DRA

DIVISION OF RATEPAYER ADVOCATES

2011 Annual Report

Submitted to the Legislature
January 10, 2012

DRA's Statutory Mission

To obtain the lowest possible rates for service consistent with reliable and safe service levels. In fulfilling this goal, DRA also advocates for customer and environmental protections.

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with contributions by Charmian Desales

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Division of Ratepayer Advocates
California Public Utilities Commission

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Honorable Jerry Brown, Governor of the state of California, and distinguished members of the California State Legislature:

I am pleased to present to you the Annual Report of the Division of Ratepayer Advocates (DRA) of the California Public Utilities Commission. This Annual Report highlights the major accomplishments and activities of DRA in 2011 and offers our insight, from a consumer advocate's prospective, of the challenges and issues facing California's utility ratepayers in the coming year.

This Annual Report also fulfills DRA's legislative requirement[1] to provide the following information:

1. The number of personnel years assigned to DRA and a comparison of the staffing levels for a five-year period.
2. The total dollars expended by DRA in the prior year, estimated total dollars expended in the current year, and the total dollars proposed for appropriation in the following budget year.
3. Workload standards and measures for DRA.

DRA's statutory directive under Public Utilities Code Section 309.5 is to represent and advocate on behalf of the interests of public utility customers and to try to obtain the "lowest possible rate for service consistent with reliable and safe service levels." As the only state entity charged with this responsibility, DRA plays a critical role in ensuring that public utility customers are represented before the California Public Utilities Commission (CPUC) and in other forums that affect how much customers pay for utility services and the reliability and quality of those services. In the evolving landscape of California's energy, water, and telecommunications policies, DRA also sees its role as an important partner in helping to shape state policies that affect utility customers and the environment.

DRA is a very cost effective organization that has saved utility ratepayers at least $157 for every dollar spent by DRA. That savings has occurred in many different areas as highlighted in the Annual Report. The utilities' General Rate Cases (GRCs) continue to be a central area of focus for DRA because it is through a GRC application that the utilities obtain the CPUC's approval for most programs and customer charges. Also important in 2011 were the areas of California's Cap and Trade program for reducing greenhouse gases in the energy sector, energy efficiency, smart grid, and time varied rates for residential and small business customers.

[1] Public Utilities Code Sections 309.5 (g).

In the area of energy policy, DRA has been a critical consumer advocate in finding ways for the state to meet its goals to reduce greenhouse gases, to increase energy efficiency, to keep the energy system reliable and to increase renewable energy. It is important to meet these goals in ways that do not unnecessarily burden utility customers, especially low income customers. Basic utility service must also remain affordable. The state mandate to increase electricity generation from renewable resources has served to steer decision-makers to approve and facilitate more central plant and distributed generation resources than at any time in California's history. DRA enthusiastically supports the goal of increasing renewable resources in California and sees its role as advising decision-makers on the best way to achieve that goal. To complement our advocacy work at the CPUC, DRA has published several research reports on specific issues that affect consumers' pocketbooks as we seek to lessen our environmental footprint. These include:

- *Green Rush: IOU's Compliance with RPS*
- *California's Solar PV Paradox: Declining CSI Prices and Rising IOU Bid Prices*
- *Status of Energy Utility Service Disconnections in California*
- *Time Variant Pricing for California's Small Electric Consumers*

The natural gas explosion in San Bruno, and the revelations that recordkeeping and inspection routines of the gas utilities in California were severely lacking, has caused DRA to examine its role in obtaining utility compliance with safety rules. Certifying that natural gas systems are operated in a safe manner is the responsibility of state and federal safety officials and is an area outside of the primary mission of DRA, which has the tools to examine utility costs. However, DRA's legislative mandate is to advocate for service that is safe and reliable, as well as affordable. It is fundamental that utility service must be safe, and it is also our position that customers have been paying utilities for many years for a level of safety that should be the best in the world. We have come to understand that although the gas utilities are fully reimbursed by customers for building, operating, and maintaining their gas transmission and distribution network, we cannot assume that those systems are safe. DRA has therefore expanded its focus on the gas utilities' safety-related programs. Specifically, DRA is reviewing the utilities' safety proposals to ensure that they actually result in safe operations and that the billions of dollars of costs the utilities claim are necessary to implement these programs are justified and reasonable. DRA fully expects that utility shareholders will bear the vast majority of cost responsibility to rejuvenate the natural gas delivery systems to a level that customers have been supporting for decades. DRA will continue to play an active role to promote necessary changes to the way the gas utilities operate and to the way the CPUC administers its oversight responsibility.

In the area of water policy, DRA has advocated for cost-effective water conservation and encouraged associated energy savings measures. DRA has also sought the best water supply solutions to address long-term water supply needs, while recommending ways to keep rates affordable. At this time of lower returns on investments for all businesses, DRA has fought to ensure that privately held water companies are not reaping higher than necessary profits from their water customers.

In the field of communications, DRA looks to keep services for low income telephone customers affordable and reliable. DRA promoted improvements to the LifeLine program which would provide greater choices for all customers with the addition of a wireless option. DRA also opposed AT&T's attempt to merge with T-Mobile and reduce competition in telecommunication services. Competition is critical because it is the best tool we have to keep down telecommunication costs, now that regulatory oversight of those costs has been virtually eliminated. Additionally, DRA promoted improved guidelines and criteria for the California Advanced Services Fund (CASF) program in order to promote adoption of broadband in unserved and under-served regions of California.

DRA also plays an active role outside of the CPUC. Most importantly, DRA provides informational briefings as requested by members of the state Legislature and the Governor's office. DRA has been an active participant in proceedings at the California Energy Commission and the California Independent System Operator. DRA also provides consumer representation in other forums related to CPUC proceedings such as at the low-income oversight boards, telecommunications public policy committees, and the National Association of State Utility Consumer Advocates (NASUCA).

I am proud of the work of our dedicated and talented staff of accountants, economists, engineers, business people, and attorneys. DRA will continue to be an important resource for decision-makers and an effective advocate for utility customers.

Joseph P. Como
Acting Director

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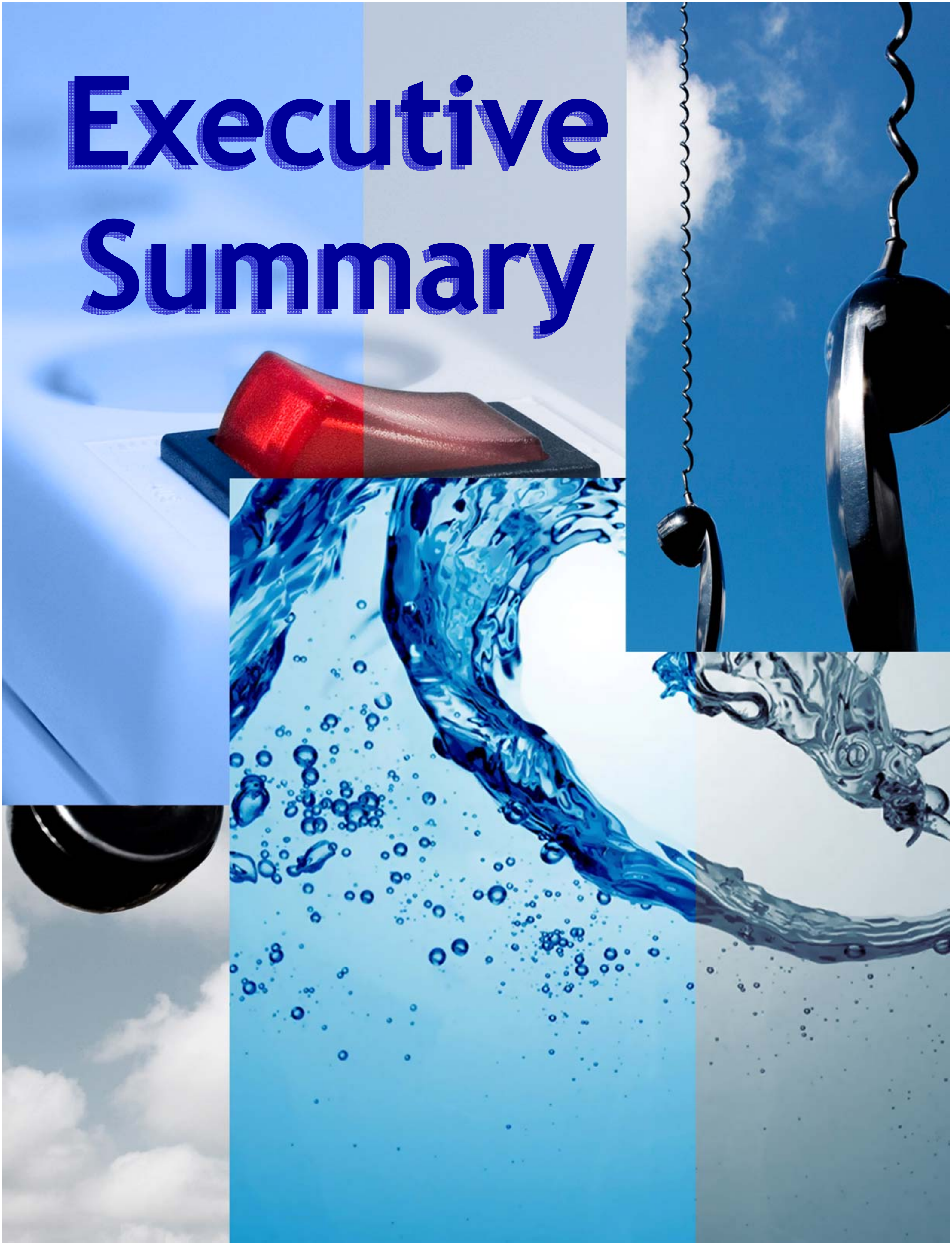


The **Division of Ratepayer Advocates (DRA)** is an independent consumer advocate within the California Public Utilities Commission (CPUC) that advocates solely on behalf of investor owned utility ratepayers. As the only state entity charged with this responsibility, DRA plays a critical role in ensuring that the customers of California's energy, water, and telecommunications utilities are represented at the CPUC and in other forums that affect how much consumers will pay for utility services and the reliability and safety of those services.

DRA's staff of experts performs detailed review and analyses on regulatory policy issues and utility requests, that total in the tens of billions of dollars, to determine whether they are in the interest of the ratepayers who fund utility activities through their utility bills. Additionally, DRA supports environmental protections and seeks to ensure that utility actions comport with CPUC rules and California environmental laws. DRA actively participates in CPUC proceedings to aid the Commission in developing the record from which it will formulate its final decisions. DRA also actively lobbies decision-makers on behalf of ratepayers to ensure that the consumer perspective is heard.

DRA's Staff and Budget

DRA has a staff of 142 professionals consisting of engineers, economists, scientists, and auditors with expertise in regulatory issues related to the electricity, natural gas, water, and telecommunications industries in California.

DRA's budget for 2011 was $27,283,000. DRA's expenditures in 2011 represented a small fraction of ratepayer investment compared with the more than $4.1 billion in savings DRA achieved for Californians in the form of lower utility rates and avoided rate increases. For every customer dollar spent on DRA in 2011, they saved approximately $157 across their utility bills.

DRA's Work in 2011

DRA aided in shaping the outcome of numerous CPUC decisions and California legislation that will impact ratepayers.

Who We Are

Division of Ratepayer Advocates (DRA): In 1984, the CPUC created DRA, formerly known as the "Public Staff Division," in a reorganization plan to more efficiently use staff resources. In 1996, SB 960 (Chapter 856, Statutes of 1996) renamed the Division the "Office of Ratepayer Advocates" (ORA), and while keeping the ratepayer advocacy function within the CPUC for mutually beneficial purposes, made it independent with respect to policy, advocacy, and budget. SB 960 made the DRA Director a gubernatorial appointee subject to Senate confirmation. In 1997, the CPUC implemented its reorganization plan, "Vision 2000," which significantly diminished the staff of ORA, but the ratepayer advocacy responsibilities and workload remained the same. In 2005, SB 608 (Chapter 440, Statues of 2005) renamed ORA as DRA – the Division of Ratepayer Advocates - and strengthened the division by providing it with autonomy over its budget and staffing resources and authorizing the appointment of a full-time Chief Counsel.

Energy

DRA represents the customers of California's investor owned energy utilities, most notably Pacific Gas and Electric Company (PG&E), Southern California Edison (Edison), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E). These utilities serve approximately 80 percent of all California's energy customers. DRA evaluates energy regulatory issues for both electricity and natural gas in the areas of Customer Rates, Procurement, Renewables, Transmission, Demand-side Management, and Consumer Protection. DRA's advocacy efforts in 2011 saved ratepayers more than $4 billion in energy costs.

