SDG&E Comments on SDREO Report[1]

SDREO Report Statement	Comment
ecutive Summary	
kground. The goal of the study.	The report did not address alternative resource development approaches. The report contained no different approaches. It appears the sole analysis was to compare various renewable and alternative supplies to a proxy for future costs.
Problem - San Diego County is one of the top three residential cost kets and in the top six commercial cost markets in the United States. The ion also faces very high natural gas transmission and city gate prices – often her than other regions. Many factors drive these costs.	The report makes no effort to determine what the drivers are of these costs. It makes no determination as to how costs will be impacted if its recommendations are carried out.
G&E has indicated it no longer deems its role to be the regional energy nner, and the Public Utilities Commission's regulatory scope has been iled in lieu of market-based pricing.	SDG&E has always been and continues to be responsible for electric transmission and distribution planning. SDG&E is also responsible for natural gas acquisition for a majority of the region's gas customers as well as for gas infrastructure planning. SDG&E is currently engaging in substantial electric commodity acquisition planning, which combined with the CDWR contracts will meet all of the regions energy needs. The company has recently proposed purchases of significant energy from renewable sources.
stions exist about how best to price EG natural gas.	EG customers purchase their own gas at market prices on the open market. No utility or other entity is required to "price" natural gas.
apter 2 Situation Analysis	
eral Comment	Much has happened since this report was first started, thus the situation analysis is out-of-date.
ion 2.1.2 The opening of market trading created congestion.	Limitations on ability to use transmission lines existed before April 1998, when the markets were opened and it will continue. Expanding transmission will reduce the amount of congestion and increase access to other sources of supply.

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e referenced location for each statement is just one location in the report where the statement is made. In a large number of cases the statement is repeated where in the report. SDG&E has not cross-referenced these other locations but the same comments would apply. In some cases, SDG&E has also just enced the first sentence in a section. Given the comments, it may require the entire paragraph to be modified. SDG&E has also not rewritten conclusions or mmendations, although many will need to be modified for the corrections.

ion 2.1.2 When price caps were lifted in San Diego, retail prices soared rly 50%.	When price caps were lifted in the summer of 1999, prices for SDG&E's customers dropped. It was almost a year later when the wholesale market prices increased that customer's prices increased. Many of the items in Table 2-1, which tie back to other sections of the report, are in error. This table needs to be updated to reflect the issues in this table.
ion 2.1.2 Average electricity rates are anticipated to remain at high levels ugh at least the end of the decade.	This section is confusing as it mixes retail rates and wholesale prices. Average retail prices will remain at relatively high levels because the state has chosen to lock in contracts as a means of stabilizing prices and ensuring supply. These contracts address the very concern expressed in the report. New sources of supply, added as need for them arises, are likely to reduce the average cost of energy throughout the latter half of the decade. The report contains no data to assess the recommendations impact on prices.
ion 2.1.3 historically, supply reserve margins were maintained at double s. In 2000-2001, California's margins were frequently below 5 percent.	This confuses two different concepts: Planning reserve margins, which have been typically above 10%, and operating reserve margins – i.e. what is available at any given time, which are planned to be at 7%. It is not unusual for operating reserves to be below 10% to avoid unnecessary operating costs associated with keeping units available.
ion 2.1.3 It appears that the energy industry credit crisis will continue to be imary driver of the availability of resources for at least the next five years.	This mixes the concepts of resource availability and development of new resources. The availability of credit is an extremely important issue but the credit crisis is not the only driver in the development of new units. The price of wholesale power is also a factor along with the willingness of retail power providers to sign contracts with wholesale power suppliers. If market prices, contract terms, and the states business and regulatory climate are favorable, credit can be more easily obtained.
ion 2.2 Major risk include: Congestion and potentially higher transmission es from importing power into the region as a result of locational marginal es (LMP)	Congestion only occurs because lower cost power is attempting to flow into a higher cost area; however the transmission is limited. It is the lack of transmission to the broader market that results in higher costs. Without transmission, areas of high production costs show higher "locational marginal prices". This does not result in higher transmission prices and the higher costs are not a result of LMP. So long as transmission is limited and the region is a high cost area to develop new power plants, costs in the region will be higher than surrounding areas.

