2004 Reliability Must-Run Technical Study of the ISO-Controlled Grid

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Final Version

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I Introduction

Over the past several months, the California ISO (ISO) has been working on the "2004 Reliability Must-Run Technical Study of the ISO-Controlled Grid (RMR Study)" through an open stakeholder process. This RMR Study builds upon the large foundation of work established in the previous four RMR technical studies listed below.

- Five-year Reliability Must-Run Technical Study of the ISO-Controlled Grid
- 2000 Reliability Must-Run Technical Study of the ISO-Controlled Grid
- 2001-2003 Reliability Must-Run Technical Study of the ISO-Controlled Grid
- 2002-2004 Reliability Must-Run Technical Study of the ISO-Controlled Grid
- 2003 Reliability Must-Run Technical Study of the ISO-Controlled Grid

This RMR Study Report details the ISO's technical studies that were performed to identify RMR requirements and RMR generator unit candidates for year 2004. The development of the RMR requirements is attained through a coordinated stakeholder effort. As such, the ISO would like to take this opportunity to gratefully acknowledge Stakeholder support and encouragement given to the ISO Staff during the course of this RMR Study.

II. Executive Summary

As in previous years the RMR studies have been performed in order to determine the minimum MW of market generation required to be on-line in a certain local area in order to be able to reliably serve the load. An ISO Stakeholder meeting was held on May 7, 2003 to present RMR study results and solicit stakeholder comments.

This RMR Study evaluated the transmission grid under anticipated heavy summer operating conditions in 2004 with a singular focus on determining RMR requirements in the RMR areas identified in previous RMR studies as well as any new RMR areas that were identified during the previous year. It is expected that the 2004 RMR results will be the basis for one-year (2004) RMR contracts.

Eleven RMR areas were identified in previous RMR studies, based on transmission upgrades selected in the 1999 LARS, the Chico area was eliminated as a RMR area and it will be eliminated from this year's write-up. All areas, including Chico, are analyzed each year for completeness.

The ISO study findings, based on the study plan and RMR Criteria, are:

1. Confirming the results presented in the 2001-2003 RMR study, the Chico area will not be considered an RMR area in the 2004 time frame, due to the installation of new transmission facilities in 1999.
2. As a result of this study to determine RMR requirements in 2004, aggregate RMR requirements on the ISO controlled grid are expected to be 9,805[1] MW.

   Compared to 2003 results of 12,058 MW (as identified in last year's Study (refer to Table VIII-1, page 11)), the reduction in 2004 RMR requirements are mostly due to new transmission projects rather then load growth and new generation units.
3. 241 units were identified as being effective in serving RMR requirements in the 2004 time frame. This compares with 268 effective units for year 2003. The differences in individual effective units between 2004 and the previous 2003 RMR Study are due to new transmission projects, load forecast, changes in status of QF units, new merchant power plants and new peaking units. Specific units considered effective in serving the RMR requirements in the 2004 time frame are listed in Attachment 1. *In accordance with the LARS process, it should be noted that these units will go through a screening process to identify and eliminate units that are not eligible to participate in the LARS RFP process (refer to section III).*

III. Description of the RMR/LARS Process

Over the years, generation and transmission expansion projects were built to serve increasing consumer load growth. These projects were integrated with the facilities that preceded them. In many cases, certain generation-related components, in whole or in part, complement transmission-related components. Generation-related components benefit the transmission grid in several ways, including: providing voltage support, reducing heavy power flows on certain transmission lines, and minimizing the oscillatory nature of the electric system. In these situations, generation and transmission facilities are interdependent in maintaining grid reliability.

California's restructured electric market potentially allows for the temporary absence or permanent elimination of certain generators from the transmission grid. However, as noted above, there are certain situations where generation and transmission facilities are interdependent, where the absence of some generating units could compromise reliability in different ways, including reduced voltage support on the system and increased thermal loading of transmission facilities. A generating unit, whose absence could have a detrimental impact on reliability in a discrete local area under specified operating conditions, is categorized as a "Reliability Must Run" (RMR) generating unit.