DRA's energy advocacy efforts focused on achieving California's progressive energy goals in the most affordable manner for residential and small business customers. DRA worked on four large rate cases in 2011, reviewing utility requests for revenue increases and programs that totaled more than $20 billion statewide, and saved PG&E customers nearly $2.5 billion. DRA opposed the CPUC's Critical Peak Pricing rate scheme for PG&E's small business customers, who may be the least equipped to deal with the complex mechanism.

DRA supports California's climate change goals and the role of renewable energy to aid in meeting those goals at competitive market rates. However, DRA opposed the approval of the most overpriced renewables contracts, given that the utilities are on-track to meet their Renewable Portfolio Standard (RPS) goals. DRA persuaded the CPUC to reject two utility owned wind power projects resulting in savings of more than a billion dollars. DRA advocates for programs and policies that support California's goal to reduce greenhouse gases.

On the consumer protection side, DRA was successful in achieving many strong Smart Grid privacy rules that limit access to personally identifiable information and energy usage data. Additionally, DRA was effective in achieving additional time for stakeholders to improve low-income assistance programs that can have a larger impact on the Affordability Gap that exists for the most at-risk customers. Subsequent to DRA's 2011 Report on the Status of Energy Service Disconnections, the CPUC continued disconnection protections for PG&E and Edison customers. And in the wake of the 2010 San Bruno natural gas pipeline explosion, DRA augmented its natural gas staff in order to provide increased scrutiny of utility requests and expenditures to ensure that customers receive the lowest possible rates for safe service.

Details of DRA's 2011 energy activities can be found in the Energy Chapter, starting on page 16.

Water

DRA represents 1.3 million customers of investor owned Class A water utilities (more than 10,000 service connections) & Class B water utilities (less than 10,000 service connections, but more than 5,000). The CPUC has regulatory jurisdiction over approximately 20 percent of all of California's urban water usage customers. DRA scrutinizes water utility requests for additional revenues that will increase customer bills. DRA advocates on behalf of water ratepayers in CPUC proceedings and participates in statewide planning processes at the Department of Water Resources and the California Air Resources Board. In 2011, DRA's efforts saved water customers over $23.3 million, resulting in an averaging monthly savings of $7.08 per customer.

DRA's efforts on Water issues are two-fold: 1) Review and analysis of water utility General Rate Cases (GRCs), which determine the amount of revenues a water utility may collect that in turn will impact a customer's bill; and 2) Development of water policy which sets rules and develops programs that shape the water industry.

In 2011, DRA had many successes including negotiating a settlement with Class A water companies that would lower the return on equity from 10.2% to 9.99%. DRA worked on 5 rate cases in 2011 that saved a total of $23.3 million from utilities' total revenue increase request of $70.2 million. DRA's advocacy on the removal of the San Clemente Dam project resulted in a proposed decision with numerous consumer protections, including capping project costs. Additionally, Water Conservation efforts resulted in progress with focus on Water Recycling and other conservation programs.

Details of DRA's 2011 water activities can be found in the Water Chapter, starting on page 66.

Communications Policy

DRA represents customers of both wireline and wireless telephone carriers on Communications policy issues with particular focus on affordability, consumer protection, and service quality. DRA also works to ensure that all customers have equal access to broadband services at reasonable costs.

California's telecommunications network is central to the daily life, work, safety and education of people throughout the state. DRA represents all customers of telephone carriers, seeking to improve service quality and reliability, hasten response times by operators and repair personnel, maintain rates at reasonable levels, increase coverage and reliability for 911 and emergency services, and protect consumers from fraud, unauthorized charges, and abusive marketing practices. DRA also actively participates in the promotion and development of federal and state programs to expand broadband access across California at reasonable costs.

In 2011, DRA sought to protect customer dollars by targeting inefficiency and improving the success of ratepayer-funded programs. DRA promoted improved guidelines and stricter accountability and outreach requirements for the California Advanced Services Fund (CASF) program, to promote and speed the adoption of broadband in unserved and under-served regions of California. DRA also urged the Commission to open an investigation and to oppose AT&T's federal merger application, because the resulting concentration in the wireless market would have increased costs substantially for all Californians. DRA continues to fight for improvements in the LifeLine program, seeking to offer state subsidization of wireless and VoIP services as an option for low-income customers, and to streamline the application process for eligible beneficiaries.

Details of DRA's 2011 communications activities can be found in the Communications Policy Chapter, starting on page 80.

DRA's Annual Report

In addition to DRA's 2011 activities, this Report includes history, background, and definitions in order to provide context to understanding DRA's regulatory and advocacy activities. Terms in bold are further elaborated on in the blue side bars.

DRA's Annual Report can be found on DRA's website at:
http://www.dra.ca.gov/DRA/about/annualreports.htm

Report to the Legislature

On or before January 10 of each year, the Division of Ratepayer Advocates (DRA) is required to provide to the Legislature:[2]

- The number of personnel years assigned to DRA and a comparison of the staffing levels for a five-year period.
- The total dollars expended by DRA in the prior year, estimated total dollars expended in the current year, and the total dollars proposed for appropriation in the following budget year.
- Workload standards and measures for DRA.

Description of DRA Staffing

DRA currently has 142 authorized positions.[3] At its peak, DRA was comprised of eleven branches with over 200 employees. The table below provides a comparison of current staffing levels with those over the past five years.

DRA Staffing Levels for a 5 Year Period

Fiscal Year	Total DRA Staff	Explanation
2008 / 2009	138	4 positions added to Water branch and 1 position added to Electricity Policy and Planning branch for Greenhouse Gas issues
2009/ 2010	140	2 positions added to Electricity Policy and Planning branch for Transmission issues
2010 / 2011	142	2 positions added to Electricity Pricing and Customer Programs Branch for Energy Efficiency and Low-Income Issues
2011 / 2012	142	2 positions were redirected to cover Natural Gas policy issues

DRA is led by an executive management team, which oversees DRA's five branches covering the issues of energy, water, and communications. Dana Appling was the director of DRA until August of 2010. She had served as DRA's director since 2004. DRA is served by an acting director pending a decision of the governor on a permanent appointment.

Acting Director, Joe Como: Joe Como has served as DRA's acting director since August 2010. The acting director manages the activities of three Energy branches, the Water branch, and the Communications Policy branch.

Acting Deputy Director/Energy, Linda Serizawa: Linda Serizawa oversees the activities of DRA's three Energy branches: Energy Cost of Service Branch, which works on ratemaking activities including Natural Gas; Electricity Policy and Planning Branch, which focuses on electric procurement, transmission, and climate change activities, including renewables; and the Electricity Pricing and Customer Programs Branch, which works on rate design, demand-side management programs, and low income assistance programs.

[2] This report is submitted in compliance with Section 309.5 (f) and (g) of the Public Utilities Code.
[3] Except for the Chief Counsel position which was authorized by Senate Bill 608, the CPUC Legal Division assigns attorneys to support DRA's staff in litigation matters. These attorneys are provided to DRA by the CPUC's legal division at a cost to DRA, but are not DRA staff. The cost for legal resources is included in DRA's budget.

Deputy Director/Water, Communications, and Governmental Affairs, Matthew Marcus: Matthew Marcus oversees the activities of DRA's Water and Communications Policy branches. The Water Branch works on general rate cases and water policy. The Communications Policy Branch works on telecommunications and broadband issues related to customer protection, service quality, and small carrier rate cases. Matthew is also responsible for DRA's activities in Sacramento and leads DRA's legislative lobbying and educational efforts, as well as responding to inquiries from Assembly and Senate offices and the office of the governor.

Policy Advisor, Cheryl Cox: Cheryl Cox is responsible for leading DRA's lobbying and public outreach efforts. She coordinates DRA's efforts to educate and persuade policymakers on ratepayer issues for energy, water, and telecommunications. Cheryl works to educate the public through the media and working collaboratively with community stakeholders.

Acting Chief Counsel, Karen Paull: Karen Paull is responsible for overseeing all of DRA's legal issues and managing attorneys as assigned by the CPUC, pursuant to SB 608.

DRA'S142 authorized staff positions, including 15 management and administrative positions, are allocated across the five DRA branches in the areas of Energy, Water, and Communications Policy managed by its program managers:

- **Energy Branches** (79 Staff)**:**
  - **Energy Cost of Service (ECOS),** Mark Pocta
  - **Electricity Planning and Policy (EPP),** Cynthia Walker
  - **Electricity Pricing and Customer Programs (EPCP),** Chris Danforth
- **Water Branch** (37 Staff)**,** Danilo Sanchez
- **Communications Policy Branch** (11 Staff)**,** Denise Mann

DRA's staff consists of technical, policy, and financial analysts with professional backgrounds as engineers, auditors, and economists with expertise in the regulatory issues of electricity, natural gas, water, and telecommunications. DRA's staff has increased by 4 positions since 2008-2009 reflecting the increase in new work in energy and water policy as California has strengthened its commitment to climate change goals, although it has remained flat over the past two years despite the number of proceedings it covers has slightly increased. While DRA's number of staff positions remains unchanged from the previous year, two positions were reallocated to natural gas proceedings, reflecting the state's efforts to strengthen its oversight on natural gas safety issues.

DRA' s Budget

Each year DRA reports to the Legislature the total dollars expended by DRA in previous years, estimated total dollars expended in the current year, and the total dollars proposed for appropriation in the upcoming budget year.

DRA's Budgets over the Past Five Fiscal Years

Fiscal Year	Total Direct Dollars Including Reimbursable Contracts[4]	Total Direct Dollars Plus Legal and Administrative Support
2008/2009	$19,904,850	$26,778,000
2009/2010	$20,432,000	$27,673,000
2010/2011	$21,313,500	$28,554,205
2011/2012	$20,564,000	$27,283,000
2012 / 2013	$20,564,000	$27,283,000

DRA develops its budget internally and then works with the CPUC to ensure DRA has sufficient resources, including assignment of attorneys and other legal support for the effective representation of consumer interests.[5] DRA's budget is statutorily designated as a separate account into which monies are annually transferred via the annual Budget Act to the CPUC Ratepayer Advocate Account, to be used exclusively by DRA in the performance of its duties. DRA's proposed $27.3 million budget for fiscal year 2012/2013 is unchanged from the previous year and includes staffing, legal services, and administrative overhead.

DRA Workload Standards and Measures

DRA measures its workload in three ways:

- The number of proceedings[6] in which DRA participates.
- The number of pleadings[7] filed by DRA with the CPUC.
- The number of outreach and education contacts.

DRA's Proceeding Work:

In 2011, DRA participated in 211 formal CPUC proceedings. These numbers do not reflect the greater complexity of the issues being addressed by DRA in omnibus proceedings addressing greenhouse gas emissions, renewable resource development, procurement and transmission working groups, water conservation, and other major initiatives. DRA is often the only voice representing consumer interests in a number of these proceedings. Since the CPUC relies on a formal evidentiary record in rendering its decisions, DRA's participation is essential to ensure that the CPUC has a record that reflects the interests of California's consumers.

[4] The DRA annual budget includes an authorization for "reimbursable contracts," the costs for which DRA is reimbursed by the relevant utilities. For FY2012/2013, the proposed amount is $4,035,000. Actual expenditures for reimbursable contracts occur only if there are proceedings that allow for reimbursable contracts. Examples include audits, mergers, and major resource additions, such as the construction of a transmission facility for which DRA may need to contract expert consultant services to assist DRA in analyzing the utility request or application.

[5] Public Utilities Code Section 309.5 (c): "The director shall develop a budget for the division which shall be subject to final approval of the commission. In accordance with the approved budget, the commission shall, by rule or order, provide for the assignment of personnel to, and the functioning of, the division. The division may employ experts necessary to carry out its functions. Personnel and resources, including attorneys and other legal support, shall be provided to the division at a level sufficient to ensure that customer and subscriber interests are effectively represented in all significant proceedings."

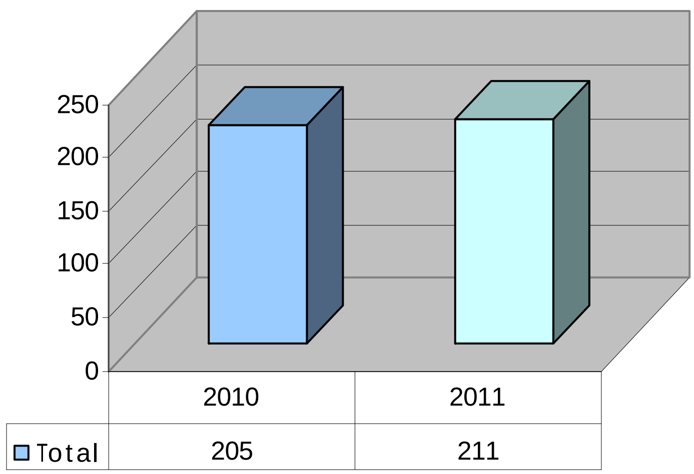
[6] A Proceeding is a formal case before the CPUC in which a legal record is developed. It may include an evidentiary hearing with the opportunity to cross-examine witnesses.

