Application No: A.08-02-001
Exhibit No.:
Witness: Rodger Schwecke

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	)	A.08-02-001 (Filed February 4, 2008)

PREPARED REBUTTAL TESTIMONY

OF RODGER SCHWECKE

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
January 27, 2009

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My name is Rodger R. Schwecke. I am employed by the Southern California Gas Company (SoCalGas) as the Director, Energy Markets and Capacity Products for SoCalGas and San Diego Gas & Electric (SDG&E). My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I have testified previously in this proceeding.

The purpose of my testimony is to respond to intervenor testimony in order to:

- Reemphasize SDG&E/SoCalGas' rationale supporting various proposal specifics.
- Correct statements by intervenors that err in describing aspects of the proposals.
- Encourage the Commission to adopt SDG&E/SoCalGas' proposals.

Specifically I will address the following topics:

- Intervenors' misunderstanding of the Utility System Operator function.
- Reasons for the southern system minimum flowing supply requirements.
- Lack of validity of the comparison between SoCalGas/SDG&E's operation of their pipeline system and the functions of the California ISO.
- Existence of FERC and CPUC rules providing for oversight of gas pipeline operations.
- Reasonableness of the Southern System Flow Order proposal as a tool to be used by SDG&E/SoCalGas in support of the minimum flowing gas requirements on the southern system.
- Adequacy of current market transparency and posting requirements, both for minimum flowing supply purchases and Operational Hub transactions.
- Proposals for a stakeholder forum, similar to PG&E's OFO Forum, which could, if properly structured, provide additional insight to intervenors on the operational realities of SDG&E/SoCalGas' system, provide a forum for discussing alternatives and suggestions to tools used to support system operation and address the transparency concerns regarding system operations.

- Difficulty associated with the use of the hindsight reasonableness review process with potential disallowance of costs.
- Adequacy of existing pipeline and storage operational procedures, the formula in place for calling OFOs and the proposal for determining the quantity of additional gas supplies for the southern system minimum.
- Appropriateness of the standard Advice Letter process to propose additional tools to support the southern system minimum.
- Effectiveness of the SoCalGas proposed transmission rate design (TLS), which is not overly burdensome, mirrors what customers would receive on an interstate pipeline, complies with the Commission's order to close or sufficiently narrow the "regulatory gap" between the utilities' rates and those of interstate pipelines, and allows SoCalGas to eliminate the Peaking Service tariff (Schedule GT-PS).[1]
- Support for SDG&E/SoCalGas' proposal to require a six-year term for full requirements, all-volumetric, firm service.
- Continued support of the Sempra-wide rates for electric generation customers that are served off of SDG&E/SoCalGas' distribution pipelines.
- Appropriateness of the proposed treatment of the state regulatory surcharge for electric generation customers as it may apply to generation purchased by an electric utility that does not physically own the generation plant.
- Continued support of the revenue treatment for EOR customers.
- Proposal to modify SDG&E/SoCalGas' proposed allocation of transmission costs to the backbone.

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[1] D.06-12-031, p. 143, O.P. 9(a) "In its next Biennial Cost Allocation Proceeding (BCAP), SoCalGas shall include a proposal for a total redesign of its rate consistent with the discussion regarding closing or minimizing the regulatory gap" and 9(b) as modified by D.07-09-046, p. 25, O.P. 2. 9(b) "At the conclusion of SoCalGas' next BCAP, we intend to sunset the existing peaking rate tariff." Also, see discussion in D.06-12-031, p.129. "A wholesale change in rate design may be needed if parties want to truly resolve the peaking rate issue, promote pipe-to-pipe competition, and protect the captive customers who remain on the system."

I. The Role of the Utility System Operator

It appears from the testimony submitted by intervenors that some degree of confusion exists regarding the structure and operation of the Utility System Operator. Certain parties appear to assume that the Utility System Operator is a discrete operational group within SoCalGas that is solely responsible for the specific functions assigned to the Utility System Operator. This is incorrect. The concept of the Utility System Operator was introduced in the Omnibus proceeding (A.06-08-026) to generally describe various functions within SDG&E/SoCalGas that support providing reliable service to customers, specifically excluding the gas procurement function. As presented and approved by the Commission in SoCalGas Advice Letter 3818-A, the term "Utility System Operator" is defined in SoCalGas' Rule 1 as follows:

> Utility System Operator: The applicable departments within Southern California Gas Company and San Diego Gas & Electric Company that are responsible for the physical and commercial operation of the pipeline and storage systems specifically excluding the Utility Gas Procurement Department.

Thus, the term "Utility System Operator" is an umbrella term that generally refers to and includes multiple functions within SDG&E/SoCalGas' operations that play a role in ensuring safe and reliable service to customers. The term "System Operator" has also been used by SDG&E/SoCalGas and is synonymous with "Utility System Operator."

In order to eliminate confusion as to the structure of the Utility System Operator, SDG&E/SoCalGas provide the following summary of the reporting relationships and certain specific functions of the Utility System Operator:

The daily overall physical transmission and storage system reliability operations within the Utility System Operator are conducted by the existing Gas System Operations (formerly Pipeline System and Planning Department) under Ms. Gina Orozco-Mejia. Gas System Operations, and other various departments that assist in ensuring the operational reliability of the pipeline system and service to customers, are located in the Gas Operations Organization under Mr. Lee Stewart. The Operational Hub's responsibilities, in support of maintaining physical flowing gas supplies, as defined by the Gas System Operations Department, are conducted in Energy Markets and Capacity Products Department under Mr. Rodger Schwecke. The Energy Markets and Capacity Products Department is located in the Customer Services Organization under Mr. Rick Morrow. Within SDG&E/SoCalGas' reporting structure, these two departments do not fall under the same executive responsibility until the level of SDG&E/SoCalGas' President and CEO.

Specifically Gas System Operations is made up of the following:

- SCADA - Maintain the primary data acquisition & control (SCADA) System for the SDG&E/SoCalGas gas transmission and storage system.
- Gas Control - Control and monitor day to day/hour to hour physical gas deliveries into and throughout southern California for the SDG&E/SoCalGas gas transmission system.
- Gas Scheduling - Operate the day to day systems which allow customers to schedule gas supply into SDG&E/SoCalGas.
- Gas Transmission Planning - Long term planning & design of the SDG&E/ SoCalGas gas transmission system.

Specifically, the Capacity Products Department is made up of the following:

- Pipeline Products – Negotiate and administer interconnect agreements and relationships with upstream pipelines/suppliers. Manage the contractual arrangements for receipt point services and other transportation services with customers including potential pipeline expansions. Develop and maintain the gas nominations/scheduling procedures and the electronic bulletin board (EBB) functionality.
- Storage Products – Negotiate and administer unbundled storage and Operational Hub (G-PAL) agreements with customers including potential expansions. Administer any contracts approved by the Commission and obtain additional

supplies in support of the minimum flowing supply needs on the southern system as defined by SDG&E/SoCalGas' Gas Control Department.

- Capacity Products Staff – Support the activities of the Pipeline Products and Storage Products groups.

Intervenors' misunderstanding of the structure and functioning of the System Operator has led them to confuse the issues and to overstate the potential for improper behavior. Indicated Producers (IP), for example, appears to incorrectly assume that the term "System Operator" refers to something other than the "Utility System Operator" approved in the Omnibus proceeding. It suggests that the "System Operator" is a new function being proposed within this application. As noted above, the terms "System Operator and "Utility System Operator" are synonymous. Based upon the flawed premise that the System Operator is structured as a discrete functional group within SoCalGas, rather than the distributed function described in the "Utility System Operator" definition, IP asserts that the "System Operator" could act improperly in calling such items as Operational Flow Orders (OFOs) or Minimum Flow Orders (MFOs) in order to enhance the profitability of the Operational Hub. This assertion ignores the fact that the Utilities' Gas Control Department, which is responsible for calling OFOs and MFOs, is structurally separate from the Operational Hub. As explained above, while both functions are included under the general "Utility System Operator" umbrella, they are in separate organizations within the utility structure. Detailed discussion of the Utilities' Gas Control Department's exclusive focus on reliable system operations, as distinct from the Operational Hub's focus on maintaining flowing gas supplies, is included later in my testimony and in the rebuttal testimony of Mr. Bisi.[2]

Similar confusion appears to exist in the testimony submitted by Laird Dyer on behalf of Shell Energy North America (US), L.P. (Shell). Mr. Dyer asserts that the "System Operator" should be separated from the Storage and Operational Hub commercial activities. It is not entirely clear what function Mr. Dyer has in mind when he refers to the "System Operator,"

[2] It is important to note that ensuring reliable system operations goes beyond what Shell described as simply maintaining pressure in the pipelines and focuses on the broader task of being able to provide reliable utility service to all end-use customers.

however, since that term is broadly defined to include several departments within SDG&E/SoCalGas that are integral to providing service to customers. Based on Mr. Dyer's testimony, it would appear that he intends to suggest that there should be separation between the system reliability function (*i.e.*, SDG&E/SoCalGas' Gas Control Department) and the Storage and Operational Hub commercial activities. As explained above, structural separation already exists between the SDG&E/SoCalGas' Gas Control Department and the Operational Hub. Thus, the separation Mr. Dyer proposes is currently in place.

A. Why a Southern System Minimum Flow Requirement is Necessary

The need for a minimum flowing supply requirement into the southern system is not a recent development. Historically, SDG&E/SoCalGas' Gas Procurement Department managed any supplies necessary to ensure minimum flow on the southern system, as determined by SDG&E/SoCalGas' Gas Control Department. Management of a Southern System minimum flow requirement request by SDG&E/SoCalGas' Gas Control Department to obtain additional supplies is now shifting to the Operational Hub (effective April 1, 2009).[3] It is important to note, however, that the determination of how much gas is needed to support the southern system continues to be the responsibility of SDG&E/SoCalGas' Gas Control Department. Thus, the suggestion by IP witness, Susan Schneider, that there is a change in the entity responsible for determining the flowing supply needs of the southern system is incorrect.

Why does SDG&E/SoCalGas have a minimum flow situation on its southern system? Two reasons: (1) the system was originally designed to redeliver gas supplies from the Permian and San Juan Basins, and (2) the development of new supply basins resulted in the creation of new receipt points on the SoCalGas/SDG&E system, providing customers with greater choice and flexibility in their gas supplies. As customer preference for gas supply shifted away from the Permian Basin due to price differentials, gas supplies delivered at the Blythe receipt point were reduced. This presented operational difficulty because service to a number of customers depends upon the physical delivery of supply into the southern system, historically at Blythe.

[3] SoCalGas AL 3818-A.

SDG&E/SoCalGas' tariffs provide customers with the flexibility to purchase gas supplies at any receipt point coming into the SDG&E/SoCalGas system, regardless of where their actual demand is on the system. Customers in the San Joaquin Valley, for example, may purchase gas supplies delivered at Otay Mesa in San Diego County. SDG&E/SoCalGas believe that this flexibility is attractive to customers. It does, however, give rise to the need to ensure that minimum flowing supply needs into the southern system are met.

In order to continue to provide such flexibility most operators would consider two primary options, build facilities based on customers desire to pay for those facilities to eliminate the problem or reduce customer flexibility. As cost estimates for facilities to eliminate the problem are high, SDG&E/SoCalGas do not believe customers are willing to pay for those facilities. SDG&E/SoCalGas have identified the facility alternative to the Southern System minimum flow requirement to be the construction of a new pipeline linking the North Desert transmission system and the Southern System. This pipeline, consisting of approximately 100 miles of 36-inch diameter pipeline, is estimated to cost in excess of $300 million.[4] SDG&E/SoCalGas project the first year cost of this pipeline to be $48 million and the 50-year levelized costs would be $33 million per year.