ion 2.2 Major risks include "inflated regional capacity values because of ted markets to sell "in-region" generation to the broader western market."	Limited export capability will not raise local capacity costs directly, but it will reduce the interest of suppliers to build locally if they cannot access regional markets. If this is a concern, the report needs to explain why it does not endorse transmission access to the market, which would increase the ability of local plants to export and make the area more attractive for development.
ion 2.2 Major risks include: Continued electric generation price volatility to limited competitive supply of natural gas to the region.	This is an unsupported and erroneous statement. Electric price volatility can be mitigated through contract provisions and resource selection, both of which are independent of natural gas. The statement of limited competitive supply of natural gas is in conflict with the report body that points out the region has access to all supply basins in the western US and Canada.
ion 2.5.1.8 Bi-national solutions should be considered.	The statement implies that bi-national solutions have not been considered in the past or currently. SDG&E and CFE have purchased and sold power to each other for years. Bi-national solutions have been implemented through the construction of new power plants that serve both CFE and US loads, and natural gas pipelines in Mexico.
le 2-1 Current energy infrastructure decisions are evaluated in an isolated mented manner - often without public and community discussion.	All siting of major transmission and generation is subject to regulatory approval, and California Permit Streamlining Act, was designed to eliminate the fragmented permitting process that previously existed. In addition, the California ISO (which is required to hold public meetings) considers the need for new infrastructure from a reliability standpoint. The CEC, which license new plants, holds open proceedings. The CPUC process is also open to the public. The substantial amount of community involvement in Valley-Rainbow shows that there is public discussion; and refutes that statement that infrastructure decisions are made in an isolated manner.
le 2-1 Significant new power plant projects and other major natural gas sumers will either have to accept non-firm contracts, be willing to enter into -term contracts, and be willing to pay a higher share of incremental natural infrastructure upgrade requirements.	This statement is false and does not match CPUC approved rules or any SDG&E proposal, which would have to be approved by the CPUC prior to being implemented.

hapter 3 Natural Gas	
neral Comment	The sponsors did not conduct any gas system modeling, thus all conclusion reached regarding the ability of the system to meet new power plant load are speculative and not based on analysis. SDG&E provided analysis to the developers of the Palomar plant that showed the system could serve that facility, even if Otay Mesa was constructed.
tion 3.1 "The western United States, and especially California, is dergoing a tremendous increase in demand for natural gas as plans unfold to ld several thousand megawatts of new natural gas-fired electric generating acity.	This statement raises no questions about the local system. Only local generation has the potential to affect the local delivery system's delivery capability. Therefore, the construction of natural gas fired generation outside the region has no impact on regional planning. Also with the completion of Baja Norte SDG&E's gas system is serving less generation demand than it did two years ago.
tion 3.1 This level of development raises questions about the ability of the ion's gas delivery system to meet this new demand without adverse sequences for existing natural gas customers.	This is in conflict with statements on the same page of the report that states "there is sufficient regional natural gas transmission and distribution capacity to serve core customers for the next 10-20 years". Also, additional customers and additional construction may result in rate decreases due to efficiencies and the margin available from new customers to pay for system improvements.
tion 3.1 A significant challenge will be resolving and managing the arate gas interests of two primary gas customer classes.	The interests are not disparate: both want reliable service at a reasonable cost. This is not a "significant challenge".
tion 3.1.2 The South Bay Power Plant is scheduled to be replaced by a state he art plant in 2009.	There is no set schedule. Duke's lease with the Port expires in 2009, however the lease does certain provisions regarding the plants RMR status.
ure 3-3 Power Plant usage forecast.	SDG&E has not produced a power plant forecast. SDG&E has at times provided examples, however, these were not forecasts of expected power plant usage.
le 3-1 Retail natural gas estimates.	SDG&E has not provided retail rate estimates. Source needs to be clarified.
le 3-2 Variability factors for LDC costs	These costs are all fully regulated thus market power is not a factor. References to market power need to be removed.
tion 3.3 This provides market power to that pipeline and puts the San Diego ion in a tenuous position with regard to its natural gas delivery options.	There is no market power. SoCalGas's operation of that pipe is regulated by the CPUC, there cannot be any "market power" since the rate is set based on cost based ratemaking. The region being in a "tenuous position" is an unsupported statement.