[7] A Pleading is a legal document filed in a formal proceeding before the CPUC. The CPUC conducts proceedings regarding a wide variety of matters such as applications to raise rates, CPUC investigations, CPUC rulemakings, or complaint cases. In a typical proceeding, pleadings filed by DRA might include a protest to a utility application, a motion for evidentiary hearings, opening and reply briefs, and opening and reply comments on a proposed decision, CPUC rulemaking, or CPUC investigation.

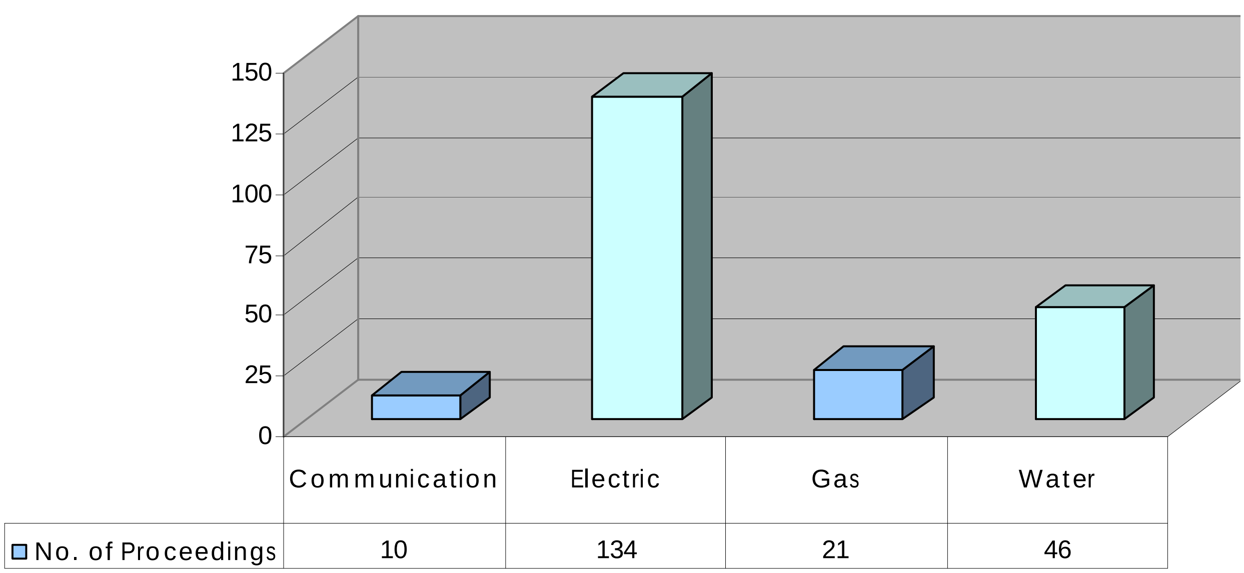
The 211 proceedings DRA worked on in 2011 reflect an increase in DRA's proceeding workload by approximately 2.8% from 2010. The following charts represent the total number of formal CPUC proceedings in which DRA participated in 2011 in comparison to 2010 proceeding participation, as well as broken out by industry group.

The number of Proceedings that DRA worked on = 211

Number of DRA Proceeding Work: 2010 vs. 2011



Number of DRA Proceeding Work by Industry

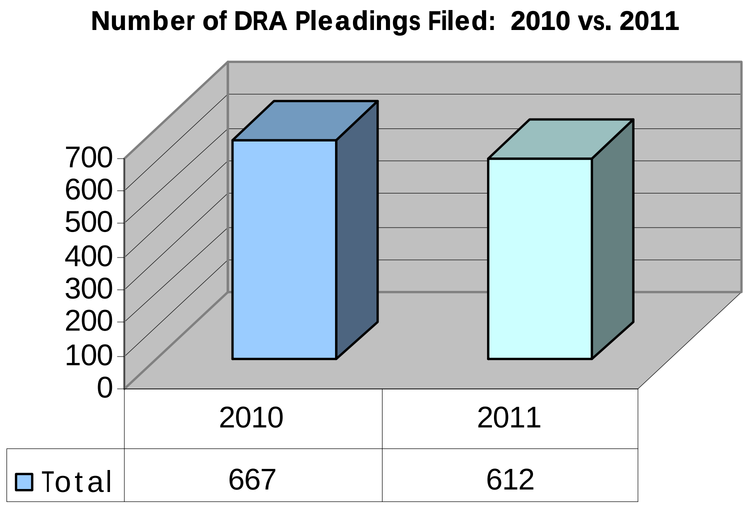


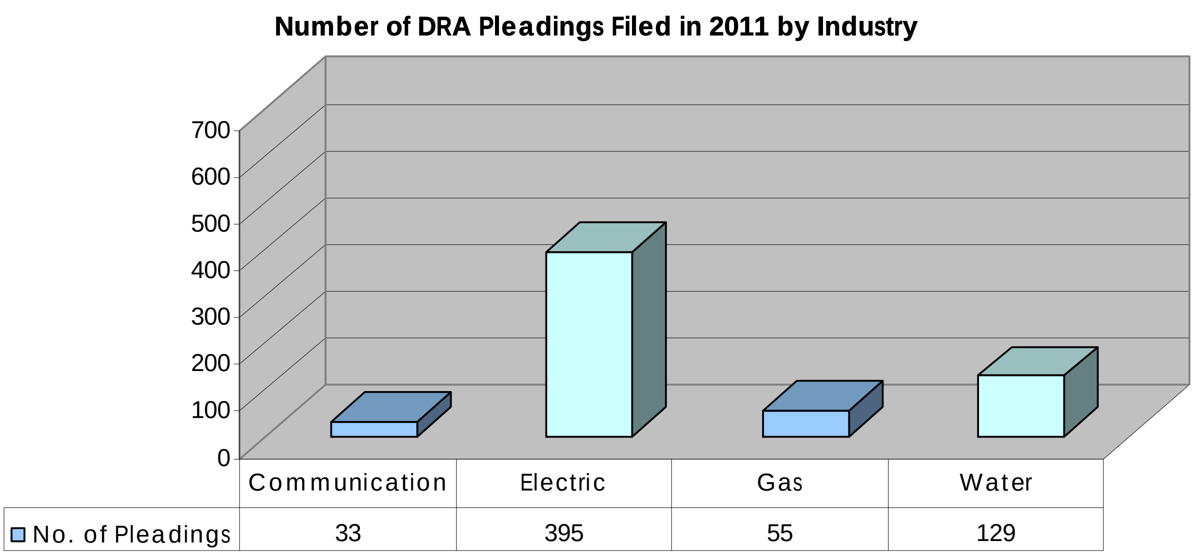
DRA's Pleading Work:

DRA staff and attorneys file hundreds of pleadings annually on behalf of customers covering issues related to electricity, natural gas, water, and communications. In 2011, DRA filed 612 pleadings in formal CPUC proceedings - a slight decrease in its pleadings from 2010.

The following charts represent the comparison of the number of pleadings DRA filed in 2011 and 2010, in total and by industry group, respectively.

The number of Pleadings DRA filed in 2010 = 612





Additionally, DRA participates in numerous informal proceedings before the CPUC in which utilities often seek authority via an advice letter.[8]

Beyond its participation in formal and informal CPUC proceedings, DRA is an active participant in proceedings at the California Energy Commission, the California Independent System Operator (CAISO), and the California Air Resources Board. DRA also provides consumer representation in other forums related to the CPUC's proceedings such as meetings to review utility procurement decisions, the Low-Income Oversight Board (LIOB), telecommunication public policy committees, industry committees of the National Association of State Utility Consumer Advocates (NASUCA), and the Pacific Forest and Watershed Stewardship Council.

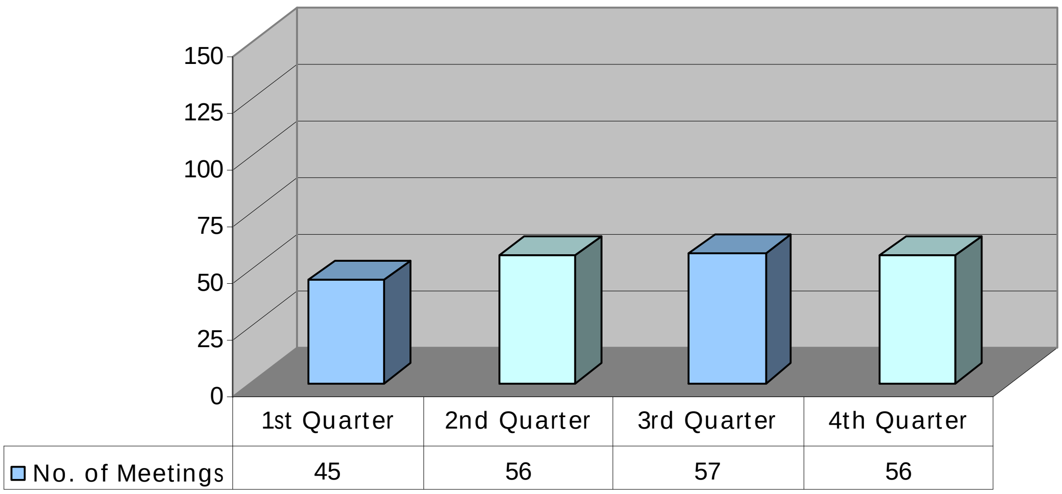
[8] An Advice Letter is a filing by a utility seeking authority to spend ratepayer money or set/change policies which may have a significant impact on ratepayers. Utility requests via advice letters are typically authorized by a CPUC decision adopted in a formal proceeding, which sets certain parameters for determining whether the advice letter request is valid and should be granted.

DRA Outreach and Education:

DRA has also developed measures to improve the quality of its work product and increase the effectiveness of its advocacy efforts. In this regard, DRA also measures its CPUC lobbying efforts by tracking the number of contacts it has with commissioners and their advisors in connection with CPUC proceedings.

DRA met with Commissioners and/or their Advisors over 200 times.

Number of DRA Lobbying Visits to Commissioner Offices in 2011[9]



DRA reached the public through the media approximately 120 times.

In its effort to create greater transparency of the CPUC decision-making process and its outcomes that affect the daily lives of Californians, DRA's media outreach efforts resulted in approximately 120 press mentions in large and small California media outlets across the state. Additionally, DRA aided in providing the ratepayer perspective in numerous other news stories.

DRA works with a wide variety of stakeholders including small business organizations, community and environmental groups, and other consumer oriented organizations to augment the voice of customers.

[9] This figure reflects the number of meetings between DRA representatives and CPUC Commissioners or their Advisors.

Lobbying in Sacramento

DRA actively participates in the Legislative and Budget processes in Sacramento by working directly with the Governor's office, Legislature, Department of Finance, Legislative Analyst's Office, and other related entities. DRA achieves its statutory mission to represent and protect energy, gas, water and communications investor-owned utility customers in Sacramento by:

- Taking positions on bills.
- Testifying in informational and bill hearings.
- Providing technical legislative and constituent assistance.
- Participating in working groups.
- Providing updates on CPUC and DRA actions.

DRA does this by maintaining a full-time presence in Sacramento. DRA worked directly with Member offices and testified on many consumer protection bills in 2011:

Energy

- **AB 37 (Huffman)** -- Would require the CPUC to identify alternative options for investor-owned utility customers that decline the installation of wireless advanced metering infrastructure devices (smart meters).

- **AB 904 (Skinner)** -- Would require the CPUC to ensure energy efficiency programs result in real reductions in energy consumption.

- **AB 1124 (Skinner)** -- Would deliver increased energy efficiency savings and associated health and welfare benefits to low-income renters living in multi-family buildings.

- **AB 1214 (Skinner)** -- Would require the CPUC to find as "necessary for the present or future public convenience and necessity" any electrical grid construction or upgrades that have already been approved by the CAISO and FERC.

- **SB X1 2 (Simitian)** -- Accelerated California's Renewable Portfolio Standard to 33% by December 31, 2020.

- **SB 142 (Rubio)** -- Would eliminate rate protections for usage up to 130% of baseline for all ratepayers including CARE and non-CARE customers and direct the CPUC to adjust the rates currently charged to customers for electricity usage in order to eliminate, by no later than January 1, 2015, the current tiered residential electricity rates.

- **SB 674 (Padilla)** -- Protects the personal information of electric and gas consumers that use advanced metering infrastructure (smart meters).