The completion of the RMR Process is achieved through the "Local Area Reliability Service (LARS)" process. The LARS initiative is the process by which the ISO determines how to mitigate local area reliability problems. To initiate the LARS process, the ISO staff conducts a technical study to determine which specific areas within the ISO controlled grid exhibit local reliability problems and the technical requirements necessary to mitigate identified local reliability problems. The ISO then issues a Request for Proposal (RFP) that can satisfy the requirements. Market Participants are encouraged to submit alternatives to RMR generation to satisfy the LARS MW requirement for each identified LARS area. The ISO considers generation, transmission and

[1] Plus the Pmax for the biggest unit signed in the Western LA Basin

demand-side related proposals. ISO staff then evaluates the alternatives and compares them on a cost-effectiveness basis, subject to certain constraints such as operating characteristics, among others. The ISO also considers transmission projects submitted by the Participating Transmission Owners (PTOs) through their annual transmission assessments. Based on these considerations, ISO management presents the list of preferred alternatives to the ISO Board for approval.

A Screening Process is followed to eliminate identified units from the Unit Candidate list based on a set of principles involving contractual relations and exemptions due to generator unit size (e.g. currently units less than 10 MW). The resulting new "Unit Eligibility" list represents unit candidates that are eligible to receive an RMR contract. This Screening Process is part of the LARS Process.

Units on the Unit Eligibility list are then compared to other generation, transmission and demand-side proposals in the LARS RFP process. The LARS RFP process is the final step in selecting and presenting the preferred RMR mitigation alternatives to the ISO Board for approval. In response to the LARS RFPs made public by the ISO, the PTOs and interested stakeholders are encouraged to submit competitive proposals to mitigate RMR Criteria violations.

IV. Study Objectives

For the ISO Controlled Grid as planned for year 2004 determine:

1. RMR requirements, as applicable, for each of the RMR areas and subareas.

2. RMR generator candidate units to satisfy the RMR requirements in each of the applicable RMR areas and subareas.

V. Study Methodology

The Assessment Process included investigation into potential RMR-related reliability impacts in local areas that are internal to the ISO Controlled Grid. This assessment focused on those areas and sub-areas identified in RMR studies for 1999 and verified and revised (as necessary) in the 2000, 2001-03, 2002-04 and 2003 RMR studies. As required, additional studies were conducted to address new reliability concerns within RMR local areas and sub-areas. The following outline gives a general description of the Assessment Process.

1. To examine potentially low voltage and excessive thermal loading conditions, load modeled in the respective base cases represented a maximum anticipated coincident peak load for the ISO Control Area, based upon a one-in-five-year ("80/20") heat wave. The base cases were adjusted in accordance with the Key Assumptions pertaining to base case development and modeling, identified herein. Final adjustments were made to the base cases as required to ensure accurate system representation and modeling, acceptable bus voltages and no criteria violations.

2. In the 1998 RMR Study, minimum load concerns (high voltage conditions and/or possible thermal loading) were not found to be a determining factor in designating RMR units. Based on historical assessments of the Grid, the ISO continues to believe that minimum load concerns are not a factor in the determination of designating RMR units. Therefore, a minimum load condition (light winter base case) was not developed for this year assessment.

3. A local area approach was used to assess the impact of RMR on transmission facility loading and voltage limits. The following 10 RMR areas and 15 RMR subareas of the ISO Controlled Grid were evaluated independently:

   I. Humboldt Area
   II. Battle Creek Area
   III. North Bay Area
      1. Eagle Rock Subarea
      2. Fulton Subarea
   IV. Vaca-Dixon Area
   V. Greater Bay Area
   VI. Sierra Area
      1. Colgate Subarea
      2. Placer Subarea
      3. Drum-Rio Oso Subarea
   VII. Stockton Area
      1. Tesla Subarea
      2. Valley Springs Subarea
      3. Lockeford Subarea
   VIII. Fresno Area
      1. Panoche Subarea
      2. McCall Subarea
      3. Henrietta Subarea
      4. Reedley Subarea
      5. Herndon Subarea
   IX. LA Basin Area
      1. Western Subarea
      2. Eastern Subarea
   X. SDG&E Area

   Each sub-area is defined by their electrical connection to adjoining systems and the internal generation. These sub-areas were also being investigated for RMR requirements.

