Air Quality (1-30)

Carbon Monoxide Re-Designation

1. *Please provide a status report of the CO re-designation at the District, the California Air Resources Board (CARB) and the United States Environmental Protection Agency (USEPA), and the dates and a schedule of critical milestones (e.g., resolution to proceed with the request by the District Governing Board, the District re-designation request to CARB, the re-designation request from CARB to the US EPA, and a decision by the US EPA).*

Response: A representative of VSE met with USEPA on March 1, 2006, to indicate support for the re-designation request, and inquire about the status of the request. At this time, the District and CARB have submitted to USEPA all the information that USEPA believes is required for it to proceed with approval of the re-designation request. The final submittal from CARB to USEPA occurred on March 2, 2006. Our understanding is that USEPA is finalizing its review of the re-designation request, and commencing the rulemaking process, which will include publication of a proposed rulemaking in the Federal Register, solicitation and response to comments, and publication of a final rulemaking in the Federal Register. This process is expected to take a minimum of six months. We suggest that Staff, as a sister agency, request periodic status reports on the re-designation directly from CARB. VSE appreciates any updates from Staff regarding this issue.

Emission Reduction Credits and Offsets

2. *Please identify ERCs owned by the applicant or any affiliate that the District might require to be surrendered as a condition for participation in the Priority Reserve. Please include the ERC number, the pollutant type and amount in pounds per day, and ERC source location and name.*

Response: At this time VSE has not reached any agreement with sellers of Emission Reduction Credits (ERCs) for any pollutant proposed to be included in the District Priority Reserve rulemaking. However, we urge Staff to rely on the Preliminary Determination of Compliance (PDOC), which will demonstrate how the SVEP would comply with all District Rules including those requiring offsets.

Option Contracts

3. *Please provide option contracts and/or evidence of acquisition of ERCs for the CO, SOx, VOC, and PM_{10} liability of the project.*

Response: At this time, while VSE has continued to pursue negotiations for ERCs, no agreements have been reached. See Response to Data Request #2 above.

ERC Status Report

4. *If the applicant is unable to adequately respond to the Data Request above, please provide a status report starting May 1, 2006 and continuing monthly until the report identifies option contracts and/or evidence of acquisition of ERCs for the CO, SOx, VOC and PM_{10} liability of the project, or the start of the project Air Quality Evidentiary Hearings. The report should be*

specific to each pollutant and provide new information and update information from previous monthly status reports as appropriate. The reports should include:

a. contact names and telephone numbers;

b. company or source names;

c. pollutant credit types and amounts in pounds per day (lbs/day);

d. ERC certificate numbers;

e. the methods of emission reductions (e.g., shutdown, reduction of hours of operation, emission controls, etc.);

f. the status of ERC or option negotiations;

g. prices or potential prices; and,

h. the location of the emission reduction credits.

Response: VSE will prepare the status reports as requested; however, VSE will not provide information on prices or potential prices (Item g) as such prices will be confidential and not relevant to an independent evaluation by Staff.

Priority Reserve

5. *Please provide a status report starting May 1, 2006 and continuing monthly until the rule is revised and adopted by the District Board and the District has approved the project's participation in the Priority Reserve under the revised rule, or until the start of the project Air Quality Evidentiary Hearings. The report should provide new information and update information from previous monthly status reports, and include:*

   a. any additional rule changes and revisions needed to enable the applicant to qualify and participate in a revised Priority Reserve program, and that ensure sufficient quantities of credits are in the program;

   b. steps that the applicant will take to meet the proposed revised rule requirements, including

      i. all existing stationary sources under common ownership (applicant and any affiliate identified by the District) will meet Best Available Retrofit Control Technology (BARCT) and will comply with Section (c)(1) of Rule 1309.1.

      ii. that the applicant has satisfied the due diligence requirement of Section (c)(3) of Rule 1309.1;

      iii. that the applicant will satisfy the 1.2 to 1.0 offset ratio requirement of Section (c)(4) of Rule 1309.1;

      iv. that the project will be fully and legally operating within 3 years of a District Permit to Operate or Commission Decision, pursuant to Section (c)(5) of Rule 1309.1; and

      v. the status of negotiations for power sales contracts with the State of California pursuant to Section (d)(1) of Rule 1309.1.

Response: VSE will file the status report requested. However, it should be noted that Staff has listed items to be included in the status report using the current revision to amend Rule 1309.1. If the revision is further modified, VSE will tailor its status report accordingly. Additionally, the District will be the agency charged with making the demonstration that VSE is qualified to participate in its Priority Reserve program. We anticipate that such demonstration will be contained in the District's Determination of Compliance.

Fine Particulate Matter ($PM_{2.5}$) Mitigation

6. *Please provide proposal(s) to mitigate the facility's potentially significant $PM_{2.5}$ impacts.*

Response: VSE believes that participating in the Priority Reserve will mitigate any potentially significant $PM_{2.5}$ impacts.

Priority Reserve for ($PM_{2.5}$) Mitigation

7. *Please discuss changes in the Priority Reserve necessary to ensure that $PM_{2.5}$ emission reduction credits will be identifiable and available to mitigate project $PM_{2.5}$ emissions.*

Response: VSE is unaware of any changes in the Priority Reserve program relating to $PM_{2.5}$ emission reduction credits.