- **SB 790 (Leno)** -- Helps communities that want to manage their own electricity procurement and generation needs by removing unnecessary burdens and undue constraints in the existing Community Choice Aggregation process.

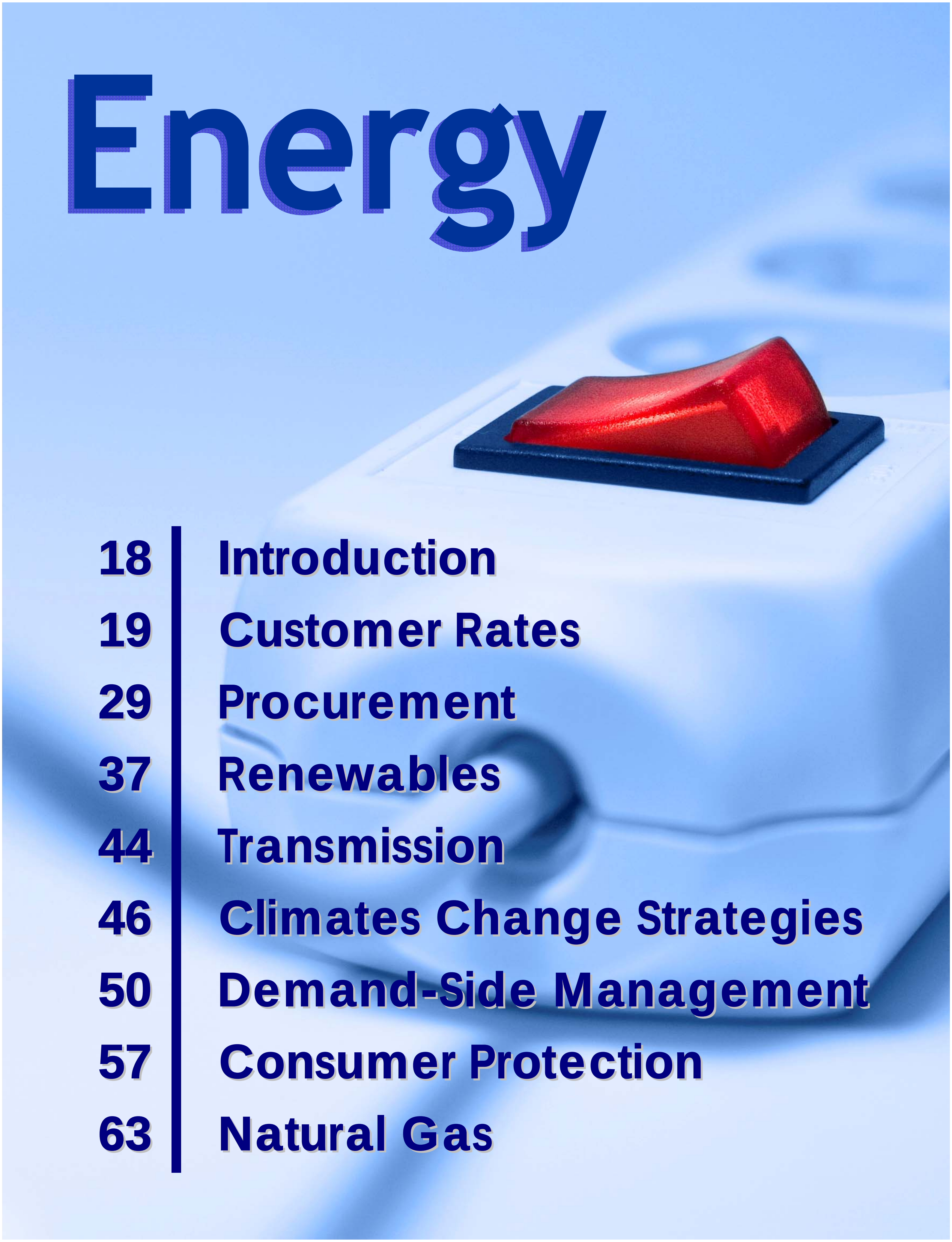
- **SB 836 (Padilla)** -- Requires the CPUC to release to the Legislature as specified, the costs of all electricity procurement contracts for eligible renewable energy resources and all costs for utility-owned generation.

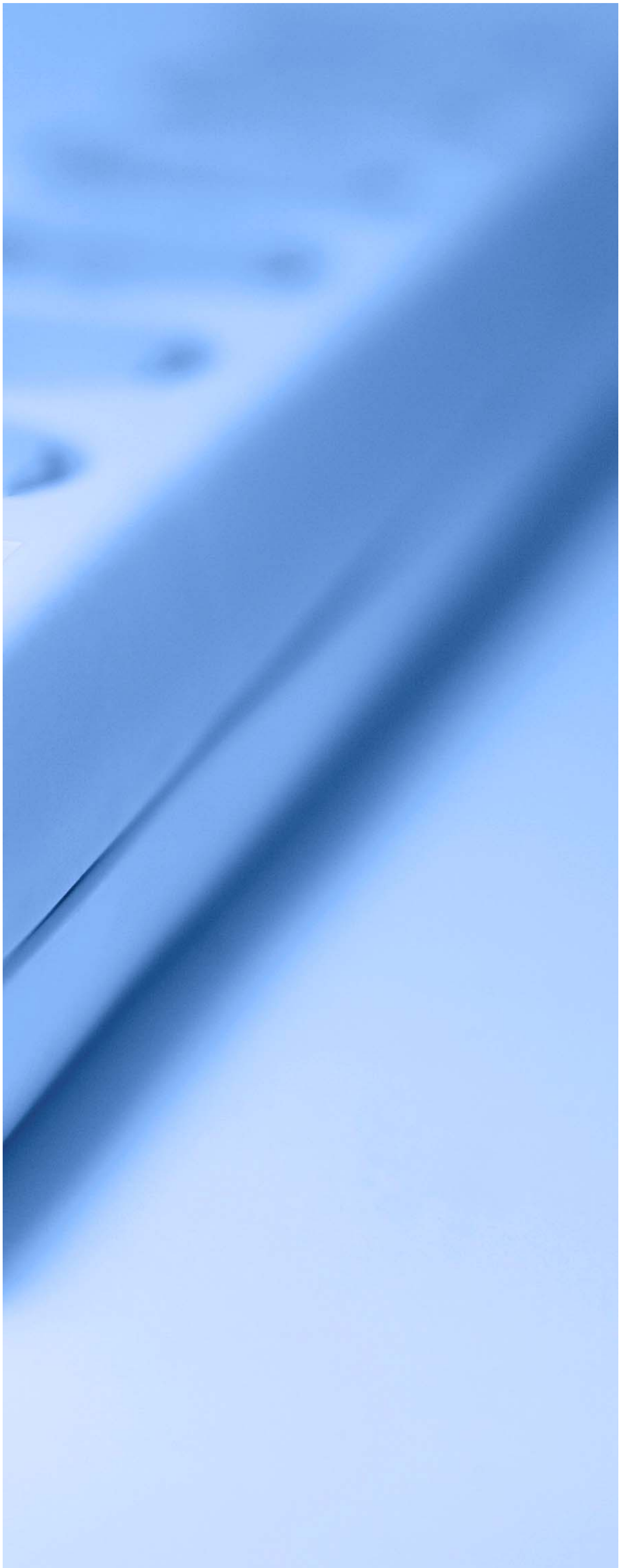
Communications

- **SB 379 (Fuller)** -- Would expand access to advanced telecommunications and information services to specified institutions, community-based organizations, and governmental entities in recognition of their economic and societal impacts.

- **SB 905 (Wolk)** -- Would better protect consumers from unauthorized charges being placed on their home telephone and wireless bills.

Energy





At a time when California's energy policies are significantly evolving, DRA's mission remains unchanged, which is to ensure that energy customers receive safe and reliable service at reasonable prices.

Energy customers are the most important stakeholders when it comes to setting and carrying out the state's energy policy goals. With this in mind, DRA will continue to advocate that all energy services and programs should deliver expected benefits and are provided at the lowest cost possible.

Recent natural gas explosions that tragically resulted in loss of life and property, have resulted in DRA expanding its focus on the energy utilities' safety-related programs. In 2012, DRA will strive to ensure that the costs the utilities claim are necessary to implement safety programs are justified and reasonable.

DRA supports the state's goal to significantly reduce greenhouse gas emissions. Numerous customer-funded programs aimed at increasing procurement of electricity generated from renewable resources are underway. DRA will continue to evaluate whether these programs are meeting the state's energy policy goals and are being implemented in the most cost-effective manner possible while not compromising the intended purpose of the programs.

DRA will remain focused on advocating for the state's most vulnerable energy customers – low income, seniors, and the disabled – to ensure that they receive affordable energy service. DRA will propose improvements to the utilities' low income and other assistance programs to close the Affordability Gap. DRA will also continue to argue for improved customer outreach and billing practices that prevent customers' energy service from being disconnected for non-payment, as well as for disconnection policies that are safe, fair, and reasonable.

INTRODUCTION

During 2011, DRA's energy advocacy efforts focused on seeking to meet California's progressive energy goals in the most affordable manner for residential and small business customers. Additionally, DRA sought to ensure that the utilities' procurement activities reflected California's loading order, but did not exceed need, which would cause customers to double-pay for unneeded energy at a time when investor owned utilities' reserve margins are upwards of 40% above need. The magnitude of customer funds requested in 2011 across General Rate Cases, Fossil Fuel and Renewable generation procurement, and Demand-side management activities was more than $20 billion. DRA's advocacy activities saved customers approximately $4.1 billion.

DRA worked on rate case issues for California's four largest investor owned utilities, which had requested to increase their revenues by nearly $10 billion. Meanwhile, Smart Grid deployment, which will likely have a significant impact on future customer utility bills, commenced with the submission of utility plans for CPUC approval, but without the inclusion of any budget projections. DRA also proposed an alternative plan to the CPUC's Critical Peak Pricing scheme for California's small business customers.

DRA supports California's climate change goals and the role of renewables to aid in meeting those goals. Yet 2011 resulted in approval of some of the most overpriced renewables contracts, despite the utilities being on-track to meet their Renewable Portfolio Standard (RPS) goals. A competitive market in renewable resources should result in better prices for customers.

On the customer protection side, DRA was successful in achieving generally strong Smart Grid privacy rules to protect customers' energy usage data and limit access to personally identifiable information. Additionally, DRA was effective in achieving additional time for stakeholders to make recommendations to improve low-income assistance programs in order to shape programs that will have a larger impact on the affordability gap that exists for the most at-risk customers. In the wake of the San Bruno natural gas pipeline explosion, in 2011 DRA augmented its natural gas staff in order to provide increased scrutiny of utility requests and expenditures to ensure that ratepayers receive the lowest possible rates for the safest service.

In this chapter, DRA summarizes its 2011 analytical and advocacy activities outlining achievements on behalf of ratepayers as well as policies and significant costs that will impact ratepayers in the future.

CUSTOMER RATES

Pacific Gas & Electric

2011 General Rate Case

In May 2011, the CPUC issued a decision which adopted the settlement agreement of seventeen parties, including DRA. The agreement allows PG&E to receive a cumulative base revenue increase of $1.7 billion for the 3-year period covering 2011, 2012, and 2013.

In 2009, PG&E had originally requested a 3-year, cumulative revenue increase of nearly $4.2 billion for its electric distribution, gas distribution, and electric generation operations. After a detailed analysis of PG&E's request, in 2010 DRA released its reports which found that only a $1.0 billion cumulative increase in revenues was reasonable for 2011-2013.

DRA's analysis and negotiation aided in saving PG&E customers $2.47 billion for 2011 through 2013.

$2.47 billion

Cumulative savings for 3 year GRC time frame of 2011 – 2013

Final PG&E 2011 GRC Revenue Requirement
(in Millions of Dollars)

Year	Present Revenues	Settlement Outcome for PG&E's 2011-2013 Revenue Requirement		
		Increase	Yearly Total	Percent Increase
2011	$5,587	$395	$5,977	7.1%
2012		$180	$6,157	3.0%
2013		$185	$6,342	3.0%

Rate Design: Customer Charge

In March 2010, as part of its Rate Design proceeding, PG&E requested the CPUC allow it to introduce a fixed charge of $3 per month for **Non-CARE** residential customers and a fixed charge of $2.40 per month for **CARE** (low-income) customers.

DRA opposed PG&E's request and argued that this proposal violated the rate protections from ***SB 695 (Kehoe, 2009)***, Public Utilities Code Section 739,that limited rate increases for usage up to 130% of the baseline level. The imposition of a residential customer charge would essentially be an effective rate increase for tier 1 usage greater than the 3% allowed by PU Code 739.9(a). The imposition of a CARE customer charge was not justified because there was no increase in the ***CalWORK escalator***.