ion 3.4 SDG&E provided a forecast of EG throughput for Firm Service nand (FSD) planning.	SDG&E did not provide a forecast of EG throughput. In some regulatory filings SDG&E has illustrated the ability to serve certain load levels but did not provide a forecast. SDG&E has said that large EG customers should provide SDG&E with their forecasted need so that we could design and build a system to meet their needs.
ion 3.5 The entire section.	This entire section does not match the header. The description of the regulatory process is full of inaccuracies, and includes an extremely incomplete history. As an example, statements that "SDG&E has not had a GRC in nearly a decade (nor has SoCalGas for that matter)" are a meaningless statement since GRC were replaced with cost of service proceedings a decade ago. In a Cost of Service preceding, the Commission reviews SDG&E total operations, all costs and future additions, then sets rates to only recover just and reasonable costs.
ion 3-5 Historically, the question of who pays for expansion fell squarely he utility itself.	The costs of expansions have fallen squarely on the CPUC, which sets rates and determines which class of customers should pay for expansions.
ion 3.5 The Forum in which to review [proposals for facility additions] conducted was a General Rate Case	They are now addressed on Cost of Service Proceedings, which replaced General Rate Case over ten years ago.
ion 3.5 The state's gas utilities have not been willing to invest in non-core infrastructure.	Too broad of a statement. Up until very recently, additional investments were not needed, as the report points out. SoCalGas has always been willing to build for non-core with contractual commitments. SoCalGas seeks contractual commitments so that those who wanted the additions would pay for them, and not saddle other customers with costs. SDG&E did not need to invest for non-core since the investments made for the core provided substantial reliability. SDG&E made a proposal to the CPUC for system expansions. The CPUC voted out the results on November 21,2002.
ion 3.7.1 SoCalGas and SDG&E are in the midst of transitioning to a new ratemaking methodology.	SoCalGas and SDG&E are not in the midst of any change. If any change is proposed, it will be subject to substantial hearing, public input and only adopted if the CPUC adopts it as being in the public interest.
ion 3.7.2 Customer classes have not always seen eye to eye in basic tions of gas supply, transmission, distribution storage and of course pricing nese functions.	Customers do see eye-to-eye in wanting low-cost, reliable service. They do not compete for service. Representatives from each class always seem to want the other classes to pay all the costs, but that should not surprise anyone.
ion 3.7.3 The Final CPUC decision disallowed consolidation of the two folios.	The decision delayed a decision on the combination until other CPUC investigations were completed.

ion 3.7.4 Until this regulatory hurdle is overcome, gas supplies from xico will not be economically feasible for San Diego.	This is a false statement. The peaking tariff does not address gas supplies from Mexico. A peaking tariff would have no impact on gas supplies delivered at the border into the SDG&E system. The sponsor should provide a cost comparison between the cost of shipping gas on SoCalGas system and the Cost on Baja Norte. The sponsors also need to explain the limitations, such as take or pay provisions, and the lack of balancing and delivery flexibility on the Baja Norte system. Service on an interstate pipeline is not the same service as service on a local distribution system.
hapter 4 Electricity	
eral Comment	The study has not conducted transmission reliability or production cost modeling to show the impacts of their recommendations on the region. Thus comments about reliability are speculative. They have also not shown what costs impact the recommended resources would have. The report treats the contracts the State entered into on behalf of the customers as almost an after thought even though these will provide over 50% of the regions power for the next ten years.
ion 4.1.1 Extreme electricity price volatility is likely unless the region ues opportunities to buffer itself from the high market risks that exist.	CDWR contracts and SDG&E's generation and long-term power purchases currently in place cover substantially all of the regions energy needs for at least the next 10 years. These will substantially mitigate price volatility.
ion 4.1.1 There is concern on the part of California Planning officials in CAISO and the California Power Authority (CPA).	SDG&E has locked up a substantial portion of the power needs for years to come. This is just another instance where a generality is used to try to create a local issue that does not exist.
ion 4.1.1 New CAISO locational marginal pricing (LMP) transmission ing and capacity reserve requirements for regional grid reliability suggest the region is going to be more vulnerable to system constraints unless tional generation and transmission is added to the area.	The possible adoption of LMP or capacity reserve requirement is not going to make the region any more vulnerable than it is now. The same vulnerability will exist even if these are not adopted. That is why SDG&E has been working to get additional transmission added for the years.
ion 4.1.1 A number of needed transmission improvements are being made e region. Because of reliability concerns and the fact that the region has one major northern feeder into the region, it appears that some new tional transmission to the North is necessary. The line will be needed by 5, unless the region takes positive action soon to ensure new generation is lace by that time.	The authors should make it clear that they are supporting the Valley Rainbow interconnect, the only transmission to the north. Additional transmission to the south does not improve reliability. The authors also need to explain why this bullet, along with the discussion in this section of the report, is so supportive of the project but the executive summary and recommendations are not. This is a substantial inconsistency in the report.

