8,151.5 MW, a total of 5,944.5 requested interconnection in the East of Riverside (Table 2) where the GEET project is located. In addition, there is 1996 MW requesting interconnection at Devers or West of Devers where the MRE project is proposed.
3. For the East Riverside, the 5,994.5 MW represents 3,205MW of installed capacity identified at Colorado River and Midpoint Substations alone, with an additional 2,739.5 MW at Red Bluff, and Eagle Mountain area.
4. Table 2 shows 3737 MW of have either signed an IA or in the process of executing an IA. In addition, there are 2199.5 MW that have completed System Impact Study (SIS) and have decided to move to the next and final step of Facility Study (FS). This bring a total of over 5900 MW of generation that are in an advanced stage of the process and over 2200 MW of generation that are in initial stage of the process.

California Controlled Gris Generation Queue as of May 28, 2010

		Generating Facility		Maximum MWs	Location	Point of Interconnection	Study Availability		
Queue Position	Application Status	Type	Fuel	Summer	County	Station or Transmission Line	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Interconnection Agreement Status
1	Active - A39	WT	W	16.5	Riverside	Devers-Garnet 115 kV line (Tap)	Complete	Complete	IFA
3	Active	CT	NG	850	Riverside	Devers Substation 230 kV Bus	Complete	Re-study Complete	Executed
11A	Active	CC	NG	520	Riverside	Julian Hinds Substation 230kV	Complete	Complete	Executed
17	Active - Serial	CC	NG	520	Riverside	Devers-Palo Verde 500 kV line near Blyth	Complete	Complete	In Progress
49	Active - Serial	WT	W	100.5	Riverside	Devers Substation	Re-Study Complete	Re-study Complete	
50	Active	CC	NG	810	Riverside	SCE Valley Substation	Complete	Complete	IA Executed
72	Active - Serial	H	WTR	500	Riverside	Proposed Lee Lake Substation	Complete	Complete	In Progress
138	Active - Serial	WT	W	150	Riverside	Devers-Vista 230kV #1	Complete	Complete	In Progress
146	Active - Serial	PV	S	150	Riverside	Eagle Mountain Substation	Complete	Complete	In Progress
147	Active - Serial	PV	S	400	Riverside	Red Bluff Substation 230kV switchyard	Complete	Complete	In Progress
193	**Active - Trans Cluster**	**ST**	**S**	**500**	**Riverside**	**Colorado River Substation**	**Complete**	**In Progress**	
219	Active - Serial	CT	NG	50	Riverside	Midpoint Substation 500kV	Waived	Waived	Tendered
294	**Active - Trans Cluster**	**ST**	**S**	**1000**	**Riverside**	**Midpoint Substation 500kV**	**Complete**	**In Progress**	
365	**Active - Trans Cluster**	**ST**	**S**	**500**	**Riverside**	**Midpoint Substation**	**Complete**	**In Progress**	
421	**Active - Trans Cluster**	**ST**	**S**	**49.5**	**Riverside**	**Eagle Mountain Substation**	**Complete**	**In Progress**	
431	**Active - Trans Cluster**	**ST**	**S**	**150**	**Riverside**	**Midpoint Substation 220kV**	**Complete**	**In Progress**	
567	Active - Cluster #2	H	WTR	1400	Riverside	Red Bluff Substation 230kV	In Progress		
572	Active - Cluster #2	PV	S	110	Riverside	Valley Substation 500kV bus	In Progress		
576	Active - Cluster #2	PV	S	485	Riverside	Colorado River Substation 230kV bus	In Progress		
588	Active - Cluster #2	PV	S	200	Riverside	Red Bluff Substation 230kV	In Progress		
616	Active - SGIP	PV	S	20	Riverside	Eagle Mountain-Blythe 161kV line	In Progress		

Table 2 – CAISO Queue for Riverside County including the status of the various generation projects

Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	MW	Full Capacity or Energy Only (FC/EO)	County	Utility	Station or Transmission Line	Current On-line Date
7/26/2002	7/26/2002	Active	CC	NG	520		Riverside	SCE	Julian Hinds Substation 230kV	8/1/2010
3/18/2003	3/18/2003	Active - Serial	CC	NG	520		Riverside	SCE	Devers-Palo Verde 500 kV line near Blythe	8/1/2010
11/16/2006	11/16/2006	Active - Serial	PV	S	150		Riverside	SCE	Eagle Mountain Substation	12/31/2009
11/16/2006	11/16/2006	Active - Serial	PV	S	400		Riverside	SCE	Red Bluff Substation 230kV switchyard	2/1/2010
3/19/2007	4/4/2007	Active - Trans Cluster	ST	S	500	FC	Riverside	SCE	Colorado River Substation	7/1/2013
5/7/2007	5/23/2007	Active - Serial	CT	NG	50		Riverside	SCE	Midpoint Substation 500kV	6/1/2012
1/15/2008	1/16/2008	Active - Trans Cluster	ST	S	1000	FC	Riverside	SCE	Midpoint Substation 500kV	7/1/2013
5/6/2008	5/12/2008	Active - Trans Cluster	ST	S	500	FC	Riverside	SCE	Midpoint Substation	7/1/2013
5/30/2008	5/30/2008	Active - Trans Cluster	ST	S	49.5	FC	Riverside	SCE	Eagle Mountain Substation	2/1/2012
5/30/2008	5/30/2008	Active - Trans Cluster	ST	S	150	FC	Riverside	SCE	Midpoint Substation 220kV	7/1/2014
1/28/2010	2/1/2010	Active - Cluster #2	H	WTR	1400	FC	Riverside	SCE	Red Bluff Substation 230kV	6/1/2016
1/29/2010	2/1/2010	Active - Cluster #2	PV	S	485	FC	Riverside	SCE	Colorado River Substation 230kV bus	12/31/2013
1/29/2010	2/1/2010	Active - Cluster #2	PV	S	200	FC	Riverside	SCE	Red Bluff Substation 230kV	12/1/2012
3/15/2010	3/17/2010	Active - SGIP	PV	S	20	EO	Riverside	SCE	Eagle Mountain-Blythe 161kV line	7/1/2012
				Total	5944.5					
Notes:										
Midpoint Substation is the same as Colorado River Substation - Name change not yet reflected for all earlier Queued projects										
Total MW Connecting to Eagle Mountain (includes 161 KV line from Blythe to Eagle Mountain and Julian Hinds Sub) =									739.5	
Total MW Connecting to Red Bluff Substation =									2000	
Total MW connecting Colorado River/Midpoint Substation =									3205	
								Total	5944.5	

Table 2 – CAISO generation interconnection queue in Riverside County

item	Riverside County (CAISO Queue)	East of Devers (not including devers) MW	Derves and West of Devers, MW	Total (MW)
1	Excecuted IA	570	1346.5	1916.5
2	Complete FS. IA in progress	1170.5	650	1820.5
3	Sub Total (1 + 2)	1740.5	1996.5	3737
4	Completed SIS. FS in progress	2199.5	0	2199.5
5	Sub Total (1 + 2 +4))	3940	1996.5	5936.5
6	SIS in progress	2215	0	2215
7	Total (3+5+7)	6155	1996.5	8151.5

Table 3 – Various stages of CAISO Generation Interconnection in Riverside County

5. Furthermore, the Renewable Energy Transmission Initiative (RETI) Phase 2B Final Report (May 2010) lists that the Riverside East Capacity Estimate is 10,550MW.

Table 1-1. Phase 2B CREZ Capacity Estimates.