Therefore some reduction in customer flexibility would be the next logical choice for an operator. Rather than completely eliminating the receipt point flexibility currently afforded under their tariffs, SDG&E/SoCalGas have developed a method for responding to southern system minimum flow requirements that reduces customer flexibility in a limited manner only on those days when the system experiences a problem. The proposed Southern System Flow Order (SSFO) operates on a temporary basis and minimally impacts the high degree of flexibility granted to customers. Given that the overall national gas market is regulated by FERC, with state commissions regulating local distribution companies (LDCs), and is generally based on customer choice, SDG&E/SoCalGas do not have the ability to turn gas supplies on and off, like the ISO may elect to do with power plants. Therefore, by calling a SSFO, customer flexibility is

[4] A.08-02-001, SoCalGas Responses to Second Set of Data Requests of Indicated Producers, Q 9.5 (Attachment A).

temporarily and partially reduced and the customers are able to turn on and off the supplies at the required points.

First and foremost, SDG&E/SoCalGas are concerned about reliable system operations, which not only include the safety parameters such as MinOP (Minimum Operating Pressure) and MAOP (Maximum allowable operating pressure), but also include continuing to provide service to customers. The southern system minimum flow requirement is essential to avoiding curtailments on the southern system. Under current tariff rules, SDG&E/SoCalGas may discontinue service if there are insufficient gas supplies on the southern system, to restrict or curtail load if necessary.[5] The rationale for SDG&E/SoCalGas obtaining gas supplies to meet a flowing supply requirement on the southern system is to avoid curtailing customers at a lesser cost than other alternatives. Had SDG&E/SoCalGas not instituted a minimum flow requirement, curtailments would likely have occurred. The Commission would have been concerned and customers would have certainly complained. As a result of the curtailments, SDG&E/SoCalGas may have been required to propose pipeline facilities to be built in order to avoid the curtailments. This course of action would be the likely outcome for many pipeline or distribution companies.

Instead, SoCalGas instituted a practice of buying supplies to meet a defined minimum flowing supply requirement, when necessary, at Blythe in order to avoid customer curtailments. Customers have benefited greatly from this practice by avoiding curtailments and incurring lower annual costs than if pipeline facilities had been built and put in service. Thus, SDG&E/SoCalGas have taken on responsibilities beyond those related to typical system operations.

D.07-12-019 approved SDG&E/SoCalGas' proposal to transfer the responsibility of purchasing flowing supplies to maintain system reliability to the Utility System Operator and placed the financial burden of acquiring such minimum flowing supplies on all customers rather than primarily on core customers. SDG&E/SoCalGas' proposal identified the Operational Hub as the organization group that would be physically buying the supplies. The Operational Hub

[5] SoCalGas Rule 23 and SDG&E Rule 14.

will <u>not</u>, as previously noted, be involved in determining if and how much additional supplies are needed on a given day. Rather, that determination will be made by SDG&E/SoCalGas' Gas Control Department, which is responsible for the 24/7 operation of SDG&E/SoCalGas' pipeline system. SDG&E/SoCalGas' Gas Control Department will provide direction to the Operational Hub concerning when additional supplies are needed and the quantity of supplies needed on a given day. This procedure is essentially identical to that in place today. Under the current procedure, SDG&E/SoCalGas' Gas Control Department provides direction to SDG&E/SoCalGas' Gas Procurement Department to acquire the supplies. Going forward, the Gas Control Department will provide direction in exactly the same way to the Operational Hub. The Operational Hub will also manage the Request for Offers (RFO) process adopted in D.07-12-019[6] to develop contracts with outside parties, file the Expedited Advice Letter for approval of those contracts, and manage implementation of the approved contracts as the need is determined by SDG&E/SoCalGas' Gas Control Department.

SCGC witness Yap claims without support that SDG&E/SoCalGas' efforts to issue the RFO and obtain contracts to meet the southern system minimum have been "half-hearted" and suggests that a data request by SCGC was necessary to spur SDG&E/SoCalGas to issue the RFO. SCGC's claim is nonsensical; the timing of issuance of the RFO was based upon the effective date of the transfer of the supply management responsibility to the Operational Hub. As the Commission recognized in approving SoCalGas' Advice Letter 3818-A, the transfer of the requirement for purchasing of flowing supplies would not occur until 4/1/09. The RFO was scheduled to occur within four months of the effective date of the transfer so that that the contracts could go into effect on 4/1/09. SCGC's suggestion that the RFO should have been issued over one year prior to transfer of supply management responsibility is illogical and impractical. Issuance of the RFO in December, 2008 reflected SDG&E/SoCalGas' intent to develop a prudent timeline and to avoid requiring parties to provide offers of service far in advance of the effective date. The timing of the RFO was driven by this concern, rather than by the timing of the BCAP application or any particular data request.

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6 D.07-12-019, OP 16.

B. Comparing SDG&E/SoCalGas' Operation of Their Pipeline System to the Functions of the ISO is Inappropriate

In her testimony on behalf of IP, Susan Schneider draws an ultimately unsuccessful comparison between the SDG&E/SoCalGas Utility System Operator and an electric Independent System Operator (ISO). The intent of the comparison is to highlight perceived deficiencies in regulatory oversight of the Utility System Operator when compared with regulatory oversight of an ISO. The comparison quickly falls apart, however, once the roles of each entity are fully understood. While both entities are tasked with the basic function of maintaining system reliability, the ISO's responsibilities far exceed those of the Utility System Operator in terms of both breadth and complexity, and justify the additional safeguards and transparency mechanisms to which the ISO is subject.

In the context of system reliability, and only in this context, the comparison between the Utility System Operator and the ISO is apt and reinforces the appropriateness of the tools for ensuring system reliability proposed by SDG&E/SoCalGas. The ISO deals with inadequate generation in local areas through the use of Reliability Must Run (RMR) contracts – *i.e.*, contracts that require a unit to run when generation is required to ensure system reliability. RMR contracts provide a dual purpose: they ensure that a unit is available to provide electrical support when needed and they protect ratepayers against monopoly pricing. In addition, in order to manage congestion on the grid, the ISO can instruct specific generators to either increase or decrease their output to relieve the constraint. The ISO can also make out-of-market and out-of-sequence (economic dispatch) purchases to maintain system reliability. All of these actions can have an impact on the market clearing price.

Similar to the ISO's RMR contracting authority, the Utility System Operator has the ability to contract with suppliers to provide additional flowing supply, when needed. The approved RFO process currently underway may result in contracts for such services being approved by the Commission. While the ISO is afforded a great deal of control over generators' output in order to control flow over the grid, SDG&E/SoCalGas seek only a limited ability to direct customers' deliveries of gas in order to ensure the reliability of the southern system. As explained above, SDG&E/SoCalGas generally allow suppliers a high degree of flexibility in delivering gas at any delivery point they choose. It is this flexibility that creates the need for the Southern System Flow Order (SSFO). If flows on the southern system are inadequate because suppliers prefer alternate deliver points, the Utility System Operator, as an alternative to installing physical facilities, must obtain additional flows on the system at particular receipt points.

Under the proposed SSFO mechanism, suppliers would be required on a temporary basis to deliver no more than 20% of their expected demand into the southern system. This requirement could obviate the need for the Utility System Operator to enter the spot market and impact market prices. Thus, the Utility System Operator's call for an SSFO is less intrusive than the ISO's direct intervention in the market to maintain system reliability. This restrained approach is by design; if SDG&E/SoCalGas were to take an approach similar to that taken by the ISO, access to the system at receipt points on the northern part of the system would be limited in order to force customers to obtain supplies on the southern system. This would directly impact California suppliers such as Occidental and Chevron. Instead, the proposed SSFO works in a more customer-friendly manner and does not involve ISO-like restrictions on access.

Beyond the basic responsibility to ensure system reliability, there is little functional similarity between the Utility System Operator and the ISO. The Utility System Operator is not a specific, discrete organization like an ISO. The Utility System Operator refers to functions that SDG&E/SoCalGas have performed since its inception to ensure gas system reliability. These functions, procedures, and operations have evolved over time, are well-documented, and are fully understood and supported by the Commission. Measurement of end-results (*e.g.* curtailments, safety-related events, harm to pipeline facilities, environmental incidents, etc.) and Commission oversight ensures that system reliability criteria are met. Micro-management of the Utility System Operator by requiring detailed immediate postings and additional stakeholder consultation would not be constructive in light of the existing Commission regulations designed to ensure system operations and reliability. The ISO, on the other hand, is required to perform many more major tasks than the SDG&E/SoCalGas' Gas Control Department. As a result, the more stringent regulatory oversight, individual safeguards, and transparency mechanisms applicable to the ISO are justified.

The role and responsibilities of an ISO are markedly different from those of the Utility System Operator. Rather than being responsible solely for the relatively straightforward task of ensuring system reliability, the ISO is designed to achieve certain additional market design and operational objectives. These include (i) delegating operational control of an electric transmission system to an entity other than its owners; (ii) preserving the regional nature of the electric grid, and (iii) the creation, monitoring, and operation of markets for electricity, as discussed below. These functions, by their very nature and complexity, require a significant amount of oversight and transparency. The Utility System Operator performs none of these functions with respect to the gas market. Thus, the unique and additional functions of the ISO, and not necessarily the differences in the complexity between gas and electric transmission systems, necessitate a much greater degree of oversight, as well as detailed operational instructions.

With respect to the first of the objectives noted above, the need for the ISO is premised on the notion that in order to effectively increase competition in the electric industry, it is necessary to break the link between the ownership of generation and the operation of the transmission grid by individual utilities. The purpose of the ISO is, at least in part, to prevent discriminatory use of the transmission system to benefit generation owned by the transmission owner. By contrast, the gas transmission system has been an open access system for more than 20 years and has functioned well without divestiture of the transmission assets of the local distribution companies. Unlike with electric generation, local gas distribution companies do not own the gas production facilities that seek access to the utility system.

Regarding the second, creation of an ISO recognizes and preserves the regional nature of electric transmission. The ISO oversees a FERC regulate electric transmission system that is comprised of facilities owned by more than a single utility. The interconnection of separately owned transmission lines forms an electric grid that crosses state boundaries. Hence, the electric grid results in interstate commerce, which requires FERC regulation of the electric transmission grid. The regional nature of the transmission grid further highlights the additional complexity of transmission planning. Because the benefits and assigned costs of transmission expansions are not easily calculated, the FERC has required that ISOs conduct a very detailed transmission planning process.

IP suggest that SDG&E/SoCalGas have inferior system planning, as compared to the ISO, and no public transmission-planning process.[7] This assertion ignores the obvious fact that gas transmission system planning differs greatly from electric transmission planning. Gas transmission planning is utility-specific and does not involve network externalities to the same extent as electric transmission. This makes it much easier to discern the costs and benefits related to a new gas transmission expansion. As a result, the gas industry conducts open seasons to test the economic viability and need for expansions. Customers compare the cost of new facilities to changes in operations, conservation, and other alternatives. In this sense, gas transmission planning is much more efficient than electric transmission planning because it receives direct input and solicits commitments from its customers.

Finally, in the context of market development, the goals of the ISO and the Utility System Operator diverge significantly. There is a fundamental difference between the role of an ISO as the entity responsible for creating, operating, and monitoring various markets for electricity and the function performed by SDG&E/SoCalGas' Gas Control Department as a market participant for a limited purpose. The ISO's mission is a major undertaking requiring stringent oversight and detailed market rules and regulations, as well as intense stakeholder participation.