ion 4.1.1 A broader regional energy infrastructure plan is needed. ently, the planning of infrastructure project initiatives is too fragmented. itionally, energy infrastructure planning should be a transparent process is more accessible to the public.	The authors need to explain this point. They need to provide specific examples and solutions. SDG&E's planning includes locking up power supply and expanding transmission to tap the available excess power that was developed outside the region. All of SDG&E planning is fully accessible to the public, subject to hearings before the CPUC, which are open to the public. Public hearings are often held on major projects.
tion 4.1.1 Load flow analysis is needed to evaluate the most optimal way to nce new transmission development and co-location of generation, not only supply purposes but also for regional grid reliability.	The authors need to explain what they mean by this. The region's transmission system is designed and rated based on optimal load flow analyses using standard industry techniques. Results are approved by the CAISO and the WECC, the group responsible for electric system reliability in the western states. SDG&E regularly meets with developers looking to locate power plants in the region to discuss the ability to interconnect to the electric grid. We also meet with them in advance regarding the ability to provide natural gas service and have provided studies for developers on the system ability to meet new load growth.
ion 4.1.1 An energy development authority needs to track demand and wable resources along with transmission as a basis of considering itional generation.	SDG&E questions the need for another agency to do more tracking. What is needed are accountable actions, not more agency tracking. Tracking does not get new infrastructure built. The report provides no support for what this will achieve.
tion 4.2.1 The decrease in consumption was the result of the impact of ner prices, consumer conservation behavior and other factors such as eased use of small-scale distributed generation.	The authors should make it clear how much of the decrease was a result of increased distributed generation.
tion 4.3.1 In light of this high degree of uncertainty, SDG&E is forced to n for grid reliability improvements based on a very conservative generation ansion assumptions because the utility must provide reliable service ardless of the uncertainty of the regulatory climate and capital markets for eration investment.	We find it hard to believe that this very sentence is not in the summary or executive summary. It shows that SDG&E is planning in light of all the uncertainty that the report highlights. SDG&E believes the regions energy needs are too critical to plan any other way.
tion 4.3.1 Must run units are more expensive to operate and are only used perating reserves during peak periods or in times of emergency backup.	Must run units are units that must remain in service due to transmission constraints and units that the CAISO may need to call on at time to balance loads. Must run units can and do operate in the market like all other units. The lack of transmission in the region has resulted in San Diego having a substantial number of must run units. The region's consumers pay the costs of keeping these units open and paying any increase in costs which result from having them operate out of economic order.