4. Stakeholders have provided system changes that are expected to occur for the respective 2004 operating year. The ISO assessed these changes and determined the extent that additional technical analysis was required. For example, if an RMR area required 100% of its generating units to be designated RMR in 2003 and system changes expected between 2003 and 2004 would not reduce the RMR requirement, then the area will continue to require 100% of its in-area generators in 2004. If, in the same example, the changes would tend to significantly reduce RMR requirements, then it would be necessary to perform a technical study to determine the new reduced RMR requirement for that area. System changes should include the expected status of QF's for the year of the study.

5. Each limiting contingency may involve power flow, post-transient, or transient stability analysis. RMR units were individually and successively subtracted from the base case until applicable thermal and/or voltage criteria violations occur.

6. Based on the analysis of item 5 above, the identity of generating units in each of the RMR areas that would be candidates to participate in the 2004 LARS RMR process was determined. It is

recognized that it may not be necessary to designate all generating units located within the same plant site as Must Run. The results of items 5 & 6 were being shared with the Participating Stakeholders prior to the Final Report.

VI. Key Study Assumptions

The ISO adopted the following assumptions in performing power flow, dynamic stability and post-transient simulations.

1. The focus was on identifying the generating units that would have to be on line to meet the applicable reliability criteria for the year 2004 conditions (i.e. Must-Run designation), given a baseline set of assumptions listed in this Study Plan.

2. The power flow base cases used in this study incorporate the latest Annual Planning Assessment Base Cases for SCE, SDG&E, and PG&E. These areas models were combined into the WSCC base case 2007HS1.

3. Regulatory "Must Take" resources (i.e. generating units from Nuclear, QF, and Public Power Utilities sources) were dispatched at their contract ratings; otherwise nameplate ratings or typical operating performance was used.

4. The remaining available capacities of the interconnected transmission lines were used to import economy power from outside the ISO Controlled Grid.

5. Imports into the ISO Controlled Grid were adherent to any operating constraints that was in effect. This means that flows on the California Oregon Intertie (COI) path were represented no higher than the maximum level in the season being studied in accordance with the seasonal operating capabilities determined by the WSCC Operating Transfer Capability Policy Group (OTCPG). The flows on the Arizona to California path was represented no higher than the maximum level allowable based on the Southern California Import Transmission (SCIT) nomogram.

6. Hydro generation located within the ISO Controlled Grid was dispatched according to historical average data provided by the PTO's.

7. All QF generation explicitly represented in the power flow base cases hade their reactive power capabilities modeled according to contractual requirements, otherwise historical operating data was used. Actual reactive power capabilities (from manufacturers' or field test data) were represented for performing dynamic stability analyses as available.

8. All QF generation connected to busses rated 230 kV and above were explicitly represented in the power flow and stability base cases.

9. All QF generation connected to busses rated below 230 kV to 60 kV inclusive, were explicitly represented in the power flow base cases and may be load netted for stability analyses. If multiple QF generating units are connected to the same bus, they may be aggregated at that bus and use an equivalent representation in the power flow base cases and for stability analyses.

10. Most QF generation connected to busses rated below 60 kV were netted with the nearest load that is fed from the respective generating unit.

11. The ISO power flow base cases were adjusted to reflect an ISO Control Area simultaneous summer peak load condition for the respective years, based on a forecasted 1-in-5-year heat wave.

12. Loads on systems within California that are not participating in this study were adjusted in proportion to the nearest system under ISO control.

13. Reactive load was represented in the base cases to reflect reasonable values for the operating conditions being studied.

14. In the Initial Base Cases, at least 5-7% operating reserve within the ISO Controlled Grid was met based on the WSCC methodology used in developing base cases.

15. Studies included pre-disturbance operating conditions (i.e. a facility initially out of service and system readjusted).

16. The 2004 RMR Study was conducted using the GE pslf program (versions 13.1 and/or 13.2).

17. All existing generating resources within California that are expected to be available for service by June 1st of the respective base case years, was represented.