CREZ	Capacity, MW				
	Biomass	Geothermal	Solar Thermal	Wind	Total
Barstow			1,400	936	2,336
Carrizo North			1,600		1,600
Carrizo South			3,000		3,000
Cuyama			400		400
Fairmont	138		1,800	712	2,650
Imperial East			1,500	74	1,574
Imperial North-A		1,370			1,370
Imperial North-B	30		1,800		1,830
Imperial South	36	64	3,570	45	3,715
Inyokern			2,145	287	2,432
Iron Mountain			4,800	62	4,862
Kramer		24	6,185	203	6,412
Lassen North				1,467	1,467
Lassen South				410	410
Mountain Pass			780	178	958
Owens Valley			5,000		5,000
Palm Springs				333	333
Pisgah			2,200		2,200
Riverside East			10,550		10,550
Round Mountain-A		384			384
Round Mountain-B				132	132
San Bernardino - Baker			3,350		3,350
San Bernardino - Lucerne	91		1,540	599	2,230
San Diego North Central				200	200
San Diego South				678	678
Santa Barbara				433	433
Solano				894	894
Tehachapi	37		7,195	3,193	10,425
Twentynine Palms			1,805		1,805
Victorville			1,200	436	1,636
Westlands			5,000		5,000
Grand Total	**332**	**1,842**	**66,820**	**11,273**	**80,267**

Based on these facts, CTPG 2528 MW of renewable in east Riverside County is a very conservative assumptions and we would request CTPG run a sensitivity for the GEET and MRE Projects with the following assumption and under full deliverability:

a. 2200 MW connecting at Colorado River / Midpoint
b. 2000 MW connecting at Eagle Mtn/ Red Bluff
c. 850 MW connected at Devers Substation

Q27. The objective of the Green Energy Express is not to resolve N-1 or N-2 overloads. The evaluation of GEET under Section 8.9 of the report is focused on whether GEET or the alternative (re-conductoring the existing line) will reduce the existing N-1 and N-2 thermal overload. We would not propose a 500kV line to resolve an overload on the 230kV system. The CTPG study uses the same generation and load levels under both cases (with and without GEET). Connecting no Generation to GEET is not the objective of GEET; however, CTPG study shows that the GEET project has no adverse reliability impacts. Please confirm what configuration of GEET was used to derive the results in Table 8.9.1.5. Also please confirm why a planning study is only adding facilities to solve the reliability concerns and ignores the effects on the system of the generation scheduled to be delivered as shown in the queue

Q28. The Table in Section 8.9.1.5 shows several thermal overloads under N-1. For instance, upon the loss of Julian Hinds – Mirage 230kV line, the Eagle Mountain – Julian Hinds lines will overload to 143.4% without mitigation, and therefore, it appears that the base case has N-1 and N-2 violations. Please confirm this information?

Q29. We understand that the existing SPS is designed to drop MWD pumps or generation to resolve overloads. It appears that the SPS, if it exists, is able to prevent the overload under N-1 for current conditions. GEET is not designed to solve an existing reliability problem and the focus should be, whether GEET can officially connect more renewable generation without exasperating the current overloads that CTPG outlined in Table 8.9.1.5 on page 113 under the title, "Without Mitigation." Can you confirm the base case with no renewable interconnection does not show any overload facilities under N-1, and N-2, with and without the SPS?

Q30. GEET submitted several configurations; among them is a 500kV line from Red Bluff to Devers. Was this configuration considered?

Q31. On page 115, under Section 8.9.1.6, CTPG concluded that 2528MW can be connected to the Colorado River and Red Bluff substations as long as; (1) the CR-Red Bluff – Devers – Valley 500kV is in place, (2) the 230kV line is re-conducted, and (3) installing SPS. Furthermore, CTPG Table 8.9.1.5 shows the loading on the 230KV system with "CTPG Phase 2 Mitigation." If this is the case, why build a Red Bluff station and why not connect the renewable on the Eagle Mt or the Julian 230kV line?

Q32. It appears that CTPG analysis does not assure full deliverability of the 2528MW of renewables connecting to Red Bluff and Colorado River? Please confirm this information.

On page 116, CTPG stated an N-2 on Devers – Red Bluff #1 and #2 500kV lines. Is the Devers – Red Bluff #1 part of PVDI? Is the Devers – Red Bluff #2 part of the CR – Red Bluff – Devers – Valley?