Local Mitigation Opportunities

8. *Please investigate and report on the potential for local emission reductions and mitigation measures.*

Response: There is currently a disincentive to embark upon a project to investigate and develop local emission reductions and mitigation measures because, while VSE is interested, such novel offsetting approaches typically take significant amounts of time to acquire agency approval. Since the SVEP is responding to the predicted shortage of peaking power in Southern California, time delays in overcoming the regulatory burdens associated with developing emission reductions that are not already banked is not feasible. However, if the Staff knows of any local emission reductions that could be developed that are cost effective and would not cause time delay in obtaining agency approval, SVEP will consider them.

Sulfur Oxides (SOx) RECLAIM Status Report

9. *Please provide a status report, starting May 1, 2006 and continuing monthly until the start of the project Air Quality Evidentiary Hearings, regarding the petition or potential petition that the applicant has filed with the District to participate in the SOx RECLAIM program that includes:*

   a. *the petition itself and supporting documentation that the applicant filed with the District; and,*

   b. *a schedule for review and decision by the District of the application for participation in SOx RECLAIM.*

Response: VSE will provide the status report requested.

Sulfur Oxides (SOx) RTCs

10. *Please provide a list of RECLAIM SOx trading credits (RTC) that the applicant already owns or has under option contract.*

Response: VSE does not currently own or have RECLAIM SOx trading credits under option contract.

Oxides of Nitrogen (NOx) RTCs

11. *Please provide a list of NOx RECLAIM trading credits that the applicant owns or has under option contract.*

Response: VSE does not currently own or have NOx RECLAIM trading credits under option contract.

Sulfur Oxides (SOx) RTC Market

12. *Recent revisions to NOx RECLAIM will reduce NOx RECLAIM trading credits by about 15 percent and probably increase prices from existing levels. Please include in the initial status report above a discussion of how the changes to the NOx RECLAIM market would affect the ability of the applicant to purchase sufficient quantities of NOx RECLAIM trading credits.*

Response: The adjustment to NOx RECLAIM trading credit (RTCs) allocations, adopted by the District Governing Board on January 7, 2005, is phased in over a five-year period. Aggregate 2007 allocations are reduced by 4 tons per day, and aggregate allocations for the years 2008-2011 are reduced by 0.925 tons per day each year. These reductions have already been implemented, and are reflected in current allocations. The reductions do not appear to have had any significant impact on the market for NOx RTCs, and VSE does not believe that the reductions will affect the ability of VSE to acquire sufficient quantity of NOx RTCs to comply with District rules for the SVEP.

Startup Emissions

13. *Please provide assumptions and calculations used to derive the individual turbine start-up emissions for NOx, CO and VOC of 7, 15.4 and 2.1 lbs/event, respectively.*

Response: The startup emissions were based on data provided by GE Energy. This data represents margined average engine emissions and is not guaranteed. To account for the worst potential case, these average emissions were therefore margined an additional 40 percent. For example, the GE Energy start emission datum for NOx of 5 lb/start was adjusted upward by 40 percent to produce 7 lb/start. For CO, the average GE Energy start emission is 11 lb/start, which was margined upward by 40 percent to 15.4 lb/start. VOC emissions were also margined upward by 40 percent, from 1.5 lb/start to 2.1 lb/start.

Shutdown Emissions

14. *Please provide assumptions and calculations used to derive the individual turbine shut down emissions for NOx, CO and VOC of 4.3, 18.2 and 1.6 lbs/event, respectively.*

Response: As with the startup emissions, GE Energy provided emissions data for shutdown as unguaranteed, margined average engine emissions. In this case, a 7 percent margin was added to the shutdown emissions figure that GE Energy provided. Thus, for NOx, the average shutdown emission of 4 lb/shutdown was adjusted upward by 7 percent to 4.3 lb/shutdown. For CO, the 17 lb/shutdown emission estimate was adjusted upward to 18.2 lb/shutdown. Similarly, the GE Energy VOC datum of 1.5 lb/shutdown was adjusted upward to 1.6 lb/shutdown.

Modeling Analysis Input

15. *Please provide an explanation of how the turbine's start-up and shut down emissions and exhaust conditions (i.e., flow rate and temperature) were estimated for inputs into the modeling analysis.*

Response*:* Staff is referred to AFC Section 8.1.2.4.3 (Turbine Startup/Shutdown) and Table 8.1-29 for a complete description of the assumptions used to estimate emissions and exhaust conditions. The exhaust stack characteristics were based upon 50 percent load case.

Revised Analysis

16. *If the start-up and shut down emissions rates and characteristics are revised, please provide a revised modeling analysis showing the facility impacts during start-ups.*

Response: Revised analysis is not necessary, because it was not necessary to revised the startup and shutdown emissions rates or characteristics.

Turbine Commissioning Procedures

17. *Please provide a detailed discussion of turbine commissioning and the procedures to be used to limit the simultaneous operation of turbines that have no, or limited, emissions controls in place.*

Response: GE Energy requires 300 hours of base load operation as a final completion step to the commissioning process. Compliance with the entire commissioning process will be made through the application of fuel-use monitoring, emissions factors, and hours of operation. The applicant expects to have a permit condition that limits the commissioning phases to 394 hours per turbine.

As a result, VSE has revised AFC Table 8.1A-10 (Commissioning Emissions) as Table DR17-1 to reflect the additional hours added to the final phase of commissioning. In addition, a correction was made to the total number of units that would be operational simultaneously in each phase. Originally, Phase 1 had four turbines and Phase 4 had five turbines operating simultaneously. Now, both of these phases will have no more than three turbines operating simultaneously.