VII. Contingencies Simulated

Critical contingencies refer to disturbances (e.g. line outages) that result in the more severe RMR Criteria violations compared to other contingencies analyzed. The critical contingencies simulated included the outage or outages that resulted in defining the RMR requirement in each respective RMR area or subarea. Depending on the RMR area, these outages involved the loss of a single facility or the one overlapping contingency (generator initially out of service followed by a transmission line outage (G-1/N-1)) resulting in, for the most part, violations to the thermal ratings of transmission equipment or unacceptably low voltages and/or reactive margins. Refer to the study details provided in the Appendices, for the specific critical contingencies simulated, if required, in the RMR area of interest.

The concept of a critical contingency in no way implies that it is the only contingency that results in a RMR Criteria violation in a particular area or subarea. There may be other contingencies of the same or different classes that result in violations, albeit less severe. This year the ISO staff has informed the stakeholders about other contingencies that may require RMR units in most of the existing RMR areas and sub-area. ISO Management expects that assessments performed by PTOs or interested stakeholders to identify competitive alternatives to RMR generator unit designations will include all contingencies in the RMR area and applicable contiguous areas to adequately determine the benefits of the proposed alternatives.

VIII. Study Findings – Area Definition and Requirements

The figures shown on subsequent pages of this section identify the areas and sub-areas in which RMR criteria violations occur and from which RMR requirements are defined. Consequently, the RMR Study focussed on these areas and sub-areas that directly impact RMR MW requirements on the ISO controlled grid. Figure 1 on page 12 shows the 10 existing RMR areas pictorially.

A physical description of the key areas and subareas follows.

Pacific Gas & Electric System

The Humboldt area covers most of Humboldt County. The grid is comprised of 60 kV and 115 kV transmission lines. Internal generation in the Humboldt area consists of two 53 MW thermal generating units, two 15 MW mobile gas turbines (GTs), one 25 MW biomass self-generator and 36 MW of QF generation. Additionally, there is one off-line generator in the area having a capacity of 10 MW.

The Battle Creek area covers the north central portion of Tehama County and the south central portion of Shasta County. The grid is comprised of 60 kV transmission lines. Internal generation in the Battle Creek Area consists of 9 hydro generators (total maximum generation = 42.9 MW), 16 units of reciprocating engine generators (total maximum generation = 49.9 MW) and 3 Qualifying Facility (QF) hydro generators (total maximum generation = 9.5 MW).

The North Coast/North Bay area covers Mendocino, Lake, Sonoma, Napa counties as well as a small portion of Solano County. The grid is comprised of 60 kV, 115 kV and 230 kV transmission lines. Internal generation consists of 1,258 MW of geothermal generating units, three hydro units totaling 9 MW and 140 MW of QF generation.

The Vaca-Dixon area covers the south portion of Yolo County and most of Solano County. The grid is comprised of 230 kV, 115 kV and 60 kV transmission elements. Internal generation consists of 2 combustion turbine generator 49 MW each and one small self-gen.

The Greater Bay area essentially covers the regions surrounding the San Francisco Bay including Alameda, Contra Costa, Santa Clara, San Mateo, and San Francisco counties. The grid is comprised of 500 kV, 230 kV, and lower voltage transmission lines. Internal generation available to meet RMR requirements consists of various thermal units totaling 7,446 MW, and about 826 MW of QF generation. This amount includes the Moss Landing Power Plant and its expansion, but does not include the Los Medanos Energy Center that already has a 5-year RMR type RMR contract.

The Sierra Area covers the southern portion of Sierra County, and most of El Dorado, Yuba, Sutter, Nevada and Placer Counties. The grid consists of 230 kV, 115 kV and 60 kV transmission lines. Internal generation in the Sierra area consists of 31 hydro generators (total maximum generation = 964 MW), 2 gas turbine (98 MW) and 170 MW of Qualifying Facility (QF) generation.

The Stockton area covers all or portions of Amador, Calaveras, Tuolumne, San Joaquin, and Stanislaus counties. The grid is comprised of 230 kV, 115 kV and 60 kV transmission lines. Internal generation consists of several hydro units totaling 1,462 MW, a few MUNI CT's totaling about 75 MW, two market CT's for about 184 MW, a few small self-gen totaling about 18 MW and about 596 MW of QF generation.