Plainly, given the considerable differences in the responsibilities and functions served by the ISO versus those of the Utility System Operator, the attempt by Ms. Schneider to compare the two entities is frivolous. A more relevant comparison would be to gas interstate pipeline requirements imposed by FERC. While ISOs and interstate pipelines are both regulated by FERC, FERC has not sought to impose upon interstate pipelines regulations similar to those imposed on ISOs. FERC has not imposed on interstate pipelines requirements such as posting of

[7] Direct Testimony of Susan R. Schneider on behalf of the Indicated Producers, pg. 12.

individual Hub transactions, detailed operating procedures, required stakeholder forums, independent and outside review of proposals prior to filing, or a public transmission planning process. FERC does have affiliate transaction rules, and monitors compliance to those rules. Those requirements are consistent with those imposed by the Commission. While neither FERC, nor the Commission, have perceived a need to impose ISO-type regulations outside of the ISO context, this is precisely what IP suggests the Commission do. IP fails, however, to provide a persuasive rationale for doing so. As Ms. Schneider acknowledges, the Commission has approved the structure of the Utility System Operator, including the Operational Hub as the entity to purchase physical supplies under the direction of SDG&E/SoCalGas' Gas Control. Any potential conflicts of interest are addressed through the departmental separation between Gas Control and the Operational Hub, along with the Commission oversight of the activities of the Utility System Operator.

C. SSFO is an Appropriate Tool

Undoubtedly, the best operational method to address the southern system minimum flow requirement would be to build pipeline facilities to eliminate the southern system minimum altogether. Building new facilities would obviate the need for SDG&E/SoCalGas to buy operational supplies or to call SSFOs, and would preserve the receipt point delivery flexibility customers enjoy today. As a practical matter, however, installing facilities would involve significant costs and would take several years. Accordingly, since the southern system minimum problem has historically existed only on certain days, SDG&E/SoCalGas have attempted to identify a less costly, more nimble solution and have, through the Utility System Operator, taken on the responsibility of acquiring additional operational supplies for the sole benefit of the end-use customers. The next best alternative is to require customers to deliver gas into the southern system (*i.e.*, the SSFO mechanism). The remaining option is to curtail customers, which SoCalGas makes every possible effort to avoid due to the impact a curtailment of gas service would likely have on the electrical grid system and the financial impact to California as a whole.

From an operational standpoint, SDG&E/SoCalGas have no particular desire to be in the gas buying business. Nor do they wish to expand the current role of the Utility System Operator beyond that established in the Omnibus decision, contrary to the suggestion of IP witness Schneider.[8] To the extent certain parties harbor concern regarding the Utility System Operator's involvement in commodity market activities, the SSFO proposal would, in fact, offer a solution. The SSFO is a less market-intrusive approach than having the Utility System Operator in the gas marketplace, occasionally buying and selling supplies and, as such, should result in overall lower cost to the customers. In fact, all the reasons set forth by IP as to why the Utility System Operator should not be in the gas purchasing business provide support for the SSFO proposal.

Parties' concerns with the SSFO appear to focus mainly on the intermittent nature of the proposed requirement and the length of the notice period. These concerns, as articulated by the parties, include the following:

- Additional resource and administrative burdens on customers.
- Non-compliance penalties.
- Potential imbalance penalties under G-IMB.
- Penalties for breaching contractual obligations at other receipt points.
- Loss for distress sale of gas at other points to avoid the other costs.
- Additional FAR expense if they have already purchased rights at another receipt point.
- Short notice for calling SSFO causes difficulty and worsens the other potential problems.

Parties express the concern that, due to the timing of the calling of an SSFO, they will have various problems with existing arrangements made prior to the SSFO being called. They may be required to breach prior upstream contracts, sell supply already purchased, be out of balance because they did not plan for these volumes being delivered, and deal with the compounding effect of a short notice. SDG&E/SoCalGas understand these concerns; the Utility System Operator will face some of the exact same issues in buying supplies for the southern system. It should be noted that the concern regarding incurring additional access rights expenses

[8] Testimony of Susan R. Schneider on behalf of the Indicated Producers, pg. 24, line 34.

where FARs have been purchased at another point is unfounded. SDG&E/SoCalGas provide for use of these rights at other points without additional cost.

A potential solution to parties' concerns regarding the timing of calling SSFOs would be to place a standing SSFO for every day of the year or for defined months. This is similar to the winter balancing rules that define a customer's requirement to deliver a certain amount of its gas during defined winter periods. By having a standing SSFO every day, customers would be able to plan their purchases to avoid having to breach upstream contracts, would avoid potential imbalance penalties by planning to include southern system purchases against their demand, would not have to sell gas at other points since it would not have been purchased in the first place, and would not be subject to potentially short notices.

A daily SSFO is similar to the "exchange agreements" Shell proposes SDG&E/SoCalGas enter into, where customers commit to deliver gas for their own needs. SDG&E/SoCalGas did allow parties to propose exactly such exchange agreements in the RFO and such contracts may be entered into by SDG&E/SoCalGas to assist in meeting the southern system minimum.

SDG&E/SoCalGas have not proposed adoption of an everyday SSFO, despite the fact that an everyday SSFO would eliminate many of the concerns expressed by the intervenors regarding purchase of operational supplies by SDG&E/SoCalGas. SDG&E/SoCalGas believe that the more limited SSFO approach proposed makes sense. It is a better mechanism to support the southern system minimum than an everyday SSFO as it limits customer flexibility only on those days when the system is in need and not everyday. SDG&E/SoCalGas' proposed SSFO approach minimizes the inconvenience caused to customers and creates an appropriate balance between customers' desire for operational flexibility and SDG&E/SoCalGas' goal of ensuring a reliable system. SDG&E/SoCalGas would not, however, object to instituting a daily SSFO if the Commission concludes that such a mechanism is a better approach.

D. Potential OFO or other Operational Forums

IP witness Schneider and SCGC witness Yap suggest that SoCalGas/SDG&E be required to hold OFO or Operational Forums. IP and SCGC contend that an OFO forum is necessary in order to establish a set of objective standards for calling an OFO[9] and to potentially develop measures to reduce the number of OFO events.[10] In addition, both parties acknowledge that PG&E has already held similar OFO forums with respect to its gas system.[11]

SDG&E/SoCalGas are open to further exploring the possibility of an OFO or Operational Forum. In fact, SDG&E/SoCalGas previously supported the Comprehensive Settlement Agreement in D.01-12-018, which would have established such an OFO forum. However, the provisions of that decision, including those related to holding an OFO forum, were not implemented.[12] SDG&E/SoCalGas believe that an OFO forum, if properly structured, could reduce transparency concerns regarding system operations, provide customers with additional insight regarding the operational realities of SDG&E/SoCalGas' system and offer a potential venue for discussion of additional tools to be used to support system operations prior to regulatory filings. Before taking any action to establish an OFO forum, however, it is important that the Commission make clear that SDG&E/SoCalGas retain the full and sole responsibility to operate their gas system.

IP witness Schneider and SCGC witness Yap seem to imply a failure on the part of SDG&E/SoCalGas to apply objective standards in calling an OFO event. This suggestion is incorrect. SDG&E/SoCalGas take their responsibility to provide reliable service to customers very seriously and manage their system to that standard, while continuing to provide customers as much flexibility as possible. Based on the current formula, if gas is scheduled to enter the system in excess of the system's capacity to accept the gas, an OFO must be called to preserve the integrity of the SDG&E/SoCalGas system and to ensure reliable service to customers. This evaluation occurs every day and the majority of the time there are no issues. When an issue does arise, however, an OFO event is triggered – this is true whether an event occurs 1 day a year or

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9 A.08-02-001, Direct Testimony of Catherine E. Yap on Behalf of Southern California Generation Coalition, page 46.

10 A.08-02-001, Direct Testimony of Susan R, Schneider on behalf of the Indicated Producers, pg. 7.

11 SoCalGas/SDG&E would simply note that it is interesting that IP and SCGC seem to be so enamored with the idea of implementing OFO forums for the SoCalGas/SDG&E system that have occurred just twice in a decade on the PG&E system.

12 D.01-12-018, FOF 22.

365 days. This issue is discussed in more detail in the rebuttal testimony of SDG&E/SoCalGas witness, Mr. Bisi.

SDG&E/SoCalGas remain open to the idea of OFO forums, if they can be managed in a productive way and in no way limit SDG&E/SoCalGas' sole responsibility for management of their pipeline system. In addition, the OFO forums held on the gas side must be more limited in scope than those held by the ISO. Despite IP's attempt to compare the two, it would not be appropriate or a reasonable use of resources for SDG&E/SoCalGas to undertake a wide-ranging examination of a vast number of market issues in the manner of the ISO. SDG&E/SoCalGas also have concerns with the OFO forum discussing measures or tools to meet the southern system minimum requirements inasmuch as many of those parties participating in the OFO forum may also be market participants likely to provide gas supplies to SDG&E/SoCalGas in order to meet the minimum flow requirement.

E. Additional Market Transparency and Posting Requirements Would be Detrimental to Customer Costs and Would Potentially Reduce Customer Use

IP witness Schneider implies through a series of unsubstantiated claims and irrelevant examples that the SDG&E/SoCalGas will manipulate informational input, modify operations or take direct actions not supported by the need for reliable system operations in support of shareholder gain.[13] She suggests that SDG&E/SoCalGas will act improperly to enhance profits for Sempra affiliates and the SDG&E/SoCalGas' Gas Procurement Department, and ignores the fact that rules are in place under both state and federal regulatory authority to prevent such activity. SDG&E/SoCalGas take affiliate and associated rules seriously and are troubled that IP would make unsubstantiated claims suggesting the contrary. IP asserts that the Commission should be concerned about potential conflicts of interest between SDG&E/SoCalGas and other Sempra Energy entities[14] and offers a number of hypothetical situations in which such transactions between Sempra companies could benefit shareholders at the expense of

[13] Direct Testimony of Susan R. Schneider on behalf of the Indicated Producers, page 14 – 16, starting at line 34.

[14] A.08-02-001, Direct Testimony of Susan R. Schneider, on behalf of the Indicated Producers, page 14.

ratepayers.[15] IP fails to point out, however, that not one of these situations has actually occurred, and appears unaware of the fact that Affiliate Compliance Rules would prevent these types of hypothetical scenarios from taking place.

IP's claims are offered in order to support its proposals designed to increase the transparency of Utility System Operator operations, which it contends will safeguard against the purported adverse impacts of the Utility System Operator.[16] Specifically, IP proposes to require the Utility System Operator to post the transaction price, counterparty, volumes, dates, delivery/receipt points, and special terms for all gas transactions related to the southern system minimum, as well as additional daily posting requirements for Operational Hub services contracts. While such information would, no doubt, be of interest to market participants, including the members of IP, SDG&E/SoCalGas believe such posting requirements would be imprudent and would ultimately harm utility customers. Disclosure of the market-sensitive information related to purchases made in order to meet the minimum flowing supply needs of the southern system would provide insight into the Utility System Operator's procurement patterns and would allow market participants to gain knowledge in order to predict future purchases by the Utility System Operator. The ability to precast the needs of the Utility System Operator would permit market participants to extract higher prices to the detriment of end-use customers.