TABLE DR17-1
Commissioning Emissions

Commissioning Phase	1	2	3	4	5	6	Total
Water Injection	No	No	50%	Yes	Yes	Yes	
SCR Installed	No	No	No	No	50%	Yes	
CO Catalyst Installed	No	No	No	No	Yes	Yes	
Hours per Unit	20	14	24	12	24	300	394

TABLE DR17-1
Commissioning Emissions

Commissioning Phase	1	2	3	4	5	6	Total
# Units Operating Simultaneously*	3	3	1	3	5	5	
Avg Load %	0	5	50	100	75	100	
NOx lb/hr	91	99	175	81	35	8.1	
CO lb/hr	55	60	168	255	9	12	
VOC lb/hr	2	2	3	5	4	2	
MMBtu/hr - HHV	150	180	500	900.5	700	900.5	
NOx lb/mmscf	641	581	370	95	53	9	
CO lb/mmscf	387	352	355	299	14	14	
VOC lb/mmscf	14	12	6	6	6	2	
Total NOx lbs (5 units)	9,100	6,930	21,000	4,860	4,200	12,150	58,240
Total CO lbs (5 units)	5,500	4,200	20,160	15,300	1,080	18,000	64,240
Total VOC lbs	200	140	360	300	480	3,000	4,480

* Assume this number of units operate simultaneously at condition stated with the remaining units operating at fully commissioned full output conditions.

Natural gas MMBtu/mmscf: 1056
Number of GT Units: 5

Phase	Description
1	Pre-break-in checkout.
2	Controlled break-in run.
3	Water injection commissioning. Assume that water injection is 50% effective.
4	Complete AVR commissioning.
5	SCR commissioning. Assume that NOx SCR is 50% effective and CO catalyst is 100% effective.
6	Full load testing & checkout.

Commissioning Emissions

18. *Please provide the assumptions and calculations deriving the turbine commissioning emissions such as those shown in Table 8.1A-10 and estimate maximum emissions from each turbine and the facility during commissioning.*

Response: The commissioning period was broken into a number of specific phases for each of the following major system commissioning steps:

1. Pre-break-in check-out (full speed-no load with no water injection or catalyst systems in service)

2. Controlled break-in run (low load with no water injection or catalyst systems in service)

3. Water injection commissioning (0-100 percent load with partial water injection and no SCR)

4. Commissioning of Automatic Voltage Regulation (full load with full water injection and no SCR)

5. SCR commissioning (50-100 percent load with full water injection and partial SCR)
6. Full-load testing and checkout (full load with full water injection and full SCR)

The turbine manufacturer (GE Energy) provided estimated commissioning durations and load profiles for each of the phases. Based on CEC experience with commissioning periods often taking longer than originally estimated, a margin was applied to the GE Energy duration estimates. At the various load levels dictated by the commissioning load profiles, estimated emission levels (in ppm) were obtained from a proprietary curve provided by the manufacturer. In general, emission levels (in lb/hr) were estimated by using a ratio of turbine exhaust flow and emission levels (in ppm), as appropriate, between a known condition and the estimated condition.

Baseload Operation

19. *Please provide the steps that the applicant will take to ensure continuous operation at base-load to meet the 300 hours operational requirement.*

Response: Please see the response to Data Request #17.

Emissions Limits

20. *If the operational requirement cannot be reasonably met, please provide discussions and analysis to show whether the facility can meet the turbines' PM and VOC emissions limits identified in the AFC. If these PM and VOC emissions levels cannot be met, please provide new estimates for the turbines' PM and VOC emissions, impacts and offsets.*

Response: No revisions are necessary.

Fuel Sulfur Content

21. *Please provide assurance that the sulfur content of supplied natural gas will not be above 0.25 gr/100scf.*

Response: Natural gas for the power plant facility will be supplied by the Southern California Gas Company (SoCal Gas). Gas quality is regulated by Rule No. 30—Transportation of Customer-Owned Gas (see Attachment AIR-1). Rule No. 30, Section I—Gas Quality limits total fuel sulfur to no more than 0.75 grains/100 scf. In practice, the gas supplier, based on historical fuel analysis data, delivers gas to its customers with fuel sulfur contents well below 0.25 grains per 100 scf (see Response #22 below).

Fuel Sulfur Limit

22. *Please provide the steps the applicant would take to ensure that natural gas that has higher than 0.25 gr/100scf of sulfur will not be used at the facility.*

Response*:* Data derived from SoCal Gas for January through December 2005 at Blythe entry points B1 and B2 indicates that the gas fuel sulfur content averages 0.068 grains per 100 scf or 1.143 ppmv. These averages indicate that, in all likelihood, the maximum gas sulfur content will be well below 0.25 grains per 100 scf, and that the annual average of the delivered gas will also be below the 0.25-grains-per-100 scf (See Attachment AIR-2).