The Fresno area covers all or portions of Fresno, Madera, Mariposa and Merced counties. The grid is comprised of 230 and 115 kV lines. Internal generation consists of several hydro units totaling

1847 MW, non-hydro units totaling 209 MW and about 217 MW of QF generation. There are three RMR sub-areas within the Fresno area that contribute to defining RMR requirements.

Southern California Edison System

The LA Basin area covers all or portions of Santa Barbara, Kern, Tulare, Ventura, Los Angeles, Orange and San Bernardino counties. The grid is comprised of 500, 230 and 115 kV lines. Internal generation consists of several gas-fired units totaling about 12,000 MW, a nuclear plant with a capacity of 2,150 MW, about 1500 MW of hydro and over 3,000 MW of QF generation. There are two RMR sub-areas within the LA Basin area that contribute to defining RMR requirements.

San Diego Gas & Electric System

The San Diego County area covers San Diego County and the southwest portion of Orange County. The grid is comprised of 230 kV and lower voltage transmission lines. Internal generation consists of several thermal units totaling about 1,635 MW, 540 MW of combustion turbines and about 170 MW of QF generation.

Summary of RMR MW requirements

Based on the assumptions and criteria used in this study, each local area and sub-area identified in Section V - 3 was evaluated to identify RMR MW requirements. To meet the RMR Criteria, a minimum amount of MW capacity was determined for each local RMR area and sub-area. A brief description of the results under 2004 peak load conditions for each local area follows, and is summarized on Table VIII-1, page 11. More detailed descriptions of the results are provided in the Appendices.

RMR areas can be defined as one of two types:

The first type is defined as a “Generator Deficient” area. This type of area exhibits violations to the RMR Criteria even when all available generation resources are in service within the area. In this RMR Study, additional analyses were conducted to provide an estimate of the total RMR requirement by finding the generator deficiency (through generator or load proxies) and adding the deficiency to the aggregate generation for each generator deficient RMR area.

The second type is defined as a “Competitive Area”. Here there is more market generation then what is strictly required to run in order to reliably serve the load in this local area.

Table VIII – 1 - MW Requirements[2] to Mitigate RMR Criteria Violations

Local Areas	1998	1999	2000	2001	2002	2003	2004
Humboldt	137.0	121	121	171	320	125	128
Battle Creek	-	43	43	102	99	100	102
North Bay Aggregate	221.2	167	584/362[3]	430	488	524	560
Vaca-Dixon	-	-	-	-	-	154	33
Greater Bay Area	6151.0	8651/7705 [2]	7162/6216 [2]	8870/8125	7940	4700[4]	4087
Sierra Aggregate	-	362	362	398	391	218	288
Stockton Aggregate	-	281	322/272 [2]	365	240	173	301
Fresno Aggregate	1754.1	1334	1198	1934	1877	1896	1558
LA Basin Aggregate	6030.0	6901/4720 [2]	4085/900 [2]	1406/1070	1388	2421[5]	860[7]
San Diego County	1968.0	1968	1968	2163	2302	1747	1888
Total	**16,291.3**	**20,052/16,701** [2]	**15,845/11,442** [2]	**15,839/14,758**	**15,045**	**12,058**	**9,805**
Local Sub-Areas							
North Bay Aggregate							
Eagle Rock		-	-	224	277	239	234
Fulton		-	-	206	261	285	326
Sierra Aggregate							
Placer		-	-	-	-	38	57
Drum-Rio Oso		-	-	-	-	124	173
Colgate		74	74	75	75	56	58
Stockton Aggregate							
Tesla		213	213	238	217	137	251
Valley Springs		43	34	52	12	3	10
Lockeford		25	25	25	11	33	40
Fresno Area							
Panoche		-	-	-	-	-	1476
McCall		-	-	-	-	-	575
Henrietta		-	-	-	-	-	10
Reedley		-	-	-	-	50	52
Herndon		-	-	-	-	-	206
LA Basin							
Eastern		918	640	0	185	0	555
Western[6]		4,607/3,370	3445	1406	1203	0	305[7]

[2] For 1998, MW refers to the maximum unit rating. For 1999-2000, MW refers to generator output represented in the power flow case and used for mitigating RMR Criteria violations. Starting in 2001, MW refers to generator output represented in the power flow case and used for mitigating RMR Criteria violations; generator-deficient RMR areas are further adjusted to account for the deficiency.