What is it?

SB 695 (Kehoe, 2009): Resulted in P.U. Code Sections 739.9(a) and 739.1(b)(2), which set allowable rate increases for non-CARE and CARE customers for usage up to 130% of baseline usage.

- **Non-CARE Rates:** Usage up to 130% of the baseline level are allowed to increase from 3% to 5% per year following a formula related to the consumer price index.
- **CARE Rates:** Usage up to 130% of the baseline level are allowed to increase up to 3% per year based on percentage increases in benefits under the CalWORKs program authorized by the Legislature.

On January 1, 2011, PG&E increased Non-CARE residential tier 1 and tier 2 rates by the allowable 3% and made no change to CARE rates because there was no increase to benefits to the CalWORKs program, which provides temporary financial and employment assistance to eligible families.

CalwWORKS Escalator: The benefit amounts provided under the CalWORKs program are subject to an annual cost of living adjustment, effective July 1st of each year, as provided under Section 11453(a) of the Welfare and Institutions (W&I) Code.

In May 2011, the Commission unanimously adopted DRA's position and rejected PG&E's request for the customer charge. In July, PG&E, Edison, and the Kern County Taxpayers Association filed a joint application for rehearing to overturn the CPUC's decision. DRA and other parties opposed the rehearing. The application for rehearing is pending. In 2012, DRA expects that SDG&E will also ask for a customer charge in its General Rate Case.

Customer Energy Statement

As part of its 2011 General Rate Case, PG&E submitted a revised proposal in April 2011 seeking $34.7 million to redesign its customer utility bill format to be implemented in 2013. DRA recommended a much lower funding level of $16.3 million given that more targeted expenditures on specific areas would better effectuate consumer impact and still meet need of:

- Revisions required by legislation and regulatory orders.
- Clarity and ease for customers to understand their bills and make informed energy usage decisions.
- Reasonable funding to implement a bill redesign project that meets customer and regulatory needs.

$15.7 million
Savings for PG&E
Customer Bill Redesign

DRA negotiated a more than 40% cost reduction from the bill redesign proposal as well as a process for obtaining greater consumer stakeholder involvement in developing a new bill format that can provide information to customers for effective energy consumption decisions. DRA, PG&E, and other parties reached an all-party settlement in November 2011. The main features of the settlement are:

- PG&E may recover up to $19 million in implementation costs.
- PG&E will engage in both qualitative and quantitative customer research to achieve a bill design that makes the customer energy statement clear and understandable, while assisting customers to make informed energy usage choices.
- In addition to English, the new bill format will be made available in Spanish and Chinese, as well as a format that will be friendly to customers with disabilities.

A proposed decision on the settlement is expected in early 2012.

Peak Time Rebates

As part of its 2010 Rate Design efforts, PG&E submitted a proposal to the CPUC in compliance with 2009 CPUC direction to design a two-part peak-time rebate program. PG&E requested to implement residential ***Peak Time Rebate (PTR)*** for eligible customers. Customers could earn a PTR rebate for up to 15 "event days" per year. PG&E sought approval to recover $32.7 million in incremental costs that are incurred to implement PTR in 2010 through 2013. This proceeding was suspended by the CPUC in October 2010 and recommenced in August 2011 with a goal of a May 1, 2013 partial implementation. However, PG&E now proposes that PTR be consolidated with its ***Default Residential Rates*** proceeding. This may result in an indefinite suspension of work on PTR pending an overall CPUC review of residential time-variant rates. In response to PG&E's proposed consolidation, DRA proposed to consolidate PTR with PG&E's 2012 Rate Design proceeding. This would likely delay PTR implementation until the summer of 2014.

DRA supports residential PTR at levels that are consistent with the economic benefits of peak demand reduction because it provides a low-risk incentive for customers to reduce their electricity usage. PTR is a customer-friendly solution that should take priority over other PG&E dynamic rate programs (e.g., ***SmartRate*** and residential ***Peak Day Pricing***). DRA's key issues are to ensure that:

- The size of the rebates are appropriate (in cents per kWh).
- PG&E's funding request is reasonable.
- There is coordination with PG&E's present and planned residential dynamic rate programs.

DRA expects to submit its testimony to the CPUC in January 2012 with hearings expected in February and a final decision expected in July 2012. PG&E estimates that this schedule will allow PTR to be implemented in two phases beginning in the spring of 2013. However if, the CPUC grants PG&E's motion for consolidation, the schedule to implement PTR will be suspended pending CPUC action on the consolidated proceeding. If the CPUC grants DRA's consolidation proposal, it is likely that the current PTR schedule would be delayed approximately six months, with a final decision expected in January 2013 and full PTR implementation in May 2014.

WHAT IS IT?

Peak Time Rebate: A utility bill rebate is determined by comparing a customer's kWh usage during a peak event with a customer's actual usage during a specific period of time prior to the peak event period. If the customer's usage during the peak-event period is less than the customer reference level, the customer qualifies for a rebate.

Peak Day Pricing (PDP): A combination of ***CPP*** with a mild ***TOU*** rate design.

Critical Peak Pricing (CPP): This is a dynamic rate that allows a predetermined short-term price increase to reflect system conditions expected on the following day.

Time-of-Use (TOU): A rate in which the price of electricity varies by preset usage periods (e.g., by time of day, day of the week, and season).

Default Residential Rates: A residential rate schedule which would automatically apply to an eligible residential customer, unless the customer actively indicates a different choice, by "opting out."

SmartRate: PG&E's voluntary residential CPP rate, which superimposes CPP rates on a tiered rate design.

Energy Resources Recovery Account

In February 2011, PG&E filed its 2010 ***Energy Resources Recovery Account (ERRA)*** compliance requesting the CPUC approve its 2010 procurement costs. DRA's analysis showed that PG&E did not dispatch its energy resources in the least-cost manner. DRA recommended a disallowance of $37.5 million based on DRA's findings that PG&E did not operate its owned generation consistent with CPUC requirements. CPUC hearings are expected on this issue in 2012.

WHAT IS IT?

Energy Resources Recovery Account (ERRA): The ERRA is an account set up to track the costs the utility incurs and the revenues it receives to cover the cost of generating electricity and purchasing electricity from generators. The ERRA process is where the account is reconciled so that rates are adjusted to equal actual costs of procurement by comparing the utilities' actual expenses with forecasted expenses for a given year to ensure prudent fiscal management of energy procurement expenses. These costs include fuel costs for operating gas-powered generators, payments to other generators for renewable and conventional power, and hedging costs. The CPUC requires the utilities to prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner, consistent with the utilities' approved procurement plan. DRA is often the only party representing ratepayers to ensure that revenue over-collection is refunded to customers via reduced rates.

Silicon Valley Technology Center Solar

In July 2011, PG&E requested a $17.8 million increase in electric rates and charges to fund a one phase silicon photovoltaic (PV) manufacturing facility. PG&E requested ratepayer funds to match a Department of Energy grant of $30 million. DRA led a coordinated protest with other concerned parties to dismiss the $17.8 million request because PG&E failed to provide a valid reason why its ratepayers should subsidize, through electricity rates and charges, the Silicon Valley Technology Center (SVTC) Solar project without any demonstrated ratepayer benefit. At a meeting held by the CPUC in September 2011, an Administrative Law Judge echoed DRA's concerns that PG&E had failed to provide any compelling reasons to support the use of ratepayer funds for this project. The CPUC should not set a precedent to invest ratepayer dollars in private for-profit ventures where even banks and venture capitalists have declined to take on the risk. PG&E's request is pending before the CPUC.

Southern California Edison

2012 General Rate Case

In November 2010, Southern California Edison (Edison) submitted a request to the CPUC for a 3-year, cumulative General Rate Case (GRC) revenue increase of nearly $4.6 billion for 2012 through 2014. The request covered Edison's electric operations, including generation, transmission, and distribution. In May 2011, DRA submitted its reports to the CPUC which supported only an $830 million cumulative increase for the three year period.

Evidentiary hearings were held during July and August of 2011. The outcome of this proceeding is still pending before the CPUC. A CPUC proposed decision is expected to be issued in early 2012.

Edison's 2012-2014 GRC
(in Millions of Dollars)

Year	Present Revenues	Edison's Proposals for 2012-2014 Revenue Requirement			DRA's Recommendations for 2012-2014 Revenue Requirement		
		Increase	Yearly Total	Percent Increase	Increase	Yearly Total	Percent Increase
2012	$5,348	$938	$6,285	17.5%	$92	$5,439	1.7%
2013		$598	$6,884	9.5%	$219	$5,658	4.0%
2014		$612	$7,496	8.9%	$119	$5,777	2.1%

2012-2014 Rate Design

In June of 2011, Edison proposed updates to its customer rate design for 2012-2014, requesting to:

- Reduce the ***baseline allowance***.
- Establish separate baseline allowances for single-family and multi-family dwellings.
- Increase the residential customer charge from 0.88 $/month to $6.00 for single-family dwellings and $4.68 for multi-family dwellings.

These proposals are designed to reduce rates in the higher ***tiers***, which absent the changes would increase from 29.9 to 35.8 cents/kWh if Edison's revenue requirement increases were adopted. DRA opposed Edison's proposal to increase the residential customer charge, and Edison subsequently withdrew this recommendation. Edison also proposed to default small businesses to Time-of-Use rates by 2012, which are rates that vary generally by season and time of day.

DRA submitted its report in December 2011 recommending that various changes to Edison's estimates of marginal costs that would result in a 0.9% decrease in residential average rates and an 11.8% decrease in small business average rates. DRA also recommended to:

- Reject Edison's proposal for separate residential baseline allowances for single-family and multi-family dwellings.
- Reject Edison's recommendation to reduce the baseline allowances to 50% of average customer electricity usage.
- Phase-in Time-of-Use (TOU) rates at a slower rate.
- Not default customers to TOU rates until 2014.

Hearings are expected to be held in May 2012. The CPUC is expected to issue a decision by November 2012.

WHAT IS IT?

Baseline Allowance: Baseline allowance provides residential electric and natural gas customers with an energy allowance for basic energy needs at a tier one rate. It is dependent on the season and the territory in which the customer lives. For example in the summer season, it varies between 9.1 kWh per day for coastal customers in the Santa Barbara region to 43.9 kWh per day for inland customers in Palm Springs.

Rate Tiers: Most California residential electricity rates have four rate levels, or four tiers. Tier 1 is the lowest rate to make it affordable for basic energy needs.

Catastrophic Events Memorandum Account (CEMA)

In June 2010, Edison filed an amended application seeking CPUC authorization to include in rates the costs associated with 2007 wind and firestorms recorded in its ***Catastrophic Events Memorandum Account (CEMA)***. Edison ultimately sought approval for $6.84 million in increased operation and maintenance (O&M) expenses and $9.49 million in increased capital expenditures for a total annual revenue requirement request of $10.39 million. DRA protested the request in order to conduct an audit and recommended that costs associated with Edison facilities having a role in the fires should not be recoverable.

WHAT IS IT?

Catastrophic Events Memorandum Account (CEMA): A rate adjustment mechanism intended to allow California utilities to recover through rates their reasonable costs incurred for restoring service and repairing or replacing facilities following a catastrophic event. The event must be declared a disaster by the appropriate federal or state authorities.

In March 2011, Edison and DRA filed a settlement agreement which reduced Edison's total annual revenue requirement request by $2.32 million and reflected adjustments for removal of:

- $1.1 million in incremental O&M expenses reflecting the removal of the entire $0.68 million in incremental O&M expenses related to the Canyon / Malibu fire and the entire $0.42 million in incremental O&M expenses related to the Grass Valley fire.
- $0.87 million in capital-related revenue requirement associated with $1.9 million in capital expenditures.
- $0.35 million in interest expense.

Edison would recover $8.1 million or 78% of its requested revenue requirement of $10.4 million.

In July 2011, the Commission adopted the settlement agreement.

Energy Resources Recovery Account

In 2011, DRA litigated Edison's 2009 power plant outages as part of its annual ***Energy Resources Recovery Account (ERRA)*** [see p. 21] review. DRA recommended a disallowance of $2.4 million based on a finding that two power plant outages were not reasonable due to Edison's mismanagement:

- **SONGS Unit 2:** DRA used facts contained in Edison's Root Cause Evaluation (RCE) report and testimony to support the unreasonableness of a 48-hour outage at the SONGS Unit 2 power plant given that Edison admitted the outage was due to the improper reassembly of a vent valve. DRA recommended a disallowance of $1,442,200.