Sulfur Limit Compliance

23. *Please provide the method for ensuring continuous compliance with the sulfur content limits specified for the supplied natural gas fuel.*

Response*:* VSE cannot guarantee fuel quality when it has no control over the fuel supply (origin) or distribution and mixing network, etc. VSE is committed to using clean burning natural gas which, based, on historical data and future expectations, will continue to be extremely low in total sulfur content, resulting in low emissions of SO_2. In addition, the data noted above and presented in Attachment AIR-2 indicates that the overall average gas sulfur content is well below the 0.25-grains-per-100 scf value quoted in the AFC, which means that the actual SO_2 emissions will most likely be less than those stated in the AFC on an annual basis. VSE will rely upon SoCal Gas to ensure that the gas supplied to the plant (as well as to all the remaining gas customers) is the highest quality; i.e., having the lowest possible fuel sulfur contents. In addition, the facility will evaluate the need for a program of periodic on-site gas fuel sampling and analysis to determine compliance with the stated gaseous fuel sulfur value or 0.25 grains per 100 scf. Pursuant to NSPS Subpart KKKK (new turbines greater than or equal to 1 MW and constructed after February 18, 2005) section 60.4365, the SVEP turbines would not need to monitor (sample and analyze) fuel for sulfur content since the current tariff and transportation sheet for the proposed natural gas (Rule 30 as attached) insures that the gas sulfur content will be well below the 300-ppmw NSPS Subpart KKKK limit.

Ultra-Low Sulfur Diesel

24. *Please provide discussion about the feasibility of using ultra-low sulfur diesel as fuel for the fire pump engines.*

Response: VSE proposes to use ultra-low sulfur diesel, which contains no more than 15 ppm sulfur (0.0015 percent S by weight), for the fire pump engine.

Emissions Using Ultra-Low Sulfur Diesel

25. *Given the scenario of using ultra-low sulfur diesel, please revise project emissions, and if appropriate, air dispersion modeling, based on the new fuel.*

Response: No revisions to the modeling are needed, as the modeling assumed that the fire-pump engine would use ultra-low sulfur fuel. Air quality impacts from the use of the proposed diesel fuel with a sulfur content of 0.015 percent by weight are insignificant; i.e., downwind impact values do not violate any SIL, nor do they cause or contribute a violation of any SO_2 air quality standard. As such, the use of ultra-low sulfur diesel fuel will also have insignificant impacts on local and regional SO_2 air quality.

Text File

26. *Please provide a text file describing the provided input and output modeling files.*

Response: A “readme” file will be supplied which identifies the various modeling input and output files.

Cumulative Impacts Analysis

27. *Please clarify whether an air quality cumulative impact analysis has been performed. If it has, please provide the modeling assumptions, model input and output files, and modeling results.*

Response: The source inventory file necessary for the completion of the cumulative impact analysis has been requested from the South Coast AQMD. Upon receipt and QA/QC of the data, the source list will be supplied to CEC staff, and the cumulative analysis will be prepared and forwarded to staff and the AQMD.

List of Projects

28. *If a cumulative impact analysis has not been performed, please discuss the status of obtaining a list of projects near the Sun Valley project site that meet the criteria listed in Section 8.1H "Cumulative Impacts Analysis Protocol". If the aforementioned list has been obtained, please submit the list of the emission sources to be included in the cumulative air quality impacts analysis.*

Response: See the response to Data Request #27, above.

Cumulative Impacts Modeling

29. *Upon staff's review and concurrence of the sources, please perform a cumulative impact analysis using the modeling method proposed in the AFC.*

Response: See the response to Data Request #27, above.

Offsets Required

30. *Please provide a table that lists the correct amount of offsets required by the District's NSR rule.*

Response: AFC Table 8.1G-2 is revised as follows (Table DR30-1):

TABLE DR30-1
SCAQMD Emission Bank Credits Required By SVEP Emission Reduction Credits

	PM_{10} lbs/month	VOC lbs/month	CO lbs/month	NOx RTCs lbs/yr	SOx RTCs or ERCs lbs/yr
Total Mitigation Amounts Required	16,118.5	6,403	37,403	149,540	10,760

Values derived from AFC Appendix 8.1A, Table 8.1A-2a, with 1.2:1 adjusted for ERCs only.

Attachment AIR-1

SoCal Gas Rule #30

Rule No. 30 Sheet 1 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

The provisions of this Rule shall not apply to service until the date of full implementation of the CPUC's Capacity Brokering Rules set forth in Decision Nos. 91-11-025 and 92-07-025 and Resolution Nos. G-3023, G-3033 and G-3043.

The general terms and conditions applicable whenever the Utility transports customer-owned gas over its system are described herein.

A. General

1. Subject to the terms, limitations and conditions of this rule and any applicable CPUC authorized tariff schedule, directive, or rule, the customer will deliver or cause to be delivered to the Utility and accept on redelivery quantities of customer-owned gas which shall not exceed Utility's capability to receive or redeliver such quantities. Utility will accept such quantities of gas from the customer or its designee and redeliver to the customer on a reasonably concurrent basis an equivalent quantity, on a therm basis, to the quantity accepted.

2. The customer warrants to the Utility that the customer has the right to deliver the gas provided for in the customer's applicable service agreement or contract (hereinafter "service agreement") and that the gas is free from all liens and adverse claims of every kind. The customer will indemnify, defend and hold the Utility harmless against any costs and expenses on account of royalties, payments or other charges applicable before or upon delivery to the Utility of the gas under such service agreement.

3. The point(s) where the Utility will receive the gas into its intrastate system (point(s) of receipt, as defined in Rule No. 1) and the point(s) where the Utility will deliver the gas from its intrastate system to the customer (point(s) of delivery, as defined in Rule No. 1) will be set forth in the customer's applicable service agreement. Other points of receipt and delivery may be added by written amendment thereof by mutual agreement. The appropriate delivery pressure at the points of delivery to the customer shall be that existing at such points within the Utility's system or as specified in the service agreement.