While simple logic dictates this outcome and the harm to end-use customers that would result, IP fails to demonstrate that any harm would result from not posting these irregular purchases.[17] IP's concerns regarding potential conflict of interest in the Utility System Operator's contracting with affiliates are unfounded. The Commission has addressed the affiliate issue with respect to purchases between the SDG&E/SoCalGas' Gas Procurement Department and an affiliate. The Commission has previously decided that transactions can take place between SDG&E/SoCalGas and an affiliate, if they are transacted through an independent medium, such as ICE or a broker where the counterparties are not known until after the deal is completed. The Utility System Operator has proposed the same method for its purchases with

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[16] Direct Testimony of Susan R. Schneider on behalf of the Indicated Producers, page 18.
[17] Direct Testimony of Susan R. Schneider on behalf of the Indicated Producers, page 7.

affiliates and most likely with SDG&E/SoCalGas' Gas Procurement Department. Utility System Operator purchases with SDG&E/SoCalGas' Gas Procurement Department cannot be completely restricted through those mediums as supplier of last resort requests can not be made in this manner.

IP also proposes that SDG&E/SoCalGas be required to post each individual Operational Hub transaction immediately after execution. This requirement would provide customer-specific information to the marketplace and could potentially put the customer at risk for increased costs. For example, assume that SDG&E/SoCalGas were required to post individual Operational Hub transactions. Under this scenario, SDG&E/SoCalGas would have to post all loan and park transactions with parties, making it fairly easy for market participants to deduce that Party A with a loan payback due in July would likely need to buy additional supplies in July. This information could be used by a market participant to extract a higher price from Party A for the necessary supplies. These types of burdensome posting requirements are unfair to customers and could ultimately lead to a reduction in customer use of Operational Hub transactions and/or a lack of customer confidence in dealing with SDG&E/SoCalGas.[18] SDG&E/SoCalGas already post the net monthly Hub position on a weekly basis on the EBB system, which is more than adequate to provide market transparency. The Commission should reject IP's proposal for additional posting requirements of Operational Hub service transactions and affirm that the net positions are in fact the critical elements needed to ensure the safe and reliable operation of the system.

Lastly, IP witness Schneider attempts to draw a comparison between the ISO's required information postings and those it recommends be adopted for the Utility System Operator.[19] Ms. Schneider claims that ISOs provide "extensive market and operating data" through OASIS postings. She fails to point out, however, that except for backup capacity procurement, the posted ISO data on OASIS is aggregated, not customer specific. To the extent the Utility System Operator has entered into contracts through the RFO process to increase gas flow to the southern

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[18] The Commission does not require PG&E or other storage providers to post specific Hub transactions on it system nor are interstate pipelines required to post such information.

[19] Direct Testimony of Susan R. Schneider, on behalf of the Indicated Producers, page 10 – 11, beginning at line 39.

system (somewhat analogous to ISO capacity procurement), these contracts will be presented through the Advice Letter process. The Utility System Operator entrance into the market is fully documented. It is impractical and counterproductive to the operation of competitive markets to disclose data regarding individual market transactions. The ISO is not required to provide proprietary, individual company data. In fact, the ISO goes to great lengths to assure market participants that proprietary market data are not released.

Ms. Schneider identifies five measures that she claims will increase transparency,[20] several of which are already completed or have been outlined by SDG&E/SoCalGas. First, she suggests that SDG&E/SoCalGas clarify that the mission of the Utility System Operator is to maintain system reliability at least cost and with minimal impact on competition. It is clear from SDG&E/SoCalGas' discussion of the Utility System Operator that this is the goal. Moreover, it is the mission of regulated utilities, like SDG&E/SoCalGas, to provide reliable service to customers at the lowest possible costs.

Second, Ms. Schneider suggests posting of five specific operating procedures. In response, SDG&E/SoCalGas notes the following with respect to each listed item:

1. Procedures are already posted for calling OFOs.
2. A proposed specific formula has been made in this application to determine the quantity of additional supplies needed on a given day.
3. The proposed SSFO procedure is for the Utility System Operator to exercise all prior approved contracts available and then call an SSFO to obtain the remaining southern system need, any called SSFO applies to all customers equally.
4. SDG&E/SoCalGas have already issued an RFO.
5. Use of additional tools will be provided when such tools are needed and asked for, to state them now would not make sense.

The remaining three measures proposed by Ms. Schneider are addressed in other sections of this testimony.

[20] Direct Testimony of Susan R. Schneider, on behalf of the Indicated Producers, page 18.

In conclusion, the additional posting requirements proposed by IP are unnecessary, would place additional burden on SDG&E/SoCalGas, are unfair to other end-use customers and would serve only to provide free market intelligence to market participants at the expense of end-use customers. Accordingly, the posting proposals offered by Ms. Schneider should be rejected the Commission.

F. Reasonableness Review of SRMA

D.07-12-019 adopted the Omnibus Applicants' proposal that the net cost of acquiring the supplies associated with meeting minimum flowing supply requirements be tracked in the System Reliability Memorandum Account (SRMA) and that all of this cost be equitably borne by all customers of SDG&E/SoCalGas system. D.07-12-019 requires SDG&E/SoCalGas to submit to a reasonableness review of this account before passing those costs on to ratepayers. SDG&E/SoCalGas strongly oppose hindsight reasonableness reviews of required supply purchases for minimum flow requirements, as well as the inability to pass those costs on to customers until a specific review is completed. Purchases of supply to meet minimum flow requirements are intended to benefit customers by providing reliable service and avoiding curtailments. SDG&E/SoCalGas view the use of a specific reasonableness review as a step backward in the Commission's regulatory process as it is contrary to well-defined incentive mechanisms the Commission has rightfully supported for more than a decade. In fact, the Commission moved in the direction of incentive mechanisms precisely because of the difficulty of hindsight reasonableness reviews for all parties, including the Commission.

SDG&E/SoCalGas strongly recommend that this aspect of D.07-12-019 be eliminated, and if not eliminated, at least modified. SDG&E/SoCalGas should be permitted to pass costs booked into the SRMA onto customers in the regular annual update of the balances in the approved regulatory accounts. Many of the costs will be those associated with already-approved tools, such as the cost of gas purchased under the Commission-approved contracts resulting from the Request for Offers (RFO) process adopted in D.07-12-019. Pursuant to this RFO process, contracts will be processed through an expedited Advice Letter filing. Once approved by the Commission, the costs associated with such contracts should not be reexamined in a reasonableness review. For example, if a contract including a demand or reservation charge that must be paid regardless of actual use is submitted via Advice Letter and approved by the Commission, that cost should be deemed reasonable and SDG&E/SoCalGas should be allowed to pass on such cost each year. Similarly, if an approved contract includes a set price for gas supply and if that contract is utilized during a period based upon a need determined by SDG&E/SoCalGas' Gas Control Department, those costs should be deemed reasonable and should not be subject to a second review prior to being passed on to customers. In short, where the terms of a contract, including price, have been approved by the Commission, conducting a second review of the already-approved charges contained in the contract would be redundant, counter-productive and overly burdensome. Moreover, precluding these costs from being passed on to customers each year would require SDG&E/SoCalGas to carry the costs. The Advice Letter process should approve the tool proposed and the potential costs of those tools should at the same time be deemed reasonable. Tools already approved through an advice letter have already passed a reasonableness test and should not be subject again to an additional after-the-fact review.

The Commission will have the opportunity to review the costs booked into the account for reasonableness in conjunction with the annual update of the regulatory account balances, and SDG&E/SoCalGas recommend that the activities and account should not be subject to a reasonableness review. If the Commission is concerned about the level of costs being incurred by SDG&E/SoCalGas in order to meet the minimum flow requirements, it can always address that matter in the next BCAP/TCAP on a prospective basis without prejudging required actions on the part of SDG&E/SoCalGas to maintain safe and reliable service.

In discussing this issue, IP fails to distinguish between a regulatory account review and a review of system operations. It appears that IP seeks the ability, during a reasonableness review of the costs booked into the account, to second-guess the real-time operational decisions made in establishing a southern system minimum. Clearly, this should not be the intent of the Commission with respect to the reasonableness review of the SRMA.

G. SDG&E/SoCalGas Currently Have Sufficient Operational Procedures in Place

IP challenges the adequacy of SDG&E/SoCalGas' current operational procedures. It ignores the existence of provisions of the Public Utilities Code and Commission rules that define the obligations of SDG&E/SoCalGas as regulated local distribution companies. The Commission has oversight of these and other rules (such as the remedial measures and affiliate compliance) regarding SDG&E/SoCalGas' operation, as described in more detail in the testimony of SDG&E/SoCalGas witness, David Bisi. IP appears to suggest that the Commission is deficient in its administration and oversight of SDG&E/SoCalGas' operations as well as in its enforcement of compliance with filed tariffs and underlying Commission rules. Commission oversight and review of adherence to adopted rules has operated properly for many years and no change is necessary now. The operation of the system has not changed; the only aspect that has changed is the identity of the party purchasing supplies when the SDG&E/SoCalGas' Gas Control Department defines a need for additional supply on the southern system. IP witness Schneider asserts repeatedly, and incorrectly, that SDG&E/SoCalGas are proposing a new operation. This is patently false, as the structure of the Utility System Operator, and its activities, were established in the Omnibus decision, D.07-12-019.

IP also asserts that current procedures do not permit effective evaluation of whether SDG&E/SoCalGas are operating appropriately. Historically, the Commission has managed such oversight primarily through performance reviews. If the Commission is not satisfied with performance, a full audit may be conducted and SDG&E/SoCalGas could face penalties for not operating properly as a regulated local distribution company under Commission jurisdiction. IP's claims that this degree and method of oversight is not sufficient are unfounded; IP's proposal for detailed procedures is not necessary.

Moreover, many of the non-system operation procedures proposed by IP have already been defined by SDG&E/SoCalGas. IP appears to ignore SDG&E/SoCalGas' proposed formula for determining the need for additional supplies on the southern system, which is intended to establish a formula that would permit a more objective analysis of the need to purchase supplies.

IP instead calls for more general procedures, without stating what specific procedures they would like to see, or suggesting any specific procedure examples.

The only non-operational procedure that IP clearly addresses is the manner in which the Utility System Operator Tools will be used.[21] This procedure, as SDG&E/SoCalGas have stated previously, is relatively simple: tools will be used on a least-cost basis. Once SDG&E/SoCalGas' Gas Control Department determines that a quantity of gas must be obtained, SDG&E/SoCalGas' Operational Hub will exercise approved contracts on a least-cost basis. Least cost will be determined based upon the marginal cost to obtain the volumes.[22] The details of the potential contracts (fixed charges, variable charges, exercise timing, etc.), and where they fit in the cost order, will all be part of the Advice Letter filing requesting approval of these contracts.

H. The Advice Letter Process is the Appropriate Vehicle to Seek Approval of Additional Minimum Flow Supply Requirement Tools

As I explain in my direct testimony, D.07-12-019 established certain tools to be used by the Utility System Operator to support the southern system minimum flow requirement, including purchases of spot gas supplies and running an RFO prior to taking on the responsibility of purchasing gas for the system reliability requirement. D.07-12-019 also provided for approval of additional tools to meet minimum flowing supply requirement, with approval to be sought through the standard advice letter process on an interim basis and review of that process in SDG&E/SoCalGas' next BCAP. SDG&E/SoCalGas propose to maintain the advice letter process for approval of additional tools to maintain system reliability by purchasing flowing supplies or, alternatively, to use an application such as the BCAP/TCAP filing.