Q33. Can you provide the N-O, N-1, N-2 flows under the conditions with no renewable generation outlined in the Table on page 8.9.1.5?

Q34. Table 2.1 outlines the Transmission upgrades added or removed from the Seed Case in order to produce the CTPG cases. In the first column titled "Upgrades with Key Regulatory Approvals and Environmental Permits" CTPG lists the following upgrades around Devers:

a. New Colorado River ("Midpoint") 500kV Substation looping in existing Palo Verde-Devers #1line
b. 500kV Colorado River-Devers #2 line
c. 500kV Devers-Valley #2 line

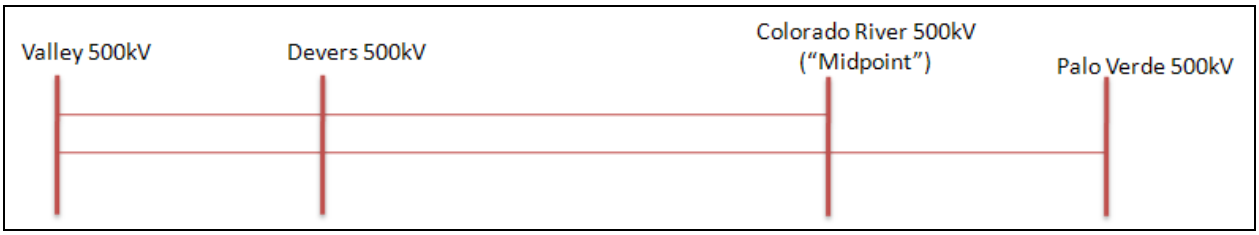

Figure 1 – basecase configuration showing the new Colorado River Valley 500kV

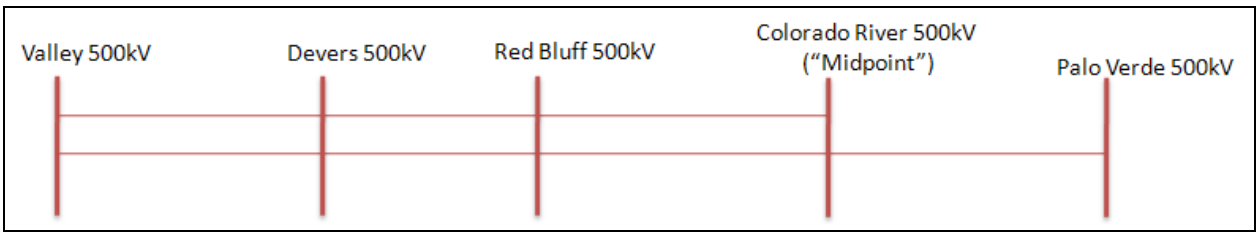

Figure 2 – Basecase configuration showing a new Red Bluff 500 kV station

Please confirm that the configuration in Figure 2 represents the CTPG base case. Also our analysis shows that the GEET with one line from Eagle – Red Bluff – Devers and the second circuit is from Eagle to Devers results in higher reliability than the Red- Bluff Devers 500kv line that was modeled in the base case. This GEET configuration provides incremental benefits of interconnecting higher number of renewable with minimum incremental cost. Please analyze a scenario that represents the GEET configuration in the base case instead of the Red Bluff –Devers to examine which alternative provide a superior reliability?

Q35. Under the phase 3 study, what would be the purpose of modeling Red Bluff and Colorado River in the Northern and Southern California Peak scenario while the Riverside East renewable is ZERO?

Q36. Under the Phase 2 study, Table 7.10.3, the Riverside East renewable is set at 3767 MW. The rating of the new Colorado River – Devers is 1200MW. How could the 3767 MW be interconnected to the new line and ensure deliverability?

Q36. In the scenarios where the Riverside East installed capacity was 2528MW, how much was placed at the Red Bluff, Colorado River, and Eagle Mountain? What was the distribution? How was the distribution computed?