- **Mammoth Pool Unit 2:** DRA's analysis found that Edison:
  - Ran the generator at high temperatures for short-term energy gain despite Edison admitting that running the generator at high temperatures reduces its life.
  - Did not perform a cost-benefit analysis to evaluate running the generator at excessive temperatures.
  - Did not employ the *"reasonable manager"* standard in operating the plant at higher than recommended temperatures for several years, causing the generator to prematurely fail.
  - Ran the generator at excessive temperatures resulted in a Mammoth Pool plant life that was 40% shorter than typical.

DRA recommended a disallowance of $979,350.

In October 2011, the Commission adopted DRA's recommendation to disallow Edison's request for $2.4 million, agreeing that the plant outages were unreasonable.

Additionally, in 2011, DRA reviewed Edison's 2010 ERRA compliance filing that requested the CPUC approve its 2010 fuel procurement costs. DRA's analysis showed that PG&E did not dispatch its energy resources in a least-cost manner. DRA recommended a disallowance of $12.2 million based on its findings that Edison did not operate its owned generation consistent with CPUC requirements. CPUC hearings are expected on this issue in 2012.

$2.4 million
Savings for Edison Customers due to Power Plant Outages

San Diego Gas & Electric

2012 General Rate Case

San Diego Gas & Electric Company filed its General Rate Case (GRC) in December 2010, requesting to increase customer rates by $277 million plus $52 million in smart meter related revenues for a total requested increase of $329 million.

DRA issued its reports in September 2011 recommending that customer rates should be decreased by $45.6 million due to lower estimates for operation and maintenance expense, depreciation expense, income tax expense, and a lower estimate of rate base which results in a lower return on rate base.

Comparison of SDG&E Requested Increase to DRA Recommended Decrease

Year	SDG&E Increase (millions)	DRA Increase (Decrease) (millions)
2012	$329*	$(45.6)
2013	49.0	29.0
2014	64.0	31.0
2015	81.0	31.0

*Includes $52 million in smart meter-related revenue

CPUC hearings were held in November and December of 2011. A CPUC decision is expected in 2012.

2012-2014 Rate Design

In October of 2011, SDG&E proposed updates to its customer rate design for 2012-2014, requesting to establish:

- A network usage charge that would increase costs to ***Net Energy Metering*** (NEM) customers, but leave costs the same for most non-NEM customers. The network usage charge would require customers to pay for the use of the distribution system when those exports are made.
- A residential customer charge of $3 per month to recover costs associated with serving customers including meter costs, billing, and customer services.
- A program where customers could pre-pay for electricity rather than paying a deposit to establish service or certain fees to re-establish service after a disconnection.
- A proposed Tariff Rule 20D to facilitate undergrounding distribution system infrastructure in rural areas to promote fire safety.

WHAT IS IT?

Net Energy Metering: An approach to meter reading specifically designed for customers who have solar panels and other forms of self-generation. It nets the electricity that is exported from the customer's site to the utility distribution grid at times when the self-generation exceeds the customer's on-site usage.

Subsequently, DRA supported the Utility Consumers Action Network's (UCAN) motion for a CPUC preliminary ruling finding that various aspects of SDG&E's rate design proposals violate the PU Code. The motion has not been acted upon by the CPUC.

DRA is in the process of reviewing SDG&E's rate design application and will be developing its position for submission to the CPUC in 2012. DRA likely will oppose SDG&E's institution of a $3 per month customer charge and its use of a different method for calculating the underlying marginal customer costs than what the CPUC has previously adopted. The CPUC is expected to establish the proceeding schedule in early 2012.

Energy Resources Recovery Account

During 2011, DRA litigated SDG&E's 2009 ***Energy Resource Recovery Account (ERRA)*** [see p. 21] in hearings at the CPUC. In October, 2011, the CPUC ruled that two of Edison's SONGS power plant outages were unreasonable. Because SDG&E has a 20% ownership in SONGS, DRA therefore recommended imposing disallowances for SDG&E as well.

In December 2011, DRA issued its findings on SDG&E's 2010 ERRA compliance, recommending a $7.2 million disallowance for SDG&E's management of its owned generation resources. DRA expects to participate in hearings on this issue in 2012.

Southern California Gas

2012 General Rate Case

Southern California Gas Company (SoCalGas) filed its General Rate Case (GRC) application in December 2010, requesting to increase customer rates. DRA issued its report in September 2011 recommending that customer rates should decrease because customer growth has flattened and DRA is skeptical of SoCalGas' forecast of capital expenditures, operating costs, and post-2012 costs.

SoCalGas requested a $306 million increase for 2012 (or 7.4%) while DRA recommended a decrease of $62.8 million (or 3.7%).

Hearings were held in November and December of 2011. A CPUC decision is expected in 2012.

SoCalGas 2012 General Rate Case
($ millions)

	2012	2103	2014	2015
SoCalGas Request	$ 306	$ 55	$ 62	$ 51
DRA Recommendation	(62.8)	32	34	34

Bear Valley

Catastrophic Events Memorandum Account (CEMA)

WHAT IS IT?

Catastrophic Events Memorandum Account (CEMA): A rate adjustment mechanism intended to allow California utilities to recover through rates their reasonable costs incurred for restoring service and repairing or replacing facilities following a catastrophic event. The event must be declared a disaster by the appropriate federal or state authorities.

In June 2011, Bear Valley requested CPUC authorization to increase rates by 2.1 % to recover $858,658 in costs in its ***Catastrophic Events Memorandum Account (CEMA)*** associated with the state's requirement to address Bark Beetle infestation mitigation and the 2010 winter storms. The costs associated with:

- Bark Beetle mitigation are $550,890.
- 2010 winter storms are $307,768.

DRA protested the request in order to audit the costs and determine their reasonableness.

In October 2011, DRA and Bear Valley reached a settlement in principle. The settlement is expected to be submitted to the CPUC for approval in January 2012. A final Commission decision is expected later in 2012.

Market Redesign and Technology Upgrade (MRTU)

Market Redesign and Technology Upgrade (MRTU)

In 2011, DRA filed a motion with the CPUC to bifurcate and consolidate the ***Market Redesign and Technology Upgrade (MRTU)*** issue from the individual utility ***Energy Resource Recovery Account (ERRA)*** [see p. 21] compliance process.

DRA asserted that the MRTU cost analysis will be more comprehensive if all three investor owned electric utilities are reviewed together given that MRTU costs are driven by common CAISO directives of tariff, structure, timeline, and technical requirements. In addition, a consolidated proceeding will provide CPUC efficiency of resources and centralize expertise in this complex subject matter.

In August 2011, the Commission approved DRA's motion to bifurcate MRTU from ERRA and to consolidate it into its own proceeding for Edison, PG&E, and SDG&E. In April 2012, the utilities will jointly organize and host a workshop to present their report and respond to questions from parties and CPUC staff.

What is it?

Market Redesign and Technology Upgrade (MRTU): The California Independent System Operator's (CAISO) initiative to upgrade the efficiency of energy dispatch and improve the current wholesale electricity market system through new market features and advanced computer software technology. The CAISO, charged with managing California's electricity grid and regulated by the FERC, implemented MRTU in 2009. MRTU is intended to:

- Enhance wholesale market efficiencies through use of a more accurate grid model.
- Provide more transparent prices for generation and delivery of energy.
- Enhance electric reliability by coordinating with the CPUC's Resource Adequacy program.
- Prevent market manipulation by market participants.

Smart Grid

Deployment Plans

In 2010, the CPUC adopted requirements for ***Smart Grid*** Deployment Plans and required the utilities to submit proposals containing their Deployment Plans by July 1, 2011, pursuant to ***SB 17 (Padilla, 2009)***. The decision also called for developing final metrics for measuring progress of Smart Grid implementation.

Edison, PG&E, and SDG&E submitted their deployment plans in July 2011. DRA is currently reviewing the utilities' plans and intends to promote strategies to efficiently and cost-effectively implement Smart Grid deployment in a manner that builds on infrastructure and programs already in place. DRA is developing a proposal for how the CPUC should utilize the Deployment Plans as well as how to evaluate Smart Grid funding requests to ensure ratepayer benefit. In January 2012, the CPUC will commence workshops. A final CPUC decision must be adopted by July 1, 2012.

What is it?

Smart Grid: According to the Federal Smart Grid Task Force, "A Smart Grid is an automated, widely distributed energy delivery network that is characterized by a two-way flow of electricity and information, as well as enhanced monitoring. A Smart Grid incorporates the benefits of advanced communications and information technologies to deliver real-time information and enable the near-instantaneous balance of supply and demand on the electrical grid."

Senate Bill (SB) 17 (Padilla, 2009): Requires "the state to modernize the state's electrical transmission and distribution system to maintain safe, reliable, efficient, and sure electrical service, with infrastructure that can meet future growth in demand." The CPUC, in consultation with the Energy Commission, CAISO, and other key stakeholders, were required to determine the criteria for a Smart Grid Deployment Plan consistent with policies set forth in the bill, and federal law, by July 1, 2010. Additionally, the investor owned utilities were required to submit Deployment Plans for CPUC consideration by July 1, 2011. The CPUC must approve Deployment Plans by July 1, 2012.

Direct Access

In 2011, the CPUC sought to update and reform the ratesetting methodologies and rules applicable to ***Direct Access (DA)*** service in recognition of regulatory and industry changes that had occurred since 2006, in order to ensure cost responsibility is appropriately assigned.

Specifically, the CPUC sought to:

- Revise the methodology for the ***Market Price Benchmark (MPB)*** used to calculate DA customers' cost responsibility necessary to maintain bundled customer indifference.
- Review the rules governing the rights and obligations for switching between bundled and DA services.
- Define the applicable Energy Service Provider (ESP) financial security requirements required by Public Utilities Code Section 394.25(e).

What is it?

Direct Access (DA): A retail service option allowing eligible customers to purchase electricity directly from an independent electric service provider (ESP) rather than from an investor owned utility. In 2001, Assembly Bill 1X required the CPUC to suspend Direct Access service as of September 20, 2001 for customers not already on Direct Access. In 2009, Senate Bill 695 (Kehoe) permitted a limited return to Direct Access service subject to an increased maximum kilowatt-hour limitation on DA transactions. Except for this increase, the previously enacted suspension of DA transactions remains in effect.

Any modification to the methodologies and rules applicable to DA service must be consistent with the CPUC's intent to prevent cost-shifting and to ensure that bundled customers remain indifferent, i.e., no better off or worse off, when other customers depart utility bundled service and elect DA service. In 2006, the CPUC last adopted major changes in methodologies to determine surcharges on DA and departing load customers to ensure that cost responsibility continues to be accurately assigned and consistent with the principles of bundled ratepayer indifference.

Market Price Benchmark (MPB): Proxy price used to estimate the market value of resources in the utility resource portfolio for purpose of determining departing customers' cost responsibility. The per-unit cost of the total portfolio is compared against the market price benchmark to determine the uneconomic costs.

DRA supported the CPUC's efforts to update Direct Access rules due to market and regulatory changes in California since the suspension of Direct Access was enacted in 2001. DRA made a variety of policy recommendations to help prevent cost-shifting to the remaining bundled customers when customers switch between utility bundled service and Direct Access service:

- Revise the MPB methodology to recognize renewable resource attributes, but attributes should be correctly valued using publicly available, transparent data.
- Remove load-related California Independent System Operator (CAISO) costs from the total portfolio calculation and conforming changes in the MPB calculation with changes to the Transitional Bundled Service (TBS) rate, which is based on the market rate for electricity.
- Retain the existing six-month advance notice requirement for switching between bundled and DA services.
- Define the re-entry fees to include both the administrative and procurement costs to hold ESPs responsible for risks relating to an involuntary return.

In December 2011, the CPUC issued a decision which incorporated many of DRA's recommendations to aid in preventing cost-shifting to bundled customers when other customers depart service from the utility. The decision also:

- Revised the **Market Price Benchmark (MPB)** methodology to recognize renewable resource attributes.
- Removed the load-related CAISO costs from the total portfolio.
- Reflected the profile of the supply portfolio.
- Reflected the market price for resource adequacy (RA) capacity.

DRA was instrumental in ensuring that the cost of all renewable resources a utility uses to serve customers during the year are used to determine the value of renewable resource attributes. This ensures that departing customers' cost responsibility is correctly calculated in order to prevent cost shifting to other bundled customers.