B. Quantities

1. The Utility shall as nearly as practicable each day redeliver to customer and customer shall accept, a like quantity of gas as is delivered by the customer to the Utility on such day. It is the intention of both the Utility and the customer that the daily deliveries of gas by the customer for transportation hereunder shall approximately equal the quantity of gas which the customer shall receive at the points of delivery. However, it is recognized that due to operating conditions either (1) in the fields of production, (2) in the delivery facilities of third parties, or (3) in the Utility's system, deliveries into and redeliveries from the Utility's system may not balance on a day-to-day basis. The Utility and the customer will use all due diligence to assure proper load balancing in a timely manner.

(Continued)

Rule No. 30 Sheet 2

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

B. Quantities (continued)

2. The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow. Utility may refuse to accept fluctuations in excess of ten percent (10%) of the previous day's deliveries, from day to day, if in the Utility's opinion receipt of such gas would jeopardize other operations. Customers may make arrangements acceptable to the Utility to waive this requirement.

3. The Utility does not undertake to redeliver to the customer any of the identical gas accepted by the Utility for transportation, and all redelivery of gas to the customer will be accomplished by substitution on a therm-for-therm basis.

4. Transportation customers, contracted marketers, and aggregators will be provided monthly balancing services in accordance with the provisions of Schedule No. G-IMB.

5. Gas shall be transported hereunder for use only by the customer within the state of California, and not for delivery or resale to a third party unless authorized by the Commission.

C. Electronic Bulletin Board T

1. SoCalGas prefers and encourages customers to use Electronic Bulletin Board (EBB) as defined in Rule No. 1 to submit their transportation nominations to the Utility. Imbalance trades are to be submitted through EBB or by means of the Imbalance Trading Agreement Form (Form 6544). Charges for EBB are set forth in Rule No. 33 and are based upon the level of actual usage. Use of EBB is not mandatory for transportation only customers. T

D. Operational Requirements

1. The customer must provide to the Utility the name(s) of its shipper(s) as well as any brokers or agents ("agent") used by the customer for delivery of gas to the Utility for transportation service hereunder and their authority to represent customer.

2. Transportation nominations may be submitted manually or through EBB. For each transportation nomination submitted manually, (by means other than EBB such as facsimile transmittal), a processing charge of $11.87 shall be assessed. No processing charge will apply to an EBB subscriber for nominations submitted by fax at a time the EBB system is unavailable for use by the subscriber. T

(Continued)

D. Operational Requirements (continued)

3. Transportation nominations submitted via EBB for the Timely Nomination cycle must be received by the Utility by 9:30 a.m. Pacific Clock Time one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 8:30 a.m. Pacific Clock Time one day prior to the flow date. Nominations received after the nomination deadline will be processed after the nominations received before the nomination deadline. All nominations are considered original nominations and should be replaced to be changed. T

   Nominations submitted via EBB for the Evening Nomination cycle must be received by the Utility by 4:00 p.m. Pacific Clock Time one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 3:00 p.m. Pacific Clock Time one day prior to the flow date. T

   Nominations submitted via EBB for the Intraday 1 Nomination cycle must be received by the Utility by 8:00 a.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 7:00 a.m. Pacific Clock Time on the flow date. T

   Nominations submitted via EBB for the Intraday 2 Nomination cycle must be received by the Utility by 3:00 p.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 2:00 p.m. Pacific Clock Time on the flow date. T

   Evening and Intraday nominations may be used to request an increase or decrease to scheduled volumes or a change to receipt or delivery points.

4. Where gas is transported by a shipper or agent to more than one customer of the Utility and the transporting pipeline's allocation to the shipper or agent is less than the shipper's or agent's requested quantity, such shipper or agent must allocate among its customers the total quantity of gas delivered each day to the Utility by the shipper or agent.

   An allocation ranking must be submitted to the Utility no later than 3:00 p.m. Pacific Clock Time on the date of flow. An allocation ranking should be received for each flow date from each shipper. Agent rankings should be submitted along with the nominations.

   If no allocation ranking is made by such shipper or agent by the due date and time, the Utility will use a pro rata allocation in allocating delivered quantities among the shipper's or agent's customers and the Utility's allocation of these quantities will prevail. The total quantity allocated among the customers of a shipper or agent during a month shall be adjusted by the Utility if necessary to match the actual monthly delivery to the Utility for the shipper or agent as reported by the transporting pipeline.

Rule No. 30 Sheet 4
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

5. As between the customer and the Utility, the customer shall be deemed to be in control and possession of the gas to be delivered hereunder and responsible for any damage or injury caused thereby until the gas has been delivered at the point(s) of receipt. The Utility shall thereafter be deemed to be in control and possession of the gas after delivery to the Utility at the point(s) of receipt and shall be responsible for any damage or injury caused thereby until the same shall have been redelivered at the point(s) of delivery, unless the damage or injury has been caused by the quality of gas originally delivered to the Utility, for which the customer shall remain responsible.

6. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by the responsible customer.

7. Customers receiving service from the Utility for the transportation of customer-owned gas shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.

E. Interruption of Service

1. The customer's transportation service priority shall be established in accordance with the definitions of Core and Noncore service, as set forth in Rule No. 1, and the provisions of Rule No. 23, Continuity of Service and Interruption of Delivery. If the customer's gas use is classified in more than one service priority, it is the customer's responsibility to inform the Utility of such priorities applicable to the customer's service. Once established, such priorities cannot be changed during a curtailment period.