C.2 Metro Renewable Express (MRE):

Q.37 The primary objective of the Metro Renewable Express is not just to resolve N-1 or N-2 problems but to provide additional transmission capacity to transport low cost energy to the load center. The MRE has the rating of 2000 MW to be injected into the Mira Loma station load pocket. The evaluation of MRE under Section 8.7 of the report is focused on whether MRE or the alternative (re-conductoring the existing lines) will reduce the N-1 and N-2 thermal overload in the "West of Devers" area. We would not propose an underground 2,000 MW DC line to simply resolve an overload on the 230kV system,

Q38 Also our analysis shows that the MRE project with two cables, each rated at 1000 MW shows higher reliability than the Devers – Valley 500kv line that was modeled in the base case. This MRE configuration provides incremental benefits of interconnecting higher number of renewable with minimum incremental cost. Could you analyze a scenario that represents the MRE configuration in the base case instead of the Devers –Valley 500kV to examine which alternative provide a superior reliability?

Q39. The Table in Section 8.9.1.5 shows several thermal overloads under N-1 without the MRE or the re-conductoring project. Under each of the five contingencies listed, many facilities show thermal overloads. For instance, upon the loss of the 230kV line, the Eagle Mountain – Julian Hinds line will overload to 143.4% without mitigation, it appears that the base case has N-1 and N-2 violations. Please confirm?

Q40. Under the current operating conditions (the current system), it appears that the loss of the Devers –Valley 500kV line will result in an overload of the 230 kV West of Devers during off-peak conditions with high intertie flow. Our analysis shows that the stressed case for the Devers area is during off-peak and autumn. Under these conditions, we observed an overload of the West of Devers (WOD) 230 kV system when one or both Devers – Valley 500 kV line are out.

In fact, the West of Devers 230kV Rebuild was outlined to CAISO in 2008 by SCE results which showed the following reliability issues[1]: 110-116% overload under base case condition, up to 164% overload under various N-1, up to 173% overload under various N-2 and requested CAISO approval to re-conductor the 230 kV West of Devers. It appears that WOD overload is an existing Reliability issue without the addition of Renewables? Please explain this information?

[1] **SCE Proposed Mitigations for 2008 Annual Transmission Reliability Assessment and Compliance Plan for 2009-2018,** http://www.caiso.com/2083/2083d648668d0.pdf, page 8

Q41. We understand that SCE has installed an SPS to protect against the 230 kV overload. Would the SPS be modified under any of the scenarios studied? Can you confirm that under the autumn case and off-peak case during high WOR/EOR flow conditions, that an N-1 and N-2 will overload the WOD facilities?

Q42. Under the CTPG's Draft Phase 2 study report presentation to the RETI Transmission Working Group dated June 17, 2010, the CTPG report concludes that the results of the Proposed Devers – Mira Loma line "Mitigates the West of the Devers Overloads". With the injection of 500 to 1000 MVAR into Mira Loma from the Voltage Source Converter (VSC), we see additional voltage and transient stability benefits. Are you planning to perform a voltage and transient stability study? Also, please provide the assumptions for the once through Cooling (OTC) dispatch.

Q43. Section 8.7 of the CTPG report outlines studies that were conducted for the West of Devers Area. The Metro Renewables Express alternative was described in this section and points out that MRE resolves all overloads. Have you evaluated the impact of MRE on increasing the South of Lugo path ratio and impact on OTC? In the Power flow results on P104, what are the Renewable assumptions?

Q44. Unknown DC schedule assumption: The percentage loading Table in Section 8.7.1.5 is highly dependent on the pre and post contingency flows on the DC alternative project. It is crucial to assume maximum flow on the DC in the base case. DC Schedules that are too low would be an inefficient use of the DC and will result in higher post contingency flows on the limiting elements. What was the MRE DC schedule in the basecase?

Q45. Can you please provide the N-0 flow conditions on the MRE and on the system connecting to Devers?

Q46. Was the West of Devers SPS modeled through the analysis?