The standard advice letter process allows for review, discovery of pertinent information and if the advice letter is disputed, issuance of a Commission resolution. SDG&E/SoCalGas could be ordered in a resolution to file an application if the issues included in the advice letter are

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[21] Direct Testimony of Susan R. Schneider on behalf of the Indicated Producers, page 14, lines 8-21

[22] Some contracts may not be exercisable. For example, a contract could require that it must be exercised a certain number of hours before nominations, that time may have passed when SDG&E/SoCalGas' Gas Control Department makes the request. Or if in the unlikely event a contract calls on the purchase of an index plus $.50 per Dth and supplies are available in the spot market at less, then it would make sense for the Operational Hub to not exercise the contract.

too complex or if disputes cannot be resolved through a Commission resolution. Imposition of an across-the-board application filing requirement constitutes regulatory overkill. Adjudicating an application takes 6 months to one year, at minimum, which simply is not practical for many of the "tools" that could require Commission approval. SDG&E/SoCalGas agree that a new "tool" like the proposed SSFO or a proposal to build facilities (even though facility additions could likely require a separate application) require more than an advice letter. Likewise, if SDG&E/SoCalGas negotiate a new contract for an optional supply source in support of the southern system minimum, obtaining approval through an advice letter should be more than sufficient. If an application is required, it is quite possible that the length of time it would take to approve the contract through an application process would exceed the term of the contract being presented. That would have the effect of limiting SDG&E/SoCalGas' ability to effectively meet the minimum requirement through additional contracts. Parties remain free to assert a need, where appropriate, for approval via the application process, but SDG&E/SoCalGas should not be required to use the application process as its first course of action.

II. Utility's Proposed Noncore Transmission Customer Rate Design

IP/CCC/CMTA/Watson "strongly support" the general structure for the TLS rate design. TURN prefers the current peaking rate, but failing the retention of that mechanism to prevent uneconomic partial bypass of the utility, is willing to support SDG&E/SoCalGas' proposal. Only three parties, SCE, SCGC, and Long Beach, have submitted testimony asking the Commission to reject SDG&E/SoCalGas' TLS rate design. These parties' positions on the TLS rate (SCE, SCGC, and Long Beach) can be easily summarized: they prefer the status quo - a class average, all-volumetric rate structure in lieu of the TLS rate. In addition, SCE proposed a modified Peaking Service rate and SCGC proposed a modified TLS design. Their proposals should be rejected inasmuch as they (1) conflict with the Commission's direction to close or sufficiently narrow the "regulatory gap" between SoCalGas' rates and services and those of competing interstate pipelines to allow SoCalGas to eliminate the Peaking Service tariff (Schedule GT-PS), and (2) encourage uneconomic partial-bypass and cause the remaining captive customers' rates to rise.

A. The TLS Rate Design Complies with the Commission Order

Some opponents to the TLS proposal ignore the fact that SoCalGas was ordered by the Commission to redesign its rates for the purpose of closing or minimizing the "regulatory gap" created by the use of a volumetric rate design on SoCalGas' system and the interstate pipelines' use of rate design that recovers the fixed costs of the pipeline in a fixed charge and the variable costs through a volumetric charge. (D.06-12-031, p.128) None of the opponents propose in their testimony a noncore rate design that would close the "regulatory gap," as SDG&E/SoCalGas was directed to do. The TLS rate, on the other hand, does just what the Commission ordered. The TLS rate is designed to mimic the interstate pipeline's rate structure, with a lower fixed demand charge rate to recover fixed costs of capacity available for those customers with a resulting rate that is comparable to, and in most cases competitive with, an interstate pipeline's rate. The TLS rate will send proper price signals to customers who are contemplating bypass of SDG&E/SoCalGas' system and will discourage uneconomic partial-bypass and cost shifting from partial-bypass customers to other customers of SDG&E/SoCalGas. Opponents of the TLS rate argue that EGs and lower load factor customers will be negatively impacted by the TLS rate. They ignore, however, the question of whether the TLS rate could be effective in sending proper price signals, thereby accomplishing the Commission's objective. SCE complains that there is significant difference between the load factor of electric generation customers and those of other noncore customers, and therefore that the EGs will be adversely impacted. SCGC argues that the TLS rate unfairly increases costs to low load factor customers and that low load factor EG customers have a lower cost of service on the utility system. SCGC also challenges the methodology and transmission system capacity used by SDG&E/SoCalGas to calculate the TLS rate. Long Beach argues that the TLS rate will increase its costs to its core customers due to the unpredictability of Long Beach's core load. Each of these arguments is addressed below.

B. The Effective Rate May be Differentiated by Customer Load Factor as a Result of the TLS Rate - as Intended by the Commission

SCE witness, Dr. Alexander, argues that EG customers pay more under the TLS rate than non-EG customers because, in general, the EG's load factor is significantly lower than non-EG customers. Dr. Alexander concludes in his testimony that "[t]he difference between the load factor of electric generation customers and those of other noncore customers is significant" (p. 17) based upon the suggestion that the class average load factor will be representative of each individual customer. In reality, there are low load factor customers in the EG group as well as in the non-EG group. Table 1 below shows the frequency distribution of the load factor as defined by Dr. Alexander for both the EG and non-EG groups. As the data shows, 35% of customers in the EG group will have load factor below 40%, versus 29% of customers in the non-EG group. The data also shows that a significant percentage of customers, both EG and other, have relatively high load factors of greater than 60%.[23]

Table 1 – Frequency Distribution of Load Factor for Transmission-level Customers

	Number of Customers		Percent	
	EG-TTier2	Other	EG-T Tier2	Other
LF <=40%	12	22	35%	29%
40% < LF <=60%	9	12	26%	16%
60% < LF <=80%	5	20	15%	27%
80% < LF <=90%	2	14	6%	19%
LF >90%	6	7	18%	9%
	34	75	100%	100%

Dr. Alexander calculates that the costs under the TLS rate for a 47% load factor customer will be 19% higher than the 90% load factor customer (Attachment MSA-4). This result is not surprising because that is exactly how SDG&E/SoCalGas predicted the TLS rate structure would function. Under the TLS rate structure, a high load factor customer has the opportunity to pay

[23] The load factors calculated in this section are based on monthly throughput numbers. Typically, load factors are based on peak day throughput. As a result, the calculated load factors are higher than the load factors based on peak day throughput.

less than a low load factor customer. As Commission pointed out in D.95-07-046 (page 6), a class-average, all-volumetric rate design inevitably produces cross-subsidy of low load factor customers by high load factor customers. The TLS rate is designed to reduce that cross-subsidy, because that is consistent with sending appropriate price signals to discourage uneconomic bypass to interstate pipelines. Removal or reduction of the cross-subsidy which has been enjoyed by the low load factor customers under the current all-volumetric rate structure will ensure that high load factor customers see a price that is more consistent with the price they would see when considering bypass of SDG&E/SoCalGas to an interstate pipeline. As described in my direct testimony, it is important to note that the typical interstate pipeline rate structure is a Straight Fixed Variable (SFV) rate design, where a customer signs up for the firm capacity it needs and pays for that capacity regardless of whether the customer uses it. Under an SFV rate design, as offered by interstate pipelines, a high load factor customer would on a volumetric equivalent basis pay less for service than a comparable low load factor customer. The TLS rate design produces an outcome consistent with this typical interstate pipeline scenario, and sends the proper price signals to those higher load factor customers, who are most at risk to bypass to an interstate pipeline offering SFV rates.

C. TLS Rate Does Not Unfairly Increase Costs to Low Load Factor Customers

SCGC witness Yap argues that TLS rate unfairly shifts costs to low load factor customers, predominately EGs that impose a low cost on the SDG&E/SoCalGas system due to the countercyclical nature of their demand. Ms. Yap erroneously asserts that low load factor customers are less expensive to serve than high load factor customers. On page 29 of her direct testimony, Ms. Yap states, “As can be seen from Chart1 . . . [t]heir concentration in the lower left corner demonstrates that on the SoCalGas/SDG&E system lower load factors tend to coincide with lower cost causation.” The evidence presented by Ms. Yap to support her claim is lacking and her conclusion is flawed.

Other than presenting two charts, SCGC provides no statistical evidence to support this assertion. The generally accepted method for determining whether there exists any association between the load factor and unit cost is to calculate the correlation coefficient (otherwise known as "R") between these two variables. Using the Chart 1 and Chart 2 data provided by Ms. Yap in SCGC's response to SDG&E/SoCalGas' Data Request No. 2, SDG&E/SoCalGas has calculated the R. The R for the data shown in Chart 1 and Chart 2 are 0.367 and 0.570, respectively. Statistically, these low R values indicate a weak relationship, if any, between the load factor and the unit cost for both Chart 1 (All Customers) and Chart 2 (EGs).

D. Low Load Factor Customers Are Not Less Expensive to Serve

SCGC witness Yap incorrectly asserts that because EG demand peaks in the summer, while other customer demand peaks in the winter, EGs cost less to serve because they help to improve SDG&E/SoCalGas' load factor. Applying this type of reasoning to claim that low load factor customers cost less to serve is overly-simplistic and erroneous.

At page 28 of her testimony, Ms. Yap wrongly claims that SDG&E/SoCalGas have not proven that a low load factor load is more expensive to serve than steady load. Simple math shows Ms. Yap's conclusion to be flawed. Start by assuming that all margin costs allocated to the TLS customers are fixed costs that can and should be recovered either through 365-day reservation charges or through an all-volumetric rate. By definition, the reservation charge should be lower than the volumetric rate because its denominator is a capacity-based denominator, whereas the volumetric rate uses annual average load. Whatever fixed costs are not recovered through the reservation charge commitments must then be recovered through the all-volumetric rate option. A customer with perfectly steady load for 365 days can make a reservation commitment for their entire load, and the average cost of serving that load is the reservation rate itself. A customer with very unsteady and volatile load will have to pay the higher volumetric rate on a pay-as-you go basis for some, if not most, of their load.

Although Ms. Yap's testimony suggests that EG load is countercyclical and does not contribute to the cost of the utility system as designed for a 1 in 10 peak day, in fact, the EG customer group does contribute to the winter peak day load. As shown in Table 2 below, during the past 8 years, the EG group has accounted for 42% to 66% of the noncore winter <u>peak day</u> demand. Clearly, when building the transmission system to meet noncore peak day load, the EG customer class must be, and is, fully considered.

Table 2

SoCalGas Historical Winter Peak Load

Peak Date	Core	Other Noncore	EG	System Total	Noncore Total (Other Noncore + EG)	% of EG to Noncore Total
Jan. 16, 2001	2260	1011	1939	5210	2950	66%
Jan. 30, 2002	2600	1069	1033	4702	2102	49%
Dec. 29, 2003	2147	951	691	3789	1642	42%
Nov. 30, 2004	2416	887	1067	4370	1954	55%
Jan. 4, 2005	2459	980	796	4235	1776	45%
Dec. 19, 2006	2386	929	846	4161	1775	48%
Jan. 15, 2007	2953	930	727	4610	1657	44%
Dec. 17, 2008	2559	884	1444	4887	2328	62%

In addition, Ms. Yap's assertion that "[t]he cost to serve low load factor EG customers tends to be lower than the cost to serve the high load factor EG customers because of the countercyclical nature of EG loads." (Yap, p. 30, line 17-18) is wholly inaccurate. SDG&E/SoCalGas witness, Mr. Bisi, states on page 6 of his direct testimony:

"Also note that an expansion in the Imperial Valley is currently underway to meet customer requested levels of firm transportation service in the summer operating season. This expansion is estimated at $40.7 million, and is expected to be in service by 2009. Unlike the SDG&E system or the San Joaquin Valley System, though, the Imperial Valley System is a summer-peaking system. Sufficient capacity exists on the Imperial Valley System even without the planned expansion to meet the 1-in-10 year cold day demand condition through the plan period."