[3] The value after the slash mark reflects ISO Board approved (post-LARS) reductions to RMR requirement due to one or more of the following reasons: installation of transmission projects, operating procedures, criteria revisions, and equipment rating changes becoming effective prior to June 1999.

[4] This MW requirement does not include generation that can already be expected to be on-line or contractually dispatched.

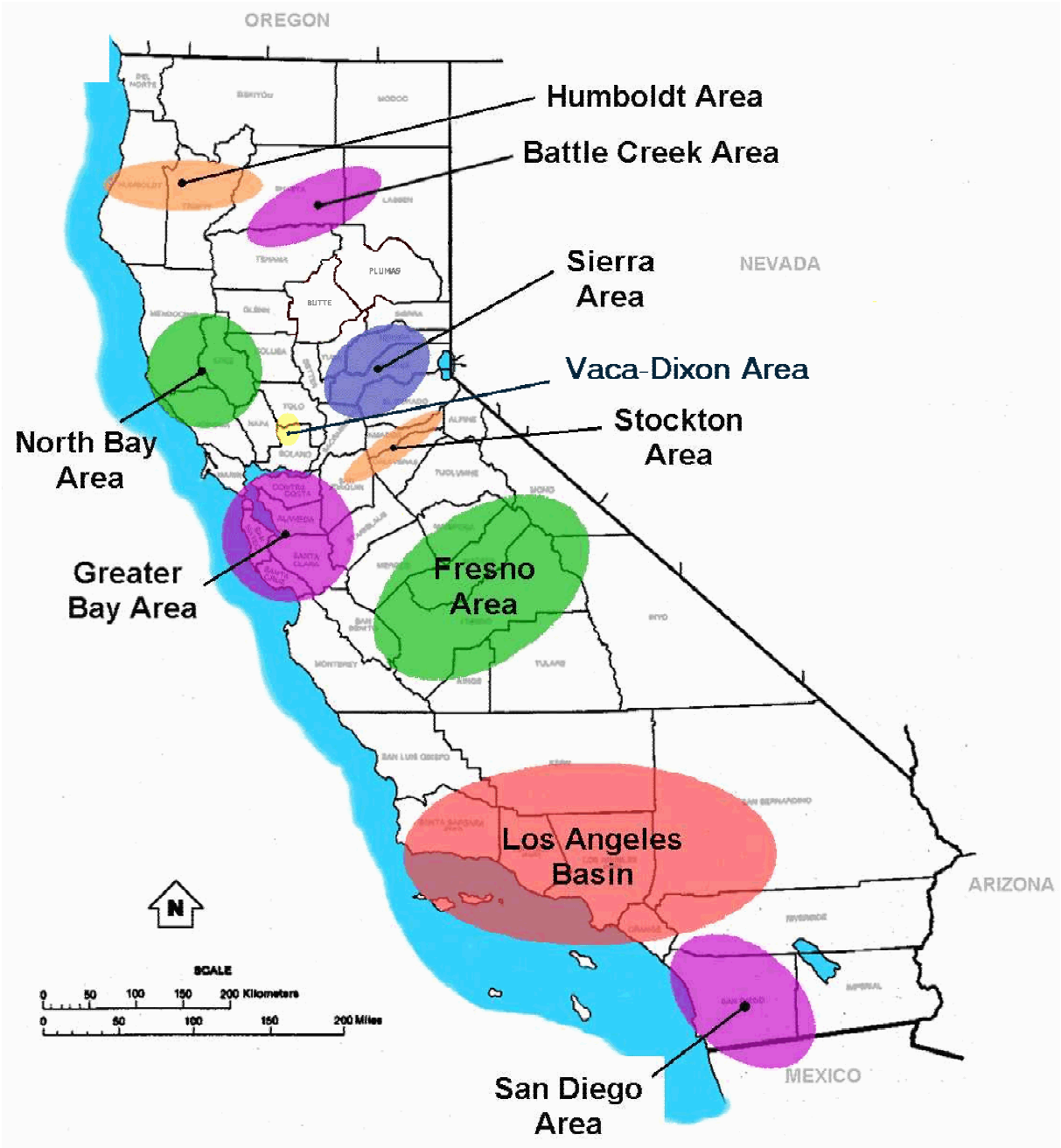
[5] If the Big Creek hydro system is used as first line of defense against the Vincent bank overload – per FERC order, in serving their load SCE has to use their hydro units first – the market RMR requirement decreases to about 1450 MW.