Q47. Can you provide transmission line loadings under N-0 for the GEET and MRE alternatives for lines west and east of Devers? No consideration for off peak conditions where curtailment is historically the highest: It is important to include an off-peak base case. During off peak conditions the load at San Bernardino, Vista, and Etiwanda are low. The lower the load the less the off-take on the 230kV system will be and the higher the flows on the lines out of San Bernardino. An off-peak case may show that re-conductoring alone will not resolve thermal overloads.

Q48. EOR/WOR Flow assumption is low: The EOR and WOR flows during on peak are typically within 500 MW of each other. In addition EOR flows typically approach their rating during off- peak conditions. On page 100, CTPG lists the EOR flows at 4621MW (Rating = 9300MW). This assumption is very low and almost half the size of the WOR flows. What was the rationale behind the flows on EOR and WOR?

Q49. Section 8.9 of the CTPG report outlines studies that were conducted for the East Palm Springs area. The Green Energy Express alternative was described in this section. The concerns listed above (Section 2) about the Riverside East renewable assumptions would have a large effect on the results of this section. In addition, there are five additional concerns with this evaluation.

C.3 Los Banos (LB) – Westley project

Q50. On page 94, CTPG found that an N-2 on the LB-Tesla 500kV lines will overload the Los Banos bank to 110% of the its rating, the existing LB – Westley line by 120% of its rating with the proposed 2nd 230KV LB-Westley lie. We interpret these results to indicate that there overloads that are observed with the proposed 2nd 230KV line in place and the existing LB – Westley line in place (no re-conductoring). Please confirm this information.

Q51. The proposed LB – Westley 230kV #2 line consist of separate structure with a new LB 500/230kV transformer (1122 MVA) with a rating of 400MW and a capability to have a single bundled line, if needed, with a rating of 800MW or two lines with 400 mw each. Please confirm the rating you used on the proposed LB – Westley and whether a higher rating will mitigate the overload?

Q52. Under the scenario where the existing line is re-conductored, CTPG findings show that the reconductored line mitigates the overload under the N-2. Please verify that information since under both scenarios (the reconductoring scenario and the new line) the power will have to flow through the single 500/230kV bank at LB. We are surprised that under the re-conductoring alternative, no bank overload is found even though, and as you also observed, that under the re-conductor alternative, the flow across the bank may result in a higher flow due to lower impedance, versus the alternative scenario (new line). Please provide N-0, N-1, N-2 loadings for the two scenarios (re-conductor): with 400 mw and 800MW rating on the new line and with/ without the new proposed bank with 1122 rating?

C.4 Eldorado – Devers 500 kV (AC)

Q53. It is very difficult to provide any feedback on the Pony Express since we do not have the N-0, N-1, N-2 loadings with and without the project. Can you provide the N-0, N-1 and N-2

Q54. Several transmission lines are planned to bring cheap energy into the El Dorado valley. Projects such as TransWest, TransCanada and the SWIP project. From a regional planning prospective, it will be prudent to evaluate this project versus some of the LGIP projects in the CTPG base case? In addition, the proposed Pony express utilizes existing designated transmission corridor directly south of El dorado and avoid the El Dorado – Market place = Mead – Lugo corridor. We request to run a sensitivity with 1200 MW imports from Eldorado to Devers.

Miscellaneous:

Throughout the document, ZGlobal was listed as the stakeholder; however ZGlobal is a consultant to the stakeholder. Please update all references in the draft report to reflect:

a. Los Banos-Westley No. 2 Line – Stakeholder: Clear Path Energy LLC
b. The Eldorado – Devers 500kV, AC line – Stakeholder: Pony Express LLC
c. Metro Renewable Express – Stakeholder : Metro Renewable Express LLC
d. Green Energy Express Transmission Line – Stakeholder : 21st Century Transmission

Thank you again for your efforts. Please email Armie Perez (Armie@zglobal.biz), or Jenny Mueller (Jenney@zglobal.biz) or call us at (916) 985 - 9461