.tion 4.3.1 Historical resource planning criteria and that of the WECC ·imes a one-in-ten chance that one or two of the most significant plants will be available or a transmission outage in the region may occur.	This is not a historical or current planning criterion. Generation supply reliability can only be done through production cost modeling. Transmission reliability needs to be done based on optimal load flows, which was also not completed. The CAISO grid reliability criterion requires the system be able to serve a load even after the loss of the single largest transmission line and the single largest generator. The load forecast used for this analysis is based on a forecasted load that has only a 10% probability of being exceeded.
·ion 4.3.1 An estimated 300 MWs of older combustion turbine units are ımated to be removed from the region by 2003 because these plants are old, ·ficient, and beyond their useful economic life.	About 67 MW of units will be removed because the owner's property lease with the Navy expired and they were unsuccessful in negotiating a new lease. All of the others are RMR units. Being a RMR unit says that the units are needed for reliability and thus cannot be shut down and removed without ISO approval.
tion 4.3.1 The Port of San Diego has made a commitment to replace South ·· with a new plant by 2009.	The sponsors should explain what commitment the Port has made. Does this mean the Port will finance and build the plant?
ıion 4.3.1 After this time, SONGS will need to recover its costs in the ıket.	The CPUC has already ordered that SONGs will return to the utility rate base as of January 1, 2004.
tion 4.3.2 The Palo Verde region is going to be a large hub of new ·eration as is North Baja.	Palo Verde is a recognized trading point with tens of thousands of megawatts of generation in excess of local load and substantial transmission capability in numerous directions. North Baja has limited generation, most of which is dedicated to local load. Transmission is limited. North Baja is not presently a hub and will not be one in the foreseeable future. These two locations are not comparable.
·ble 4-2 San Diego has the most expensive natural gas in the WSCC.	The sponsors need to explain the comment about high transportation costs. Table 3-2 shows the cost to transport gas from the border is only $0.20 of a $3.00 total cost, a small portion.
tion 4.3.1 The Cabrillo Plant (Encina) ... it is anticipated that both units ı be shut down by the end of the decade.	Only if it is economic to do so and other units have been built to replace them. Both of these units are RMR units, which cannot be shut down.
·tion 4.5.2.2 The addition of Otay Mesa by itself could have the effect of ·erring Valley Rainbow for several years.	This is true only if all remaining generation in the region stays in service. An assumption this report does not agree with.

tion 4.5.2.2 There are many problems with the current approach to smission planning in the region: 1. It is reactive and does not take into account longer-term power plant co-location needs to improve transmission infrastructure requirements. 2. Options are screened based on traditional planning approaches and technology. 3. Few options are usually considered for major investments (e.g., Valley Rainbow project) 4. The role of balancing load flow and demand management is seldom considered, including more dynamic pricing—there is too much friction in the current system of balancing supply, demand and pricing.	This statement is false and unsupported. 1. Transmission plans are prepared every year with at least a five-year outlook. They are designed to move generation to load. To some extent, they do react to new generation since plans are designed to move generation to load. 2. The sponsors need to provide a specific example of what they believe should be done. Plans are done using state-of–the-art modeling and planning techniques and are done based on industry-wide standards. 3. Multiple options are considered to find the lowest cost path. In the Valley Rainbow case, numerous paths and locations were analyzed. 4. Transmission plans are designed to serve the load. The sponsor needs to define "friction."
hapter 5 Demand-Side Options	
eral Comment	A considerable amount of attention is focused on distributed generation. There was very little discussion on energy efficiency (E/E). This appears to be unbalanced since E/E results in permanent load reduction and it is more cost effective than DG. More information should also be included for Demand Response (DR), but it should recognize that DR has limited potential, as a temporary solution for a limited number of peak hours during the year.
tion 5.1.3 Short-Term.	The California Energy Commission is responsible for setting building standards. The region should partner with the CEC to evaluate building standards to incorporate higher efficiency equipment.
tion 5.2.3 This study projects that a total of 2,200 to 3,200 MWs of DG and wable capacity could be installed by 2030.	This assumes a 6%-7.4% annual growth rate over the next 28 years, assuming the 372.3 MW combined current capacity quoted in paragraph 2. This has to be highly speculative given the long-term uncertainties of energy prices, environmental regulations, and regulatory priorities.
le 5-2 Program Life Cycle Cost.	"Program Life Cycle Cost, cents/kWh (probably should be $/kWh not cents/kWh). This is an inconsistency with the following two bullets in Section 5.3.1.
tion 5.3.1, Bullet 3 "Residential and commercial photovoltaic and C&I fits provide the greatest savings (1,401 GWh) at a relatively low cost 26 /kWh)."	Are the sponsors saying that $0.26/kWh is a relative low energy cost? The report needs to explain how this is a relatively low cost.