2. The Utility shall have the right, without liability (except for the express provisions of the Utility's Service Interruption Credit as set forth in Rule No. 23), to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation. When doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.

F. Nominations in Excess of System Capacity

1. In the event the Utility determines that the transportation nominations received for a specific date of gas flow ("flow date") exceed its expected system capacity (including storage) on such flow date, the Utility shall apply Buy-Back service under Schedule No. G-IMB separately for each flow date that is overnominated. In such event, the Utility shall follow the procedure set forth below. This procedure and the resulting periods of excess nominations shall apply only to (1) all noncore transportation customers, and (2) all customers with usage exceeding 250,000 therms per year at each facility D
served under Schedule Nos. GT-10 and GT-NGV.

(Continued)

F. Nominations in Excess of System Capacity (continued)

2. If the Utility determines that transportation nominations received for a specific flow date will result in a period of excess nominations, the Utility shall effectuate at such time a reduction of Hub services that would contribute to the overnomination event and as-available storage injection nominations made for service under Schedule No. G-AUC. Such reductions shall be made in the order of the as-available service queue.

3. If such reductions in nominations are inadequate in resolving the excess transportation nominations problem, Utility shall notify all applicable customers that an excess nominations period shall be instituted. The Utility shall provide such notice via its EBB system. T

4. The excess nominations period shall begin on the flow date(s) indicated by the Utility. Nominations for customers without automated meter reading devices will be reduced to the maximum daily quantity specified for the customer. Customers shall be allowed to reduce their nominations in response to the Utility's notification. Such nominations reductions must be received by the Utility within two (2) business hours from the Utility's notification. If such voluntary reductions are adequate to bring the system into balance, the overnomination flow date will be canceled. Nomination reductions received after this deadline shall be considered received for the next day's nominations.

5. In the event customers fail to adequately reduce their transportation nominations, the Utility shall reduce the nominations of those customers that the Utility believes are causing the excess nominations problem. In making such nominations reductions, the Utility shall utilize the most recent and best available operating data at its disposal.

6. In cases where the Utility reduces a customer's nomination under the above procedure and, as a result of such reduction, the customer uses Standby Procurement service under Schedule No. G-IMB in excess of the 10% tolerance band, the customer shall be allowed to additionally carry over the lesser of (1) the negative imbalance for the month in excess of the tolerance band, or (2) the amount of the customer's total involuntary nominations reductions for the month. Such additional carryover shall be applied to the customer's imbalance account at the conclusion of the imbalance trading period for the month in which the involuntary reduction occurred.

7. In accordance with the provisions of Schedule No. G-IMB, Buy-Back service shall be applied separately to each excess nominations day. Customer meters subject to maximum daily quantity limitations will use the maximum daily quantity as a proxy for daily usage. For each such day, the Utility shall apply the applicable Buy-Back rate to all of the customer's deliveries, less any firm storage injections made on behalf of the customer, for the designated flow date that are in excess of 110% of the customer's actual usage.

(Continued)

F. Nominations in Excess of System Capacity (continued) L

8. Consistent with the requirements of Decision No. 92-07-025, the Utility's Gas Supply Department shall limit its deliveries into its system on behalf of its core sales market to no more than 110% of actual gas usage for the core (including firm storage injections on behalf of the core) during periods of excess transportation nominations. L

G. Winter Deliveries

The Utility requires that customers deliver (using a combination of flowing supply and firm storage withdrawal) at least 50% of burn over a five day period from November through March. As the Utility's total storage inventory declines through the winter, the delivery requirement becomes daily and increases to 70% or 90% depending on the level of inventory relative to peak day minimums.

1. From November 1 through March 31 customers are required to deliver (flowing supply and firm storage withdrawal) at a minimum of 50% of burn over a 5-day period. In other words, for each 5-day period, the Utility will calculate the total burn and the total delivery. If the total delivery is less than 50% of the total burn, a daily balancing standby charge is applied. The daily balancing standby rate is 150% of the highest Southern California Border price during the five day period as published by Natural Gas Intelligence in "NGI's *Daily* Gas Price Index," including authorized franchise fees and uncollectible expenses (F&U) and brokerage fees. Imbalance trading and as-available withdrawals may not be used to offset the delivery minimums. As an additional requirement, retail core and core aggregation will deliver a volume no less than 50% of their allocated firm interstate pipeline rights.

   a. "Burn" means usage and is defined as metered throughput or an estimated quantity such as Minimum Daily Quantity (MinDQ), as defined in Rule No. 1, for customers without automated meters.

   b. Example five-day periods are: Nov. 1 through Nov. 5, Nov. 6 through Nov. 10, Nov. 11 through Nov. 15 and so on. November with 30 days has six 5-day periods. December, January and March with 31 days have a 6-day period at the end of the month. February has a shortened 3 or 4-day period at the end of the month. The current 5-day period will run its course fully before the implementation of the 70% daily requirement. In the event that inventories rise above the 70% daily trigger levels by 1 Bcf, then a new, 5-day period will be implemented on the following day.

   c. Example calculations for determining volumes subject to the daily balancing standby rate are: if over 5 days, total burn is 500,000 therms and total deliveries (including firm withdrawal) are 240,000 therms, then 10,000 therms is subject to daily balancing standby rate. (50% times 500,000 minus 240,000 equals 10,000).