[6] The South Coast and Orange County RMR subareas were merged for 2000 forming the Western RMR subarea.

[7] The RMR requirement for this area is X MW + the single largest unit selected for RMR contract during the LARS process.

10 Current RMR Areas on the ISO-Controlled Grid

Figure 1



IX. Areas Where RMR Requirements Exceed Available Generation

As mentioned under section VIII, some RMR areas experience RMR Criteria violations even when all available generators are operating at full capacity. A RMR area falling under this scenario is referred to as a "Generator Deficient RMR Area." In previous RMR studies, the RMR requirement quoted for a Generator Deficient RMR Area was calculated by taking the sum of MW capacities of all generating units that help relieve the RMR Criteria violation. Consequently, the RMR requirement did not reflect the "total" requirement for these generator deficient RMR areas, but was a reflection of the maximum capacity of available generation. To determine the total requirement, studies would have to either increase existing generating units beyond their effective maximum capacities, add fictitious generation, or decrease load to a point at which the RMR Criteria is just met. Using one of these proxy methods, the difference between the total RMR requirement and the maximum capacity of available generation would provide an estimate of the MW amount of generation deficiency in a particular generator deficient RMR area.

Based on stakeholder interest and ISO Management's recognition that this information is valuable to the marketplace, additional analyses were performed in this RMR Study to determine the RMR requirements and the amount of generation deficiencies for those generator deficient RMR areas. The total RMR requirements for generator deficient RMR areas are reflected in the RMR requirement summary in Table VIII-1. Generation deficiencies for generator deficient RMR areas are summarized in Table IX-1 below.

Table IX – 1: MW Generation Deficiencies in Generator Deficient RMR Areas

Local Areas	2004
Battle Creek	17
North Bay Aggregate	
Eagle Rock	12
Fulton	22
Sierra Aggregate	
Placer	37
Stockton Aggregate	
Lockeford	15
Fresno	
Reedley	13

It should be understood that the values in Table IX-1 above are approximations based on the proxy method described above and should be taken as a general guide only. Specifically, the actual generator deficiency may be significantly different than reported above depending on the actual location of the proposed new generation, since for the most part the values above were derived from decreasing load throughout the entire RMR area or subarea in question.

X. Generator Unit Candidates for RMR Requirements in Competitive Areas

Generating units demonstrating their effectiveness in contributing to the MW requirement were identified. The total number of RMR candidates for the ISO-controlled grid may not be the sum of the units required for each area because some units provide a benefit to more than one area.

For the 2004 time frame, the Greater LA Basin will continue to have more units available than are required. The Ventura area continues to have zero RMR requirements.

In the Western LA Basin area, there are 34 units, namely El Segundo 3-4, Redondo 5-8, and Long Beach 1-9, Harborgen, Alamitos 1-6, Anaheim, Brigen, Coldgen, Growgen, Carbogen, Pulpgen, Harborcogen SRG, and Huntington Beach 1-4 that have a combined capacity of 5,648 MW all available to meet RMR requirements in 2004.

In the Eastern LA Basin Area, there are 6 units, namely Etiwanda 3-4, Wintec X 1-2, Alliance Century and Alliance Drew that have a combined capacity of 840 MW all available to meet RMR requirements in 2004.

The Chico area and the Lakeville subarea continue to have zero RMR requirements for year 2004.