ıion 5.3.1, Bullet 3 "Residential and commercial photovoltaic and C&I ›fits provide the greatest savings (1,401 GWh) at a relatively low cost 26 /kWh)."	All cost effectiveness measures should be based on marginal cost, not average cost.
›le 5-7 Estimated Remaining CHP Potential in the C&I Market, San Diego, ws over half (54%) of the potential is from Industrial Customers. Section 1.2 (below Table 5-7) states "in the industrial sector, the applications are ›centrated in the petroleum, food processing, pulp and paper, and wood ›essing industries.	San Diego has none of these industries, except some small food processors. This Industrial potential is highly speculative at best, and probably significantly overstated.
›tion 5.5.1.2 (below Table 5-7) continues..."In the commercial sector, the ›lications are concentrated in data centers, telecommunications, high tech ›lications, pharmaceuticals, biotechnology, education, restaurants, lodging, l apartment buildings."	These CHP potentials appear to be an extrapolation of California estimates by the CEC. It does not consider the unique industrial makeup of San Diego and could be grossly overstated for the region.
›tion 5.5.4 (Photovoltaic), Third Paragraph: there appears to be a typo in the ›nd line "from 11 in 2001 (29 kW) to _____ in 2001 (836 kW).	We assume the first reference to 2001 should be some previous year
›tion 5.5.4 The report states "...and several projects in the 750-kW to 1-MW ›ge will be installed within a year's timeframe."	In the following paragraph's last line, the report states "...and several projects in the 750-kW to 1-MW range will be installed within a year's timeframe." At this time, one is installed, and one is in the feasibility study stage, and there are no additional projects of this size known to SDG&E at this time. Given the time necessary to apply for permits and interconnection procedures, if a project is not known at this time, it could probably not be installed "within a year's timeframe."
›tion 5.5.4.1 The report suggests that 10% of new homes could include PV ›ems to add up to 36 MW of capacity to the region by 2010. Currently state limits net metering capacity to .5% of SDG&E peak load, or ›roximately 20 MW. Without the benefit of net metering, it is unlikely that ›omers will purchase PV systems.	There is no supporting evidence in the report to substantiate whether the 10% of projected new homes installed with PV is a realistic number. The report should state what percent of the total homebuyers in the Shea Homes Scripps Highland community elected to include the PV system and take advantage of the tax credits. Lastly, the claim that the Shea Homes Scripps Highlands community "had positive cash flow after 10 years" cannot be true yet, since these installations have all occurred within the past two years. Any claims of positive cash flow from these installations must assume projections of future energy costs, which are not substantiated in this report anywhere.

ion 5.7 Renewable availability – up to 500 MW of wind, substantial PV...	Report states that source for the wind information is "confidential" and was received from potential developers. Nothing about the cost of the "substantial PV" – about $10,000 per kw. The CEC in its Renewable Energy Report dated November 2001 found that "Thus, at this time, interest in renewable energy systems is quite low among both homeowners and business/commercial property decision-makers." And " The primary reason given for not being interested in a renewable energy system was cost concerns." The numbers look very ambitious, no load flow studies have been done to support transmission line construction to connect additional wind facilities to the grid. Since wind facilities are likely to be built in remote locations, the cost and environmental impact of new transmission construction could be prohibitive.
le 5-10:	The numbers in the table do not match the statements made in various sections of the report. Additionally, the data in this table does not reflect any adjustments for risks, uncertainties in technologies, policies, etc. which are reflected in the report body in various sections • PV: the table shows cumulative 2030 potential for PV from 175 MW for the low scenario, to 275 MW for the high scenario. In report Section 5.4.4.2 Summary: Photovoltaic, page 5-18, and the report states that PV could represent between 230 and 800 MW of capability over the next 30 years. • Wind: The data in the table for Wind shows 600 to 800 MW, which is extremely inconsistent with Section 5.7.2 Summary: Wind, where numbers are quoted from 40 to 160 MW. • Geothermal: The table shows cumulative 2030 potential for Geothermal from 80 to 300 MW, and the corresponding section on Geothermal, Section 5.9.2, page 5-22 states the potential is 15 to 400 MW. • Landfill: The table shows cumulative 2030 potential at 80 MW, and the report states the potential is "up to 100 MW" (Section 5.5.2.2, page 5-16) • Fuel Cells: This is the only part of the table where the data matches the report text, showing a potential of 15 to 70 MW in both places.