L

(Continued)

G. Winter Deliveries (continued)

1. (continued)

   d. Example calculations in using NGI's Daily Gas Price Index for determining the daily balancing standby rate are: If for Jan. 6 through Jan. 10 the NGI Southern California Border quoted price ranges are $2.36- 2.39, $2.36-2.44, $2.38-2.47, $2.36-2.42, and $2.37- 2.45, respectively, then the daily balancing standby rate becomes $3.71 ($2.47 times 150%). L

   e. With the exception of weekends and holidays, the Utility will use quotes from the NGI publication dated on the same day as the flow date. Weekend or holiday flow dates will use the first available publication date after the weekend or holiday.

   f. Under current capacity assignments, 50% of core (retail core plus core aggregation) interstate pipeline rights translates to 522 MMcfd. For aggregators this translates to 50% of the Daily Contract Quantity (DCQ) as defined in Rule No. 1.

2. When total inventory declines to the "peak day minimum + 20 Bcf trigger," the minimum daily delivery requirement increases to 70%. Customers are then required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 70% of burn on a daily basis. The 5-day period no longer applies since the system can no longer provide added flexibility. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees) and is applied to each day's deliveries which are less than the 70% requirement. In this regime as-available storage withdrawal is cut in half. All Hub activity contributing to the underdelivery situation (i.e., Hub deliveries greater than Hub receipts) is suspended.

   a. Peak day minimums are calculated annually before November 1 as part of normal winter operations planning. The peak day minimum is that level of total inventory that must be in storage to provide deliverability for the core 1-in-35 year peak day event, firm withdrawal commitments and noncore balancing requirement.

   b. Example calculations in this regime for determining volumes subject to the daily balancing standby rates are: If on January 6 total burn is 500,000 therms, and total deliveries (including firm withdrawal) are 300,000 therms then 50,000 therms is subject to the daily balancing standby charge (70% times 500,000 minus 300,000 equals 50,000).

   c. Example calculations in using NGI's Daily Gas Price Index for daily balancing standby rates in this regime are: if for January 6 and January 7, the NGI Southern California Border quoted price ranges are $2.36-2.39 and $2.36-2.44, then the daily balancing standby rates become $3.59 (150% of 2.39) for January 6, and $3.66 (150% times 2.44) for January 7, respectively.

(Continued)

G. Winter Deliveries (continued)

3. When total inventories decline to the "peak day minimum + 5 Bcf trigger," the minimum daily delivery requirement increases to 90%. Customers are required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 90% of burn on a daily basis. Similar to the 70% regime the 5 day period no longer applies. The daily balancing standby rate is charged daily and is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees). In this regime there are no as-available storage withdrawals. All Hub activity contributing to the underdelivery situation (i.e., Hub deliveries greater than Hub receipts) is suspended.

4. Information regarding the established peak day minimums, daily balancing trigger levels and total storage inventory levels will be made available to customers on a daily basis via EBB and other customer notification media. T

5. If a wholesale customer so requests, the Utility will nominate firm storage withdrawal volumes on behalf of the customer to match 100% of actual usage assuming the customer has sufficient firm storage withdrawal and inventory rights to match the customer's supply and demand.

6. The Utility will accept intra-day nominations to increase deliveries.

7. In all cases, current BCAP rules for monthly balancing and monthly imbalance trading continue to apply. Volumes not in compliance with the 50%, 70% and 90% minimum delivery requirements, purchased at the daily balancing standby rate, are credited toward the monthly 90% delivery requirements. Daily balancing charges remain independent of monthly balancing charges. Daily balancing and monthly balancing charges go to the Purchased Gas Account (PGA). Schedule No. G-IMB provides details on monthly and daily balancing charges.

H. Accounting and Billing

1. The customer and the Utility acknowledge that on any operating day during the customer's applicable term of transportation service, the Utility may be redelivering quantities of gas to the customer pursuant to other present or future service arrangements. In such an event, the Utility and customer agree that the total quantities of gas shall be accounted for in accordance with the provisions of Rule No. 23. If there is no conflict with Rule No. 23, the quantities of gas shall be accounted for in the following order:

Rule No. 30 Sheet 9
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

H. Accounting and Billing (continued)

1. (continued)

   a. First, to satisfy any minimum quantities under existing agreements.

   b. Second, after complete satisfaction of (a), then to any supply or exchange service arrangements with the customer.

   c. Third, after the satisfaction of (a) and (b), then to any subsequently executed service agreement.

2. The customer agrees that it shall accept and the Utility can rely upon, for purposes of accounting and billing, the allocation made by customer's shipper as to the quality and quantity of gas, expressed both in Mcf and therms, delivered at each point of receipt during the preceding billing period for the customer's account. If the shipper does not make such an allocation, the customer agrees to accept the quality and quantity as determined by the Utility. All quality and measurement calculations are subject to subsequent adjustment as provided in the Utility's tariff schedules or applicable CPUC rules and regulations. Any other billing correction or adjustment made by the customer or third party for any prior period shall be based on the rates or costs in effect when the event occurred and accounted for in the period they are reconciled.

3. The Utility shall render to the customer an invoice for the services hereunder showing the quantities of gas, expressed in therms, delivered to the Utility for the customer's account, at each point of receipt and the quantities of gas, expressed in therms, redelivered by Utility for the customer's account at each point of delivery during the preceding billing period. The Customer shall pay such amounts due hereunder within nineteen (19) calendar days following the date such bill is mailed.