As Mr. Bisi points out, SDG&E/SoCalGas will spend an additional $40.7 million on system expansions in order to serve the summer-peaking system in the Imperial Valley. These additional expansion costs prove that even low load factor, counter-cyclical EG loads can contribute additional costs to the system. Accordingly, Ms. Yap's argument that low load factor customers cost less to serve should be rejected.

E. TLS Will Not Unreasonably Raise Rates for Long Beach

Long Beach witness, William Monsen, complains that the TLS SFV-Volumetric rate is not suitable for Long Beach because Long Beach has difficulties in establishing an appropriate reservation amount for the SFV rate. Long Beach claims that because it must serve core demand

and must take the local natural gas supplies due to contractual agreement, it is challenging for it to forecast the gas demand and the reservation amount. Long Beach elaborates on the uncertainties of the demand forecast and the financial risks associated with the application of the TLS rate. SDG&E/SoCalGas fully understand Long Beach's frustration as they themselves are subject to the same requirements at every BCAP proceeding. Nonetheless, experiencing difficulty in forecasting gas demand and reservation amount is not a valid reason to reject the TLS rate. Long Beach claims that because core demand is extremely weather-sensitive, the TLS SFV-Volumetric rate will increase its average rate. Long Beach suggests that a transmission class average volumetric rate is more appropriate since SDG&E'SoCalGas' core customers are provided volumetric rates for backbone service and are not subject to any reservation requirement (p.16). However, Long Beach refuses to be billed at core rate. It appears that Long Beach wishes to be treated like a noncore customer for purposes of the costs allocated to Long Beach, but like a core customer for rate design purposes.

Moreover, Long Beach errs in stating that SDG&E/SoCalGas core customers are provided volumetric rates for backbone service. SDG&E/SoCalGas core customers are allocated a fixed amount of transmission costs regardless of actual core usage. Thus, if Long Beach were to be treated in a manner identical to SDG&E/SoCalGas' core, it would be allocated a fixed dollar amount based upon the various demand measures used to allocate costs to SDG&E/SoCalGas core. This aspect of allocation is very similar to that of the TLS rate design. Long Beach's argument that the TLS will raise its average rate appears to be predicated on the assumption of its inability to forecast demand and manage risk. Forecasting demand and managing financial risk are tasks undertaken by every utility in the normal course of doing business; like all utilities, Long Beach must accept this responsibility rather than seeking to deflect it by seeking a more advantageous rate design.

F. SDG&E/SoCalGas' Development of the TLS Reservation Rate is Sound

SCGC witness Yap argues that SDG&E/SoCalGas' denominator of 1390 Mdth/d is overstated by 47% - that a figure of 947 MMdth/d should be used because that is consistent with forecasted December monthly average demand for the TLS customers. SDG&E/SoCalGas'

higher figure represents the maximum amount of capacity that can be reserved for TLS customers on an annual, 365-day basis without jeopardizing core service. That is exactly the type of denominator that should be used in trying to develop a pipeline-like SFV rate design. New interstate pipelines develop their SFV rates by rate by dividing total cost by the capacity of the pipeline system in question. (The only difference is that not as much excess capacity is built into interstate pipe capacity as exists on the SoCalGas system.)

Essentially, SDG&E/SoCalGas have subtracted core 1-10 year peak day demand (plus a proportionate share of excess capacity for the core) from their maximum sendout capacity of 6 Bcf to derive the maximum amount of redelivery capacity that can be provided to TLS customers for 365 days throughout the year. Whether these customers will subscribe to that capacity level or will have peak usage in December equal to that figure is irrelevant. Whether this number is consistent with marginal demand measures used for cost allocation purposes is irrelevant. What is relevant is the answer to the following question: how much of the 6 Bcf of maximum redelivery capacity is not needed by the core and distribution customers on a peak day with a certain safety margin? The result is the amount of capacity that should be used for a SFV rate design. Ms. Yap attempts to justify use of the lowest denominator possible so that the SFV rate is basically no different than an annual average volumetric rate – contrary to the Commission's intent to close the regulatory gap.

Artificially raising the TLS reservation rate would tend to make SDG&E/SoCalGas' service appear less competitive with prospective interstate pipelines and would therefore provide customers a greater incentive to baseload their demand on an interstate pipeline and swing off SDG&E/SoCalGas' firm-like interruptible service. The methodology employed by SDG&E/SoCalGas to set the TLS reservation rate is appropriate. The TLS rate is as similar to an interstate pipeline as possible (while accurately reflecting the inherent differences between utility and interstate pipeline service obligations) and successfully narrows the regulatory gap. The TLS rate therefore sends appropriate price signals to customers to discourage uneconomic bypass.

SCE witness, Dr. Alexander, and Ms. Yap both recommend maintaining a Peaking Service for transmission-served EG customers, who they recommend be exempted from the TLS rate. SDG&E/SoCalGas agree that unless the regulatory gap is narrowed or eliminated with a new rate design, such as the proposed TLS service, an effective Peaking Service tariff must be in place to discourage uneconomic bypass. The Commission should reject the proposal to exempt EGs from the TLS service. The TLS proposal can successfully narrow the regulatory gap between SDG&E/SoCalGas and the interstate pipelines, and should be applied equally to all transmission level customers. This conclusion is not based on a cost-of-service criterion, but rather on the higher probability associated with transmission customers of partially bypassing SDG&E/SoCalGas' transmission system.

The alternative peaking rate, or G-MSA, as outlined by SCE witness, Dr. Alexander, is also flawed and unresponsive to the Commission's directive to close the regulatory gap. SDG&E/SoCalGas ' proposal allows a customer considering the bypass of its baseload to compare the 10-11 cent/Dth reservation charge (plus variable charges) of the TLS rate with the equivalent reservation charge and variable charges of a competing interstate pipeline. If the competing pipeline has lower rates, then the partial bypass is, by definition, economic and the customer will make the choice to bypass SDG&E/SoCalGas' system with its baseload. Any swing load that partial bypass customer retains on the SDG&E/SoCalGas system would be subject to the same volumetric rate as remaining, or non-bypassed, customers on the SDG&E/SoCalGas system who choose the volumetric rate option. By definition, the cost of serving the swing load of a customer who chooses partial bypass would be cost-based *(i.e.,* related to the cost-based allocation of margin to TLS customers), non-punitive and non-discriminatory.

By contrast, the G-MSA as outlined by Dr. Alexander does not send the correct price signals to a customer considering partial bypass through the closing of the rate design gap with the interstate pipelines and the appropriate pricing of remaining, swing load. Rather, it is an attempt to recover marginal costs from a customer who has already made an uneconomic partial bypass decision. Dr. Alexander's proposal is therefore unresponsive to the Commission's directions in the FAR decision.

Dr. Alexander's proposal focuses on the potential benefits of incremental usage and revenue from partially bypassed customers by lowering the SDG&E/SoCalGas volumetric rate rather than ensuring that uneconomic bypass does not appear to be economic to begin with. SDG&E/SoCalGas's TLS proposal, on the other hand, focuses on closing or narrowing the regulatory gap sufficiently to discourage uneconomic bypass.

SDG&E/SoCalGas believe that the proposed TLS rate design offers greater benefit to ratepayers and fully complies with the Commission's directive by narrowing the regulatory gap, rather than competing for marginal revenue that might be available after the initial uneconomic decision is made by the partially bypassing customer.

III. Proposals to Reduce Term of Full-Requirements Service

IP/CCC/CMTA/Watson witness, Mr. Beach, and SCGC witness, Ms. Yap, propose shortening the term for volumetric service from six years to three years. Ms. Yap goes further to propose 1 year evergreen contracts for all-volumetric firm service.

Ms. Yap argues that asking customers to commit to taking utility firm all-volumetric service for a period of six years will not provide better information regarding customers' plans than asking them to commit to three years or 1-year. SDG&E/SoCalGas believe that the opposite is true. Certainly, if a customer is considering leaving the utility system for alternative service sometime during the following 2-5 years, the six year term may influence the customer's decision as to the utility service it elects to take. With a six year commitment, SDG&E/SoCalGas could use that customer's election, as well as any other information the customer might provide, for planning purposes. Because it typically requires several years for a new interstate pipeline to be marketed, planned, approved and built, it should not be burdensome for a customer to commit to a six year term for all-volumetric service relative to the competitive alternative.

Ms. Yap argues that because the spacing between cost allocation proceedings is not related to contracting, there is no need to match the two, and that contract terms should be 1-2 years. Mr. Beach argues that because cost allocation proceedings are proposed for every three years, contract terms should be three years in order to match. Clearly, these differing arguments meet at the level where both parties agree merely that they would prefer a shorter term for all-volumetric service. For the reasons set forth below, however, these arguments should be rejected by the Commission.

Ms. Yap's argument that the proposal for a six-year term for firm all-volumetric is a "thinly disguised attempt to shift risk from SDG&E/SoCalGas' shareholders to customers" misses the mark entirely. The proposal is intended to protect captive customers from the increased costs they would bear if the utilities' rates and service offerings encourage uneconomic bypass by non-core customers.[24] The six-year term helps to narrow the regulatory gap, especially when applied only with the firm, full requirements, all-volumetric rate. Under a full-requirements contract, similar to today's contracts, a customer pays for only what they use (all-volumetric rate), and pays a use-or-pay only if the customer elects to use unauthorized alternate fuels or elects to bypass during the term of the contract. Therefore, these longer term contracts do not "create a significant cost burden to customers." Importantly, however, they do narrow the regulatory gap by asking customers to undertake a minimum commitment to remain with the utility for a reasonable term.

Mr. Beach also argues that a six-year term is too long because (a) a customer cannot confirm FARs for the full period, (b) a customer's load profile could change and the customer may wish to move from the all-volumetric rate to the reservation charge option every three years, (c) the Commission hasn't approved longer customer commitments in the past, and (d) the proposed reservation rate structure sufficiently fills the regulatory gap, such that extended contract terms are not necessary.

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[24] Utility shareholders are not at risk for departing load (*e.g.* to bypass) as Ms. Yap seems to suggest, and Ms. Yap is not proposing the utility shareholders be placed at such risk. If shareholders were to be placed at some risk for noncore throughput, loss of load to bypass would impact shareholders only to the extent the load loss was not forecasted in a cost allocation proceeding. Because bypass decisions by customers and the development of new interstate pipeline extension usually have a relatively long lead time, forecasting the load loss would not be a major problem and so has not factored into our proposal at all.

With regard to Mr. Beach's argument concerning FARs, because the six-year term service does not require a financial commitment from a customer and only obligates a customer to take local transmission service from the utility during the term of the agreement, it is not clear how the ability to match FARs is pertinent to this issue. SDG&E/SoCalGas do not perceive the availability of FARs to be a deciding factor on whether a customer elects full-requirements, all-volumetric service. On the issue of changes in load profile, SDG&E/SoCalGas generally agree that if a customer's load profile changes such that the customer wishes to increase its reservation service after the first 3-year term, the customer should be able to make such a change to its contract at the appropriate reservation charge anniversary dates. Finally, regarding the need for and Commission precedent concerning extended contract terms, the Commission's clear intent is to close or narrow the regulatory gap sufficiently to discourage uneconomic bypass. Thus, in addition to following the Commission's directive to propose rates aimed at minimizing the regulatory gap, SDG&E/SoCalGas have sought to address the regulatory gap created by differences in the service terms offered by SDG&E/SoCalGas and the interstate pipelines. Mr. Beach's citation to D.06-09-039 is inapposite. In that case, there was concern because customers in potentially constrained areas were asked for a financial commitment. The instant proposal, by contrast, would not require financial commitments from customers for firm, full-requirements, all-volumetric service.