In the Humboldt area, there are 5 candidate units, namely Humboldt Bay #1 and #2, Humboldt GT #1 and #2 and Ultra Power Blue Lake that have a combined capacity of 146 MW that could meet the RMR requirement of 128 MW in 2004.

Due to transmission projects addition parts of the Summit subarea in Sierra will have more units available than required in 2004, with one exception the Placer pocket. Run-of-the-river constraints will be respected during LARS process.

In the Tesla subarea, part of Stockton area, most of the units are not eligible for an RMR contract (MUNI) and they will be considered on-line at their historical values. The Stanislaus river development and the GWF's units at Tracy can satisfy the remaining part of the RMR need.

In the Valley Springs subarea, part of Stockton area, most of the units are not eligible for an RMR contract (MUNI) and they will be considered on-line at their historical values. Depending on availability (based on historical data) of these MUNI units the remaining market unit may or may not be eligible for an RMR contract.

Generating units serving the Greater Bay Area have been historically divided into two groups: "Internal" and "Boundary." Within the 2004 RMR Study boundary generator units located in the Geysers Area and the Gold Country Area are not required to meet the RMR requirement in the Greater Bay Area. In the Greater Bay Area, there are 54 units with a maximum of about 7,446 MW of generation available to meet RMR requirements in 2004.

Although the overall Fresno area is not a generation deficient RMR area for 2004, one of five RMR subareas in Fresno area is generation deficient RMR area in 2004. Run-of-the-river constraints will be respected during LARS process.

In the San Diego Area, there are 34 units with about 2,175 MW of generation available to meet RMR requirements in 2004.

Table X – 1: Units That Are Effective in Mitigating RMR Criteria Violations

Number of Unit Candidates[8]

Local Areas	1998	1999	2000	2001	2002	2003	2004
Humboldt	4	3	5	9	7	5	5
Battle Creek	-	9	9	9	9	10	10
North Bay Aggregate	7	7	18	14	14	17	17
Vaca-Dixon	-	-	-	-	-	1	2
Greater Bay Area	34	120	106-109	91	132[9]	52	54
Sierra Aggregate	-	24	24	26	26	23	25
Stockton Aggregate	-	17	16	19	18	20	19
Fresno Aggregate	22	19-20	18	24	24	30	32
LA Basin Aggregate	22	24-39	14-34	31	48	76[10]	40
San Diego County	28	31	31	31	38	34	34
Local Subareas							
North Bay Aggregate							
Eagle Rock		-	-	8	8	11	11
Fulton		-	-	6	6	6	6
Sierra Aggregate							
Placer		-	-	-	-	4	4
Drum-Rio Oso		-	-	-	-	16	18
Colgate		3	3	3	3	3	4
Stockton Aggregate							
Tesla		12	12	15	15	16	15
Valley Springs		4	2	2	1	3	3
Lockeford		1	1	1	1	1	1
Fresno Area							
Panoche		-	-	-	-	-	20
McCall		-	-	-	-	-	12
Henrietta		-	-	-	-	-	2
Reedley		-	-	-	-	8	8
Herndon		-	-	-	-	-	12
LA Basin							
Eastern		4-9	2-8	0	13	0	6
Western[11]		16-25	12-26	4-16	35	0	34

[8] Unit candidate refers to generating units that can mitigate RMR Criteria violations as demonstrated by technical studies. A unit candidate will go through the Screening Process and if found eligible would be able to compete in the LARS RFP process in which it may or may not be selected to receive an RMR contract.

[9] 39 out of 132 units are also required in other adjacent areas because of their local area RMR requirements and are also shown in these areas number for effective units.

[10] If the Big Creek hydro system is used as first line of defense against the Vincent bank overload – per FERC order, in serving their load SCE has to use their hydro units first – the market RMR unit candidates decreases to 54.

[11] The South Coast and Orange County RMR subareas were merged for 2000 forming the Western RMR subarea.

XI. ISO Study Contacts

Questions or comments the reader may have regarding this RMR Study should be directed to the appropriate ISO staff as indicated below.

Questions regarding the overall study assumptions, criteria, methodology and conclusions:

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