4. Both the Utility and the customer shall have the right at all reasonable times to examine, at its expense, the books and records of the other to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to service hereunder. The Utility and the customer agree to keep records and books of account in accordance with generally accepted accounting principles and practices in the industry.

I. Gas Quality

1. The gas stream delivered by the customer into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements, contracts, service contracts and tariff schedules in effect between the delivering interstate or intrastate pipeline and the Utility at the time of the delivery. T

(Continued)

I. Gas Quality (continued)

2. All gas delivered into the Utility's system for the account of the customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt and shall conform to the following minimum specifications:

   a. Heating Value: The minimum heating value is nine hundred and seventy (970) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis. T,N N

   b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20F at delivery pressure. T | | T

   c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide per one hundred (100) standard cubic feet. The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.

   d. Mercaptan Sulfur: The mercaptan sulfur is not to exceed three tenths (0.3) grains per hundred standard cubic feet.

   e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds per one hundred (100) standard cubic feet. This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.

   f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.

   g. Oxygen: The gas shall not at any time have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.

   h. Inerts: The gas shall not at any time contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

   i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20F at a pressure of 400 psig. T | | T

(Continued)

I. Gas Quality (continued)

2. (continued)

j. Dust, Gums and Other Objectionable Matter: The gas shall be commercially free from dust, gums and other foreign substances.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50F or above 105F.

m. Interchangeability: The gas shall meet American Gas Association's Wobbe Number, Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system near the points of receipt. Acceptable specification ranges are:

* Wobbe Number (W for receiving facility)
(WP for producer)
0.9 W <= WP< = 1.1 W T

* Lifting Index (IL)
IL <= 1.06

* Flashback Index (IF)
IF <= 1.2

* Yellow Tip Index (IY)
IY >= 0.8

* Specifications are in relation to a typical composition of gas serving the area to be supplied by the new source.

3. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications as set out in I. 1 and I. 2 above, as applicable.

(Continued)

J. Termination or Modification L

1. If the customer breaches any terms and conditions of service of the customer's service agreement or the applicable tariff schedules and does not correct the situation within thirty (30) days of notice, the Utility shall have the right to cease service and immediately terminate the customer's applicable service agreement.

2. If the contract is terminated, either party has the right to collect any quantities of gas or money due them for transportation service provided prior to the termination.

K. Regulatory Requirements

1. Any gas transported by the Utility for the customer which was first transported outside the State of California shall have first been authorized under Federal Energy Regulatory Commission (FERC) regulations, as amended. Both parties recognize that such regulations only apply to pipelines subject to FERC jurisdiction, and do not apply to the Utility. The customer shall not take any action which would subject the Utility to the jurisdiction of the FERC, the Economic Regulatory Administration or any succeeding agency. Any such action shall be cause for immediate termination of the service arrangement between the customer and the Utility.

2. Transportation service shall not begin until both parties have received and accepted any and all regulatory authorizations necessary for such service. L

L. Warranty and Indemnification

1. The customer warrants to the Utility that the customer has the right to deliver gas hereunder and that such gas is free from all liens and adverse claims of every kind. Customer will indemnify, defend and save Utility harmless against all loss, damage, injury, liability and expense of any character where such loss, damage, injury, liability or expense arises directly or indirectly out of any demand, claim, action, cause of action or suit brought by any person, association or entity asserting ownership of or any interest in the gas tendered for transportation hereunder, or on account of royalties, payments or other charges applicable before or upon delivery of gas hereunder.

2. The customer shall indemnify, defend and save harmless Utility, its officers, agents, and employees from and against any and all loss, costs (including reasonable attorneys' fees), damage, injury, liability, and claims for injury or death of persons (including any employee of the customer or the Utility), or for loss or damage to property (including the property of the customer or the Utility), which occurs or is based upon an act or acts which occur while the gas is deemed to be in the customer's control and possession or which results directly or indirectly from the customer's performance of its obligations arising pursuant to the provisions of its service agreement and the Utility's applicable tariff schedules, or occurs based on the customer-owned gas not meeting the specifications of Section I of this rule.

Attachment AIR-2

Sulfur Gas Tables

SOUTHERN CALIFORNIA GAS COMPANY

Sun Valley Energy Project

From 01/05 to 12/05 (grains S/100 cf)

Out of State Suppliers	H_2S			RSH			Total Sulfur*		
Location	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg
B1	0.000	0.018	0.007	0.027	0.115	0.060	0.042	0.131	0.067
B2	0.000	0.018	0.005	0.030	0.130	0.064	0.046	0.145	0.069
Note: the Blythe entry points B1 and B2 are the most appropriate for the SVEP.									

Overall Avg: 0.068
grains S/100 scf

From 01/05 to 12/05 *(ppmv S)*

Out of State Suppliers	H_2S			RSH			Total Sulfur*		
Location	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg
B1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
B2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Note: the Blythe entry points B1 and B2 are the most appropriate for the SVEP.									

Overall Avg: 0.000
ppmv S

Assuming 16.9 ppm = 1 grains S/Ccf

* Includes estimated supplemental odorant based on border guidelines of 50/50 t-butyl mercaptan/thiophane

** SoCalGas Specifications allow up to 0.25 gr.H_2S/100scf and 0.75 gr. S/100scf Total Sulfur