In general, the calls to reduce the proposed terms for service are in conflict with the Commission's directive to close or narrow the regulatory gap between utility and interstate pipeline service. As Ms Yap suggests, pipelines would typically require commitments longer than 3-years for firm reservation service, however Ms Yap provides no evidence that interstate pipelines typically provide all-volumetric firm service "on a short-term basis" or at all. Indeed, SDG&E and SoCalGas are not aware of any interstate pipeline offering all-volumetric firm service.

A literal interpretation of closing the regulatory gap would require that the TLS have very long (*e.g*. 15-year) terms for firm reservation service and offer no all-volumetric firm service at all. SDG&E/SoCalGas recognized that this would be a disruptive and unwelcome change for customers, who have long enjoyed service under the current all-volumetric rate design. SDG&E/SoCalGas believe the proposed 3 and 6 year terms for reservation and firm all-volumetric rate service, respectively, are a reasonable balance between meeting customer needs and narrowing the regulatory gap. SDG&E/SoCalGas' TLS proposal offers all-volumetric firm service as an option for those customers who value firm service but prefer not to make a financial commitment (in the form of a reservation charge). However, SDG&E/SoCalGas recognize that offering an all-volumetric rate option creates a challenge to the effort to narrow the regulatory gap. To meet that challenge, SDG&E/SoCalGas propose only that customers electing all-volumetric firm service make a commitment to take their full natural gas transportation requirements from the utility. This is identical to current full-requirements service, but for the extension of the term by four years, which is significantly less than the term that would be required by a typical interstate pipeline for reservation service. Contrary to Ms. Yap's testimony, there is no financial commitment expected from customers electing the all-volumetric, full requirements service, which is similar to today's firm full requirements service.

IV. Proposal to Eliminate the Sempra-wide Rate for Distribution Service EG Customers

SCE witness, Dr. Alexander, argues that the Sempra-wide EG rate should be eliminated. He defines the Sempra-wide EG rate (p. 31 of his testimony) as follows: "Unlike other customers, who pay a different rate in the SoCalGas and SDG&E service territories, EG customers of both utilities pay the same rates for distribution service in the two territories, despite identified differences in the cost of service to the groups." He states that this causes a cross subsidy of SDG&E's EG customers by SoCalGas' EG customers.

Although Dr. Alexander previously testified against the Sempra-wide EG rate in SoCalGas' System Integration Application (A.04-12-004), it has remained in effect since the Commission ruled in favor of the Sempra-wide EG rate in D.00-04-006. As a result of System Integration, the transmission costs of SDG&E and SoCalGas, respectively, were combined into a single system-wide transmission rate. Since the difference in costs between the two utilities has changed, the Sempra-wide adjustment would only apply to EG customers taking service off of the two utilities' distribution systems.

On page 32 of his testimony, Dr. Alexander argues that the Commission's support for the Sempra-wide EWG rate in D.00-04-006 "… should be reconsidered, as it was erroneous in light of the circumstances at the time have changed. The decision to permit that subsidy was based on arguments concerning the Power Exchange (PX), which no longer exists and therefore whatever rationale may have existed for the Sempra-wide rate likewise no longer exists." Based on Attachment MSA-5, comprised of portions of Dr. Alexander's testimony in A.04-12-004, the key aspect of the PX that was crucial to those arguments was that "… all generators in California were required to offer their electricity for sale through the PX and all generators whose bids were successful were paid the same market clearing price." Dr. Alexander is implying that, since the PX no longer exists, the centralized day-ahead electric market that determined the single market clearing energy cost also does not exist. Hence, higher gas transportation costs would not place SDG&E gas-fired generation at a competitive bidding disadvantage and could not lead to higher PX or market clearing prices. With the demise of the PX, the day-ahead market did revert to a bilateral market. However, with the implementation of the new market rate design for the California energy market, a bid-based, day-ahead energy market will soon be reestablished.

On March 31, 2009, the California ISO will initiate its long awaited Market Redesign and Technology Update (MRTU). The central tenet of the market redesign is to institute a day-ahead energy market with locational marginal prices (LMP). That is, a separate price (LMP) for each demand and supply node will be calculated. The LMP is comprised of three components, an energy price, full marginal loses, and a congestion price. The LMP will be determined from a bid-based, security constrained, economic dispatch. Generators and load will bid into a centralized day-ahead energy market that will determine a single market clearing energy cost only for those participants in the day-ahead market. A successful bid is one that is less than the highest bid needed to clear the market and meets all transmission constraints. In the absence of congestion, all LMPs will reflect the single market clearing price adjusted for losses. This is exactly the same result the PX was intended to supply. Hence, Dr. Alexander's claim that the demise of the PX (*i.e.*, the demise of a single market clearing price) is a fundamental change that justifies the elimination of the Sempra-wide EG rate is not valid.

V. Proposal for State Regulatory Fee Exemption

SCE witness, Mr. Roney, recommends that SoCalGas not apply Schedule G-SRF (SRF) for gas transported to Mountainview Power Company, LLC (Mountainview) and to plants owned by third-party generators with which SCE has tolling arrangements. Mr. Roney confirms and SoCalGas agrees that SoCalGas is administering its tariff correctly, and that power plants identified as being part of the SCE public utility are exempted from SRF charges.

SDG&E/SoCalGas recommend that the Commission gather more financial data to estimate the revenue impact of exempting non-utility-owned electric generation plants that sell their power to a public electric utility, such as SCE, prior to making a determination on this issue. SDG&E/SoCalGas' primary interest is that the impact of cost reallocation to other customers, if any, be considered by the Commission before granting the exemption.

VI. SCGC Proposal Regarding Treatment of EOR Customers

In her direct testimony, SCGC witness, Ms. Yap, proposes to change the method for the allocation of costs and for the revenue treatment for the EOR market. In the current method, adopted by the Commission in D.87-05-046, no costs are allocated to the EOR class of customers but, after netting out the short run marginal costs from the EOR revenue, 95% of the revenue is used to offset the costs allocated to all other customer classes, with the other 5% of the revenue going to SDG&E/SoCalGas' shareholders. SCGC is proposing to treat the EOR class like other classes by basing its rate on the costs allocated to the class and eliminating the sharing of revenue. SoCalGas proposes to leave the current system in place.

Ms. Yap correctly points out on page 22 of her testimony, "[t]he Commission adopted the 95/5 treatment at a time when the EOR industry was on the rise and SoCalGas was attempting to serve as much of the market as possible." In these respects, circumstances are no different today; *i.e* the EOR industry is on the rise and SoCalGas is still attempting to serve as much of the market as possible. Therefore, SoCalGas sees no reason to change the cost allocation and revenue treatment of the EOR market. While SoCalGas may have lost a portion of this load to bypass, the EOR industry itself is growing and SoCalGas is serving a portion of this new load, as indicated in the testimony of SDG&E/SoCalGas witness, Mr. Emmrich (pp. 9 and 10). Since the beginning of 2006, SoCalGas has added six new customers, representing about 20% of the number of EOR customers and about 30 % of the EOR load included in the 2009 BCAP. The rules and rate treatment established in D.87-05-046 allowed SoCalGas to negotiate rates with EOR customers to attract and retain them on the system and gave SoCalGas an incentive to do so. At this time, these rules are very helpful in incenting SoCalGas to, again, negotiate with new EOR customers as well as existing EOR customers that are considering bypass. Whether or not SoCalGas decides to negotiate contracts with the EOR customers, having this rate treatment in place gives SoCalGas the option to negotiate without incurring unnecessary risk.

The Commission offered two reasons for its decision to adopt the rules established in D.87-05-046: "First, we conclude that the utilities should not be presented with a near certain undercollection for every volume of EOR gas transported; to the contrary, they must have a strong incentive to serve the EOR market for the benefit of all ratepayers. Second, we believe that the economics of the EOR market and the possibility of bypass make it clear that the market is not likely to be served by transmission services priced at fully allocated embedded cost as we have calculated it."[25] These reasons are still valid today. Bypass to interstate pipelines is still a reality today, as pipelines continue to expand. Such bypass would lead to higher rates for other SDG&E/SoCalGas ratepayers. SDG&E/SoCalGas have designed the TLS rate to be competitive with the interstate pipelines by narrowing the regulatory gap, as ordered by the Commission in D.06-12-031. However, SCGC opposes the TLS rate and, apparently, SDG&E/SoCalGas' attempt to narrow the regulatory gap. It also opposes any incentive for SoCalGas to retain the EOR load. Even with the TLS rate, there will continue to be situations where SoCalGas may need the flexibility to negotiate discounted contracts. For example, all six of SoCalGas' new EOR customers mentioned above are on the distribution system, rather than the transmission system, so they would not have access to the TLS rate. Thus, as their loads grow, SoCalGas may be challenged to create competitive options to retain them on its system.

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[25] D.87-05-046, p.19.

The Commission should therefore not change the rules for the EOR market, but if the rules are changed the Commission should adopt the policy of 100% balancing account treatment for all revenues, as explained in my prepared direct testimony (pp. 13-14).

VII. Proposal for Providing Firm, Full-Requirements Service to Customers Importing Landfill or Digester Gas

SCGC witness, Ms. Yap, proposes that EG customers who burn digester/landfill gas should not be required to take service under the partial requirements tariff, and accuses SoCalGas of "penalizing" the City of Glendale (Glendale) by serving its power plant under a partial requirements tariff. Ms. Yap points out what has been true for many years – the Glendale power plant satisfies a portion of its gas requirements with landfill gas. Ms. Yap seems to imply that SoCalGas' tariff service is impeding Glendale's ability to use landfill gas at its power plant. Actual operational evidence at the Glendale generating facility is to the contrary.

Ms. Yap's portrayal is wholly inaccurate. SoCalGas serves Glendale under an interruptible service tariff. To the extent Glendale prefers firm service, it would qualify for partial requirements firm service since it does not qualify for full requirements firm service as provided in SoCalGas' GT-F tariff schedule. SoCalGas Tariff Rule 1, Definitions defines Full Requirements Service as "an option for …firm intrastate transmission customers. Full requirements customers choose to have all of their fossil fuel requirements satisfied by natural gas…. Such customers are not subject to use-or-pay charges except to the extent that unauthorized alternate fuel use or bypass occurs. Full requirements customers are prohibited from using alternate fuels or bypass pipeline service except: (1) in the event of curtailment, (2) to test alternate fuel systems, or (3) where Utility has provided prior written authorization for the use of alternate fuels or bypass. Any fuel produced on-site by the customer can be used by the producer without penalty.

SoCalGas Tariff Rule 1 Definitions further defines alternate fuel as, "Any fuel, gaseous, liquid, or solid, that may be used in lieu of natural gas." Partial Requirements firm service as offered in SoCalGas' GT-F tariff requires a customer to specify an annual quantity for firm service, and there is a modest use-or-pay commitment associated with that quantity, which is nowhere defined as a “penalty” and has been a long accepted service for noncore customers who wish to also burn alternate fuels. Clearly, SoCalGas is providing service and service options to Glendale that are completely consistent with its tariffs and without discrimination.