tion 5.13 Avoidefer infrastructure investments.	There is nothing in the report to substantiate any T&D benefits. Without DG being installed at the right place, in the right size, at the right time and with physical assurance. There can be no possible benefit for the T&D utility. These four criteria are key to modifying the planning, designing, building and operating cycle that drives our capital expenditures and O&M dollars. If the system is designed based on the DG system, the sponsors need to be clear as to what customer will not be served when the DG system is not operating.
tion 5.14 For ssectors of the economy, like retail, energy is the single [illegible] reduction can have a	This "single largest expense" statement is not supported or attributed to a [illegible] professional services, and cost of goods sold to name a few other large expenses. This assertion has no facts or evidence to support.
tnote 52 Estimf cool roofs is 25 million sq. ft. but not all in SD nty.	To be consistent, the report should extrapolate how much of this number is applicable to SD County. Since SDREO administers this program, they should have this data.
tion 5.16.7 Tar	The AV1 tariff was closed effective 10/01/02, and was replaced by AL-TOU-CP. AV-2, AV-3, RTP-1 and RTP-2 no longer exist (since January 2002). Terms and conditions of AL-TOU-CP are slightly different than AV-1. This section needs to be updated.
tion 6 Opti and Scenarios	
erat Comment	The scenarios are based on numerous assumptions regarding future development and technological breakthroughs. Thus each scenario has very different risks and reliability impacts. Since these scenarios were not modeled, impact on the region can not be determined Many technologies, such as wind which is available at only a portion of its full capacity at time of system peak, are shown at the full capacity value in the table.
ion 6.1.1 Thenty is now served by two major power plants for South and Cabrillo,rh are older units and will be retired by 2009	Both Plants are RMR units and cannot be closed without replacements.
ion 6.1.1 Signnt investment in energy efficiency and DG-renewables d help alleviaiear term tight supply/demand balance.	There is not a tight supply/demand balance in the near term. There could be a reliability issue in the near term without new transmission to the north.
ables	All tables ignore the nearly 2,700 MW of power the CDWR purchased that has been assigned to San Diego customers.

APPENDIX G	
	• Page G-2: "COMPASS uses marginal rate (tail block) to compute bills and savings." This methodology needs to be explained. Block rates do not apply to SDG&E's commercial rates and may over-estimate residential bills and savings since the high baseline allowance places few customers and kWhs within the highest "tail" block. • Page G-4: No Gas Avoided Costs #s. • Page G-6: Table G-4 variable per unit program costs section excluding low. This table requires additional explanation. • Page G-7, Table G-6: The Marginal Electric Costs and Marginal Gas Costs used in the Low, Medium, and High Case Scenarios are briefly described but not provided. It is hard to judge reasonableness without the assumptions provided in detail. The Table indicates that gas costs assumptions are the same for the Low, Medium, and High Case Scenarios. One would assume that gas costs should follow electric costs to some extent, since gas is generally the marginal generation fuel. • Table G-7: This Comparison of CHP Technologies appears to include Diesel Engines fueled by Diesel and Residual fuels as a viable CHP technology in San Diego. San Diego ACPD permit restrictions would probably exclude this technology alterative from consideration. Table G-8: The units in the table appear to be in $/kWh not (Cents/kWh) as it appears in the title. Furthermore the T&D Competitive Retail Economics for Peaking Load appears to be off by an order of magnitude of 100. Thus, the Total Economics for Peaking Load appears to be incorrect. Lastly, Table G-8 appears to be flawed since busbar economics for large versus small units have identical numbers, but it is difficult to tell since it is not clear what these numbers are or how they were derived.