The decision also retained the existing six-month advance notice requirement for switching, but reduced the minimum stay requirement to eighteen months. DRA advocated vigorously to preserve the six-month advance notice requirement, so that utilities have adequate time to adjust their portfolios in order to prevent cost shifting. The decision found that residential and small commercial Direct Access customers may not possess the same degree of business sophistication in terms of protecting themselves in the event of a breach by their ESP. Therefore, the decision defined re-entry fees to include both the administrative and procurement costs for residential and small commercial Direct Access customers, but only the administrative costs for medium and large Direct Access customers. The decision permits involuntarily returned residential and small commercial Direct Access customers to return to bundled portfolio service (BPS) immediately, but requires involuntarily returned medium and large Direct Access customers to be placed on TBS for six months prior to returning to bundled service. DRA prefers to hold ESPs responsible for all risks related to an involuntary return. Yet the CPUC's decision appears sufficient to guard against cost-shifting to bundled customers from involuntary returns.

In 2012, DRA will work with the CPUC to determine the appropriate methodology for calculating the applicable ESP bond provision to cover the risk of incremental procurement costs for residential and small commercial Direct Access customers involuntarily returned to bundled service.

Wildfire Expense Balancing Accounts

In August 2009, the four major investor owned utilities in California filed applications requesting CPUC authorization to establish wildfire expense balancing accounts (WEBA) in order to record all wildfire related costs for future cost recovery. In August 2010, the utilities submitted a joint amended application asserting that the proposed WEBA is intended to reduce financial uncertainty associated with damaging and costly wildfires that cause personal and property damages in excess of utility insurance coverage.

In September 2011, DRA submitted its report recommending that the proposed WEBA be rejected because there is no benefit to ratepayers or the regulatory process by adopting it. A special application is an option for a utility facing an extraordinary burden due to extraordinary wildfire costs. The CPUC should address such unusual incidents on a "case-by-case" basis.

In November 2011, Edison and PG&E filed a motion to withdraw as applicants to the WEBA proceeding.

Procurement

Long-Term Procurement Planning (LTPP)

In 2010, the CPUC established a broader three-track proceeding for the ***Long-Term Procurement Plan (LTPP)*** covering planning years 2010 – 2020. Each track addresses separate policy issues:

- **Track One:** The long-term ***system*** (i.e., state-wide California Independent System Operator [CAISO] system) need and local resource adequacy planning.
- **Track Two:** Investor owned utilities' ***bundled*** customer need (individual plans for Edison, PG&E, and SDG&E).
- **Track Three:** Rules and policy issues related to procurement (i.e., Convergence Bidding, GHG compliance, Once-Through Cooling, and Utility-Owned Generation).

Track Two was addressed first with Tracks One and Three being addressed together.

What is it?

Long-Term Procurement Planning (LTPP): The LTPP proceeding is the umbrella proceeding for all procurement-related activity at the CPUC, including Renewable and Fossil Fuel procurement, Resource Adequacy (RA), Energy Efficiency (EE), and Demand Response (DR). Every two-years the CPUC reviews and refines procurement policies, practices, and procedures in the investor owned utilities' (IOUs) long-term procurement plans, establishing an "up-front standard" of reasonableness for utility procurement activities and cost recovery. The role of the LTPP is to facilitate cost-effective investment in new fossil fuel generation consistent with the state's investments in renewable energy per 1) the Renewables Portfolio Standard (RPS) program; and 2) other preferred resources as outlined in the state's Energy Action Plan (EAP) Loading Order. It does this by assessing both the utilities' **bundled need** (that is, resources required to meet the need of customers in their respective service territories) and the overall **system need** (resources required to meet the state's demand for energy including municipal utilities). The LTPP does not replace the policy-making function of other energy proceedings, but rather complements those proceedings through a comprehensive compliance showing and an integrated analysis of current policy.

LTPP Track Two

In March 2011, the utilities submitted their individual Track Two bundled procurement plans for resource needs forecasted for their respective service territories. DRA performed extensive analysis and discovery and submitted testimony in May 2011. DRA found that in the time since the 2006 LTPP decision, the utilities had made no significant progress or changes to their overall and day-to-day procurement activities that brought them closer to complying with the state's Loading Order or Greenhouse Gas (GHG) reduction goals. DRA recommended a need for greater oversight by the CPUC in order to ensure utility compliance with California's energy policy goals.

In November 2011, the CPUC issued a Track Two proposed decision which largely adopted DRA's key recommendations on **Hedging** (see page 30)

and other issues, acknowledging that the utilities should adhere to the Loading Order even when procuring to meet their day-to-day needs. The Commission is expected to vote on the proposed decision in early 2012.

LTPP Tracks One and Three

In August 2011, the utilities submitted testimony on Tracks One and Three, identifying any system need and other procurement related issues. The CAISO also submitted the results of its renewable integration modeling exercise. SDG&E was the only utility to request 450 megawatts of new generation to make up for plant retirements in its current fleet. DRA reviewed each of the utilities' system plans as well as the results of the CAISO renewable integration modeling exercise and found:

- No additional need for any of the utilities - including SDG&E - due to high planning reserve margins.
- The results of the CAISO modeling exercise exaggerated the need for new resources without taking into account the flexibility of the existing fleet.

DRA participated in a Track One settlement agreement and confirmed its position that no additional procurement is needed in this LTPP cycle due to surpluses in the utilities' service areas. In August 2011, DRA participated in CPUC hearings and challenged SDG&E's need assumption. DRA argued that SDG&E had not given adequate credit to Energy Efficiency and Demand Response programs (which would reduce the need to procure more energy) and that the higher load growth forecasted for their service area was unsupported. DRA asserted that SDG&E's request would cause ratepayers to pay for unneeded energy.

A proposed decision on Tracks One and Three is expected in early 2012. Once a final decision on the 2010-2020 LTPP proceeding has been issued, a new LTPP proceeding is scheduled to begin which will examine the need for the next ten-year cycle of 2012 – 2022.

Procurement Review Groups

DRA actively participated in the Procurement Review Groups (PRGs) for three of the largest investor owned electric utilities throughout 2011. These groups are organized by the hosting utility for each service area. They are comprised of a range of stakeholders including DRA, TURN, CPUC's Energy Division, Department of Water and Power, and the Union of Concerned Scientists. DRA provided input into the power procurement activities of Edison, PG&E, and SDG&E on the following topics with the goal to ensure that electricity procurement is cost-effective for ratepayers:

- Contracting and Requests for Proposals for various short- and mid-term energy power products.
- Estimates of energy net-short and net-long positions.
- Risk management strategies for procurement of energy.
- Contracts for Renewable projects.
- Compliance with the greenhouse gas cap and trade regulation.
- Other procurement activities.

DRA's informal review and input ensures that utilities' procurement activities are consistent with their long-term procurement plans, thereby improving regulatory certainty. Through the PRGs, DRA closely monitors the utilities' competitive energy solicitations to ensure that the design, implementation, and results of these solicitations meet ratepayer needs for cost-effective electricity procurement.

Hedging

Utility financial ***Hedging*** plans were submitted as part of the utilities' 2010-2020 Long-term Procurement Planning (LTPP) process. Decisions from the LTPP proceeding will authorize energy hedging activities intended to stabilize rates and to refine hedging policies at the CPUC.

What is it?

Energy Hedging: Functions as a form of insurance designed to protect ratepayers against large cost increases from volatility in energy prices. PU Code 454.5 requires that electric corporation procurement plans assess the risk of potential price increases in their portfolios. The risk assessment is an analysis of utility portfolio volatility and the probability of price increases (known as the **TEVaR)**. Specific measures to moderate price risk are mandated by PU Code 454.5 and authority to hedge with financial and other electricity-related product contracts is granted.

What is it?

In 2002, CPUC decision D.02-08-071 created policies to regulate hedging using two benchmarks for hedging limits:

The Expiration Value at Risk (TEVaR): An estimate, at a given confidence level, of the amount of electric price increase that could occur due to changes in market conditions. The current 95% TEVaR measures 1 in 20 worst case scenarios.

Consumer Risk Tolerance (CRT): The price that an average consumer would be willing to pay to reduce the risk of higher prices in the future. It is currently set at 1 cent per kilowatt hour.

Hedging policies and authorizations became part of Long-term Procurement Planning (LTPP) in 2006. Risk and Hedging measurements are reported to the CPUC on a monthly, quarterly, and yearly basis. The Procurement Review Groups (PRG), in which DRA is an active participant, regularly reviews utility hedging reports.

The Hedging plans submitted by the utilities included descriptions of portfolio risk assessment, ***TEVaR*** methodology, ***CRT*** thresholds, credit and collateral requirements, procurement products, hedging strategies, and other issues - both public and confidential. The utilities' plans did not support increases in the *CRT* or greater oversight of Hedging regulations, as endorsed by DRA.

DRA's analysis showed that the cost impact of financial Hedging reported in the utilities' CPUC annual filings demonstrate the aggregated costs of electric portfolio financial Hedging was 1.7 billion dollars. DRA questioned the high cost of financial Hedging relative to its value to ratepayers, who pay for the Hedging costs. While DRA supports Hedging as a strategy to protect customers from price spikes in the energy market, it is only one of many forms of Hedging the IOUs participate in. Most of the utility energy transactions hedge financial risk and include multi-year contracts, energy auctions, planning reserve margins, and a variety of programs instituted by the CPUC to address price volatility. All Hedging costs and methods should be efficient and cost-effective.

DRA recommended measures that would maintain adequate consumer protections while assuring that costs are minimal:

- **Index and adjust the Consumer Risk Tolerance (CRT):** Will keep Hedging from increasing disproportionately and adjusting the CRT upward will reduce Hedging costs.
- **Implement an independent review of utility Hedging:** Examination of the interaction of various programs to ensure that ratepayers are not paying excessively for rate stability.
- **Establish best practices measures:** Ten years of experience post-energy crisis, it is time for the CPUC to thoroughly review Hedging activities and consider policy refinements.

In response to DRA's concerns to control excessive Hedging costs, in 2011 the utilities revised their Hedging proposals, which are forecasted to significantly reduce Hedging costs while maintaining stable energy rates. DRA proposed changes to the CPUC's Hedging framework related to the CRT which are predicted to significantly reduce Hedging, potentially saving hundreds of millions of dollars annually for ratepayers.

In December 2011, the CPUC issued a proposed decision for the 2010-2020 Long-Term Procurement Plan Track Two [see p. 29], adopting DRA's proposals to increase and index the CRT. These changes will lead to greatly reduced Hedging costs for ratepayers.

In 2012, DRA will closely monitor Hedging changes approved by the CPUC in the LTPP proceeding. The Hedging planning process is expected to be completed in early 2013.

Resource Adequacy

DRA participated in the CPUC's annual process to refine the ***Resource Adequacy*** needs for California's investor owned utilities. Each year the CPUC develops a variety of new issues to assure the Resource Adequacy program meets its goals in a rapidly evolving energy environment. DRA

What is it?

Resource Adequacy (RA): Created in response to the California energy crisis of 2000-2001 this program requires load serving entities (such as the investor owned utilities, energy service providers, and community choice aggregators) to guarantee reliable delivery of electricity by entering into procurement contracts one year in advance. Resource Adequacy ensures that the California Independent System Operator (CAISO) has sufficient resources when and where needed. Public Utilities (PU) Code 380 required the CPUC to provide a RA regulatory framework. The CPUC instituted annual reviews to continually refine RA programs for reliability of system resources and local area reliability.

helped to shape the scope of the proceeding for such issues developing new requirements for programs to assess penalties for utilities that fail to adhere to Resource Adequacy regulations, Demand Response, accounting for power plant outages, and diesel back-up units.

DRA supports a Resource Adequacy program which provides reliable energy to ratepayers at the lowest possible rate. In the current Resource Adequacy proceeding, DRA advocated for:

- No drastic reductions in penalties for utilities that violate RA guidelines because compliance with CPUC regulations requires appropriate enforcement.
- Changes in new Demand Response program rules to prevent the reduction of RA credits for these important programs.

Additionally, DRA was active in the development of the 2011 California Independent System Operator (CAISO) local area capacity technical study that sets annual requirements for local Resource Adequacy areas. This CAISO report is used by the CPUC to aid in determining the amount of Resource Adequacy needed to be purchased by the utilities to ensure reliability of delivering electricity to customers. DRA advocated for a new seasonal analysis by the CAISO which was adopted by the CPUC. This analysis is predicted to lead to reductions in procurement and savings for ratepayers. DRA was successful in encouraging some major policy proposals, such as Demand Response accounting procedures, to be considered in a subsequent proceeding.

The Resource Adequacy proceedings in 2012 will consider numerous issues that impact ratepayers, such as the integration of renewable resources and distributed generation, as these resources expand under legislative direction.

Convergence Bidding

In 2010 the CPUC issued a final decision granting the utilities interim authority to participate in **Convergence Bidding** in the CAISO markets, adopting DRA's recommendation to grant each utility only *interim authority* to participate in convergence bidding.