SoCalGas disagrees with the recommendation that it be required to offer a blanket exception to its long-standing partial requirements firm service tariff for a specific alternate fuel type and customer, such as landfill gas for electric generation. At this time, requests for deviations from this tariff are rare. In fact, SCGC’s intent in raising this issue in this proceeding is difficult to discern, particularly where Glendale itself has not approached SoCalGas about this matter despite our close working relationship. SoCalGas is open to working with a Glendale and other customers to seek Commission approval for deviations to its tariff service as needed, on a case by case basis, if it appears that the straightforward application of the tariff does not fit.

SDG&E/SoCalGas do not believe that this is an issue that should be addressed in a cost allocation proceeding until and unless evidence arises that the need for deviations is significant such that it merits a more general review of SoCalGas tariff service. In the meanwhile, SDG&E/SoCalGas would welcome the opportunity to work with customers in order to develop a solution and associated tariff deviation and to then seek approval from the Commission via advice letter.[26]

VIII. Proposal to Allocate Only 37% of Transmission Costs to Backbone

SDG&E/SoCalGas employed a two-step process to develop the estimate that 57% of total transmission cost is associated with backbone transmission. First, SDG&E/SoCalGas estimated that 75% of their transmission costs serve a backbone function. Second, SDG&E/SoCalGas took into account that on an annual average basis, 928 MMcfd of local demand is served through backbone facilities. 928 MMcfd is 24% of SDG&E/SoCalGas’ 3875 MMcfd of backbone transmission capacity. Therefore, 24% of the annual backbone costs was reallocated to local

[26] For example, in 2004 the CPUC approved a SoCalGas request for tariff deviation to accommodate a large EG customer’s use of a nearby refiner’s excess/waste refinery gas and still retain firm, full requirements gas service. Advice Letter No. 3349, Request for Service Deviation from Tariff Schedule GT-F, Firm Interstate Transmission Service, for El Segundo Power, LLC.

transmission, thus leaving 76% (100% - 24%) of the annual backbone costs. This results in a final 57% allocation of costs to backbone: 75% x 76% = 57%.

SCGC witness Yap accepts the first step outlined above. She inaccurately assumes, however, that 51% of the annual cost of backbone facilities, not 24%, should be reallocated to local transmission. She reaches this erroneous conclusion by taking a 1-in-10 year peak day level of local demand served off backbone (2 Bcfd) and assuming that level of demand exists for 365 days every year. 2000 MMcf of demand divided by 3875 MMcf of backbone capacity translates to 51%, thus leaving 49% (100% - 51%) of non-local demand on the backbone. Therefore, SCGC only allocates 37% of total annual transmission costs to backbone: 75% x 49% = 37%.

Ms. Yap's approach is flawed. It assumes that a 1-in-10 year cold day level of local demand is served 365 days every year off of the backbone transmission system and allocates annual transmission costs on that basis. Its methodology completely ignores the role of storage in meeting local demand. Obviously, on a 1-in-10 year cold day, all demand is served through a combination of all utility assets: backbone transmission, local transmission, distribution, and storage facilities. Simply because the utility system is designed to serve a 1-in-10 year cold day level of demand should not lead to the conclusion that costs should properly be allocated around this rare event. Since the assets are used year-round, the proper allocation should be based on the annual average demand, just as SDG&E/SoCalGas have proposed. Thus, SCGC's calculation is based upon incorrect assumptions and must be rejected.

This concludes my prepared rebuttal testimony.

ATTACHMENT A

QUESTION 9:

1 Mr. Schwecke, on page 17-18, notes that the Omnibus decision adopted a mechanism to track the costs of gas supplies needed for the minimum flowing supply requirement. He proposes the Southern System Flow Order as one tool to maintain this minimum flowing requirement. The following questions seek additional clarification to better understand how SoCalGas has dealt with Southern System reliability issues in the past.

1.1 Identify all efforts SoCalGas has taken in the past to address Southern System reliability issues.

1.2 Identify all receipt points on the SoCalGas/SDG&E system which have a minimum flowing requirement.

1.3 Quantify the amount of natural gas supplies that were needed to maintain the Blythe minimum flow requirement from 2001 through 2007.

1.4 Identify the interstate and intra-state pipeline systems that could potentially provide gas supplies to meet minimum-flow requirements at: (1) the Blythe receipt point; and (2) the Otay Mesa receipt point.

1.5 Provide any analyses SoCalGas or SDG&E have performed on southern system reliability.

1.6 Is there a minimum amount of natural gas supplies which must flow through the Otay Mesa receipt point to maintain southern system reliability?

1.7 Under what circumstances can gas supplies flowing through the Otay Mesa receipt point be used to satisfy the minimum flowing requirement at the Blythe receipt point?

1.8 Do natural gas supplies flowing through the Otay Mesa receipt point offset the Blythe minimum flowing supply requirement in the same manner as natural gas supplies flowing though the Blythe receipt point? If not, please explain why not.

1.9 Identify the type of system or operational changes that would require the institution of minimum flowing requirements at receipt points other than Blythe.

1.10 Could there be a minimum flowing supply requirement through the Otay Mesa receipt point separate from the Blythe minimum flow requirement?

RESPONSE 9:

9.1 First, SoCalGas uses the Chino and Prado crossovers to their maximum capability in order to deliver North Desert and/or storage supplies onto the Southern System. Next, SoCalGas has had the ability to call on the Utility Gas Procurement Department to take action, including purchases of supplies, to ensure that the minimum flowing supply requirement of the southern system is met.

9.2 Only the Southern System currently has a minimum flowing supply requirement. The receipt points on the Southern System are Ehrenburg/Blythe and Otay Mesa.

9.3 Please refer to Response 6.1.

9.4 El Paso Pipeline and North Baja Pipeline interconnect with the SoCalGas system at Ehrenburg/Blythe; the TGN Pipeline interconnects with the SDG&E system at Otay Mesa. Any interstate pipeline that can supply the El Paso, North Baja, or TGN pipelines could provide gas supplies to meet the minimum flowing supply requirements at these locations.

9.5 Upon consultation, IP clarified its request as:

"Provide any analyses performed by SoCalGas or SDG&E that have informed the minimum flowing requirement adopted in the Omnibus proceeding or the Southern System Flow Order proposed in this proceeding, including without limitation:

"Any analysis or study of the amount of flowing supplies necessary to maintain Southern System reliability;

"Any analysis or study of the infrastructure that would be required to limit or avoid implementation of the SSFO;

"Any analysis or study of operational or demand-side alternatives (other than the SSFO) that can be used to address the minimum flowing requirement; and

"Any analysis or study of operational alternatives that can be used to limit or avoid implementation of the SSFO."

SoCalGas and SDG&E have not performed any analyses specific to the minimum flowing supply requirement and treatment adopted in the Omnibus proceeding or since proposing the Southern System Flow Order (SSFO) in this proceeding. Southern System reliability is a condition of any hydraulic analysis performed on the SoCalGas/SDG&E gas transmission system, although analyses or studies specifically addressing the Southern System minimum flowing supply requirement have not been performed, and no report has been prepared on this topic. Infrastructure improvements undertaken by SoCalGas, such as the rebuilding of the Chino and Prado crossovers to increase the capacity to deliver North Desert and/or storage supplies onto the Southern System mentioned in Response 9.1, were identified as the result of other analyses and studies.

As explained in Response 6.3 and Response 6.4, the minimum flowing supply requirement is determined by the Utility Gas Control department several times each day. The analysis performed utilizes the information available at the time on available gas supplies and system demand along with other influencing factors such the weather forecast. Given the real time nature of the minimum flow supply requirement, a study is not required to make this determination.

SoCalGas and SDG&E have identified as an alternative to a Southern System minimum flowing supply requirement the construction of a new pipeline linking the North Desert transmission system and the Southern System. This pipeline, consisting of approximately 100 miles of 36-inch diameter pipeline, is estimated to cost in excess of $300 million. A hydraulic calculation was performed to confirm the ability of this pipeline to transport the necessary volumes, but a report was not prepared.

SoCalGas and SDG&E have not explored demand-side alternatives to the Southern System minimum flowing supply requirement, and have not been able to identify any further operational efforts to limit or avoid implementation of a SSFO, other than curtailment of end-use customer demand.

9.6 Not currently.

9.7 Gas supplies delivered at Otay Mesa can be used to satisfy the Southern System minimum flowing supply requirement once SoCalGas/SDG&E gain operational experience with the Otay Mesa receipt point and confidence with supplies delivered at that location. In A.04-12-004, SoCalGas/SDG&E stated the following:

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Q Good afternoon, Mr. Bisi. I'm Mike Florio representing
TURN in this proceeding.  I would like to go back to a
subject you were discussing with Mr. Leslie regarding the
physical assurance that you would need at Otay Mesa in
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order to meet all or a portion of your southern system requirements from that location. Could you describe in a little more detail what you would need to see in order to count deliveries at Otay Mesa toward your southern system requirements?

A Sure. As an operator what I would need to see would be that Otay Mesa and its shippers schedule what they intend to deliver and deliver what they intend to schedule. I would need to see that they are going to deliver whichever volumes they request on a constant uniform hourly basis. And I would need to see that for some period of time.

Q Would contractual guarantees be sufficient to provide that level of assurance?

A As an operator, not in my opinion.

Q So you would want a combination of contractual and actual experience?

A Yes.

Q If gas begins flowing at Otay Mesa and you are consistently seeing, let's just say, 400 a day coming in at that receipt point, after some period of time you might be confident enough that you could rely on that supply and perhaps reduce your minimum requirement at Blythe?

A Yes.

Q Do you have any sense of how much time that would take?

A No.

Q Are there any assurances that you would need from the pipeline delivering to Otay Mesa as opposed to the shippers who are providing the gas?

A Yes.

Q What would those be?

A It would be the same assurances.

Q So in essence it's a show me test?

A Exactly.

[Cross examination transcript, A.04-12-004, September 12, 2005]

9.8 Supplies delivered at Otay Mesa would support the Southern System minimum flowing supply requirement in the same manner as supplies delivered at Blythe/Ehrenberg once SoCalGas/SDG&E have gained operational experience with the Otay Mesa receipt point and confidence in supplies delivered at that location, as explained in Response 9.7. In A.04-12-004, SoCalGas/SDG&E stated the following:

Q To the extent that SDG&E demand can be served through Otay Mesa, does that affect or will that affect the minimum flows, flow obligation, on the Blythe system? Southern system. Excuse me.

A It might. It might. Before gas operations would be comfortable replacing a Blythe minimum flow supply requirement with an Otay Mesa flowing supply requirement, we would want to have physical assurance or reliability. We want to know the state of the reliability of those supplies, both from the supplier standpoint and the supplying pipeline standpoint.

Q And how do you measure the security of the supply delivered at Otay Mesa?

A I'm really not sure other than experience would be one measure.

Q How do you assure the delivery of gas supplies at Blythe to meet minimum flow requirements?

A Well, El Paso has been a long time supplier to the SoCalGas system. But even more importantly, if supplies at Blythe were to suddenly cease from El Paso, the Blythe and Ehrenberg receipt points are not located right at a major load center. And there is time for SoCalGas operations to react to that loss of supply, implementing noncore curtailment, trying to reconfigure our system to bring gas on, withdrawal to get the Line 4000 and 4002 systems separated to support backflow operations through the crossover. There's time to react to that loss. At Otay Mesa there would be no time.|

[Cross examination transcript, A.04-12-004, September 12, 2005]

9.9 SoCalGas/SDG&E have not identified a need to implement a minimum flowing supply requirement at any receipt point other than Blythe/Ehrenberg. Generally, any new demand which requires supply delivered at a specific location on the system may result in a new minimum flowing supply requirement.

9.10 Yes, refer to Response 9.9.