In February 2011, Convergence Bidding commenced in California. The utilities were subsequently authorized by the CPUC to participate in the convergence bidding market in California. Through August 2011, the CAISO's Department of Market Monitoring (DMM) assessed that the Convergence Bidding program has had little, or no, benefit in improving price convergence or the efficiency of Day-Ahead unit commitment decisions. Additionally, the CAISO assessed that virtual bidding strategies being employed by market participants to profit from price divergence in the Day-Ahead market and Hour-Ahead scheduling process at **interties** have led to an estimated $44 million in charges that are allocated to all ratepayers in the CAISO's system. As a result, in November 2011 the Federal Energy Regulatory Commission (FERC) issued a response confirming the CAISO's request to remove Convergence Bidding at intertie scheduling points.

What is it?

Convergence Bidding: Also known as "virtual bidding," a financial instrument, which is not backed by any physical generation or load, designed to allow market participants to take **arbitrage** opportunities in expected price differences between Day-Ahead and Real-Time markets. In February 2010, the Federal Energy Regulatory Commission (FERC) ordered CAISO to open its energy market to convergence bidding by February 2011 asserting that convergence bidding should cause the Day-Ahead and Real-Time prices to "converge," and thus improve price stability and market efficiency. In response, the CPUC addressed Convergence Bidding within the Long-Term Procurement Planning proceeding (R.10-05-006) with the primary goal of managing price risk, promoting rate stability, and protecting ratepayers against excessive costs.

Arbitrage: The purchase of securities on one market for immediate resale on another market in order to profit from a price discrepancy.

CAISO Intertie: An energy scheduling point at a location where the CAISO Balancing Authority Area and another Balancing Authority Area are interconnected.

Based on the CASIO's assessment, DRA maintained its position that it is too early to lessen regulatory oversight and control over the utilities' Convergence Bidding activities. DRA recommended that the CPUC review the utilities' Convergence Bidding activities in 2012, after one full year of Convergence Bidding, in order to evaluate the effects of Convergence Bidding. This will allow the CPUC and stakeholders to measure the relative success and failures of utility bidding strategies, as well as to assess whether the benefits outweigh the costs to customers. The

CPUC's review should result in whether or not to extend or modify the upfront standards initially authorized for Convergence Bidding. In response to an Edison request to broaden its Convergence Bidding authority, the CPUC LTPP Track II proposed decision supports DRA's position that it is too soon to change the Convergence Bidding rules for the investor owned utilities. A final decision is expected in early 2012.

Procurement Contracts

SDG&E Power Purchase Tolling Agreement

In May 2011, SDG&E requested CPUC approval for three long-term ***Power Purchase Tolling Agreements (PPTAs)*** based on the CPUC's approved 2006 Long-Term Procurement Plan (LTPP). The PPTAs would add approximately 450 MW of capacity to SDG&E's local service area by June 1, 2014, the last online date of the three PPTAs.

What is it?

Power Purchase Tolling Agreements (PPTAs): PPTAs are contracts to purchase power wherein the utility pays the seller a periodic payment for capacity for the length of the contract. The utility is responsible for the procurement and delivery of the fuel (e.g., natural gas) to the seller's power plant generating units, and the scheduling of the generating units under contract. Hence, utility customers take all the upside and downside risks of fuel price volatility.

In September 2011, DRA disputed SDG&E's claim that the utility still has the authority to contract for the 450 MW of capacity because SDG&E's need for electricity has changed as reflected in the more recent 2010-2020 Long-term Procurement Proceeding (LTPP). DRA recommended that SDG&E's application be denied without prejudice until the CPUC has finalized the 2010-2020 LTPP proceeding. DRA asserted that SDG&E should amend its request to conform to the approved 2010-2020 long-term procurement plan for Local Capacity Requirements (LCR) as determined through 2020. Otherwise, SDG&E customers would pay for unneeded power upwards of $1.9 billion over 25 years.

Combined Heat and Power Feed-in Tariff

To comply with AB 1613, in December 2010 the CPUC ordered the investor-owned utilities to file revised contracts for **Combined Heat and Power** (CHP) facilities that were under 20 MW, under 5 MW, and under 500 kW. Prior to this decision, the program had been challenging to implement because the CPUC and utilities could not agree on an avoided cost or whether the CPUC was preempting the Federal Regulatory Commission (FERC) by setting wholesale energy prices. In January 2011, the utilities submitted proposed contracts to the CPUC for less than 20 MW and under 5 MW facilities. In September 2011, the CPUC issued a draft resolution approving, with modifications, the utilities' proposed contracts.

What is it?

The California Legislature passed AB 1613 (Blakeslee, 2007) in order to implement a ***Combined Heat and Power (CHP) Feed-in-Tariff (FiT)*** for new, small and efficient CHP plants. The purpose of this bill was to encourage the construction of small CHP. Increased use of energy from CHP is part of the California Air Resource Board's plan to reduce greenhouse gases.

Combined Heat and Power (CHP): System that produces, from a single fuel input, both electricity and thermal energy (such as heat or steam). The fuel types may be natural gas, coal, oil, renewable. These systems are used for industrial, commercial, heating, or cooling purposes. Use of these systems typically results in reducing demand for electricity from grid. Examples of CHP facilities are hospitals, universities, and ice rinks.

Feed-in-Tariff (FiT): An economic policy created to promote active investment in and production of specific energy sources. Feed-in-Tariffs typically make use of long-term agreements and pricing tied to costs of production for renewable energy producers.

Resource Adequacy Capacity: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. IOUs are required to procure a certain amount of resource adequacy to help ensure reliability of electricity to customers.

DRA opposed the CPUC's finding, advocating that the utilities would not be able to count the Resource Adequacy capacity from the CHP facilities, and in effect, ratepayers would have to double-procure Resource Adequacy capacity to compensate. In response to DRA's' concerns, the CPUC made substantive changes and issued a revised draft resolution, which required:

- Larger CHP units to participate in a deliverability study to properly assess the capacity a generator is able to provide to a utility to meet its Resource Adequacy obligations.
- Utilities will not be required to pay the high price for the larger CHP units until those units can be counted for RA purposes.
- An interim solution for smaller CHP units to reduce the Resource Adequacy obligation of the service area by the total generation capacity of the smaller CHP units.
- **Resource Adequacy capacity** for the smaller CHP units will be determined in either the Distributed Generation or the new Resource Adequacy proceeding, going forward.

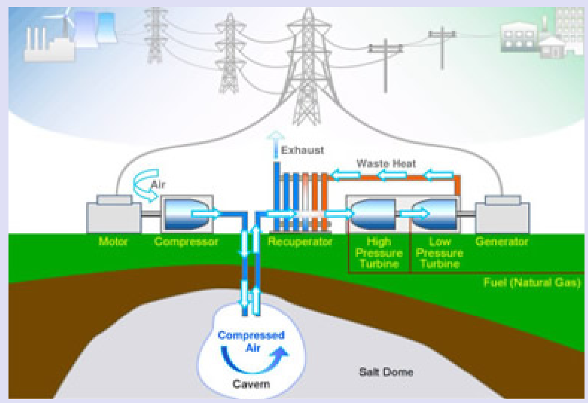
The Commission approved the final resolution in December 2011, which provides increased protection for ratepayers.

Energy Storage

In December 2010, the CPUC opened a proceeding to develop ***Energy Storage*** procurement targets pursuant to AB 2514 (Skinner, 2010). DRA supports procurement of cost-effective energy storage; however, the quantity of storage needed should be based on each Load Serving Entity's (LSE) specific procurement needs. Accordingly, DRA asserted that the CPUC should not adopt specific target levels for Energy Storage, since there are many different types of storage applications, with varying requirements. Therefore, adopting a pre-determined quantity of storage levels will result in a sub-optimal solution that would likely result in unnecessary costs to the ratepayers. DRA also recommended that existing barriers to Energy Storage be removed and Energy Storage should be allowed to compete with all other resources on a level playing field by modifying CAISO rules and tariffs, as well as utility tariffs.

WHAT IS IT?

Energy Storage: Used mainly, among other things, as a means of storing energy during off-peak periods when electricity is cheaper and using the stored energy during on-peak periods when energy is at its highest price. There are many forms of energy storage, such as battery, fly wheel, pumped storage, and compressed air. These technologies help avoid building expensive new capacity to meet the peak and may provide an effective means for addressing the challenges of relying upon intermittent and off-peak renewable generation. Assembly Bill 2514 (Skinner, 2010), directed the CPUC to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for each Load-Serving Entity (LSE) to procure viable and cost-effective energy storage systems. By October 1, 2013, the CPUC is required to adopt energy storage system procurement targets, which should be achieved by each LSE by December 31, 2015 – a second target is to be achieved by December 31, 2020.



Compressed Air Energy Storage Process

PG&E Pumped Storage

In 2010, PG&E filed an application seeking CPUC approval to recover $31.9 million for hydroelectric ***Pumped Storage*** located in Amador County that it projected could provide up to 1,200 megawatts of energy storage capability by 2020. DRA protested the non-cost-effective project based on lack of need given PG&E's excess generation planning reserve margin of nearly 40 percent. DRA also asserted that the request was duplicative and premature since Assembly Bill 2514

WHAT IS IT?

Pumped Storage Hydroelectricity: A type of hydroelectric power generation used to serve load during periods of high demand. The method stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. At times of low electrical demand, excess generation capacity is used to pump water in the higher reservoir. When there is higher demand, water is released back into the lower reservoir through a turbine, generating electricity.

(Skinner, 2010) requires the CPUC first to establish utility procurement targets for viable and cost-effective Energy Storage systems. The CPUC, in December 2010, subsequently opened a rulemaking to develop energy storage targets, if appropriate.

In the spring of 2011, as part of the CPUC's Long-Term Procurement Planning proceeding, the CPUC requested the California Independent System Operator (CAISO) run four electrical grid simulation scenarios to determine if any energy storage capability was needed through the year 2020. On May 2011, the CAISO issued a report to the CPUC with the results of those studies, which showed that no energy storage capability was needed through the year 2020.

In May and June 2011, DRA reviewed the CAISO's study and concurred with CAISO's conclusion that there is no need for PG&E's pumped storage facility to accomplish the state's 33% renewables goal. DRA recommended that the CPUC dismiss the application without prejudice. In September 2011, the Commission adopted DRA's recommendations in its final decision and dismissed PG&E's application without prejudice.

A CPUC proposed decision identifying Energy Storage targets for utilities is expected in the first quarter of 2012.

RENEWABLES

Renewable Portfolio Standard (RPS)

In 2011, the CPUC established two tracks in the ***Renewable Portfolio Standard (RPS)*** proceeding to comply with SB 2(1x) (Simitian, 2011):

Track 1: The purpose was to define Renewables portfolio content categories of in-state, ***firmed-and-shaped***, and ***unbundled.***

DRA supported the need to define the three product categories for a timely implementation of SB 2(1x) in order to achieve California's expanded renewables goals. DRA advocated for:

- The restriction of **Category 1** projects to only bundled products.
- An interpretation of **Category 2** eligible projects as those that would permit utilities to purchase ***Unbundled Renewable Energy Credits (RECs)*** along with a conventional power contract, as long as both were submitted to the CPUC at the same time.

In December 2011 the Commission issued a final decision that adopted DRA's recommendations.

Track 2: The purpose was to develop intermediate milestone goals that the utilities should achieve to reach their 33% renewables goal by 2020. DRA advocated for the CPUC to prioritize the implementation of a cost containment mechanism, as envisioned by SB2(1x). The CPUC intends to address this issue in early 2012.

In December 2011, the Commission issued a decision which determined goals for each year between 2011 and 2020. The RPS legislation determined that the utilities should achieve milestone goals for retail sales from renewables:

- 20% between 2011 to 2013.
- 25% by 2016.
- 33% by 2020.

The CPUC was tasked with determining goals for the intervening years and approved the following:

- 21.7% of retail sales for 2014.
- 23.3% of retail sales for 2015.
- 27% of retail sales for 2017.
- 29% of retail sales for 2018.
- 31% of retail sales for 2019.

DRA supports the 33% renewable goal and plans to actively participate in the RPS proceeding in 2012 when the CPUC expects to address cost containment and other outstanding issues for implementing SB 2(1x).

Renewable Power Purchase Agreements (PPAs)

In 2011, California's investor owned utilities signed many contracts for the 2011-2013 period with the objective of reaching their mandatory goal of 20% Renewables Portfolio Standard (RPS). The contracts will begin to operate in future years in order to meet the state's 33% RPS goals by 2020. Renewable Power Purchase Agreements (PPAs) are one of the utilities' major sources for meeting California's RPS goals.

DRA supports PPAs as a way of meeting the RPS goals but is concerned that the abundance of overpriced contracts approved by the CPUC in 2011 will have adverse effects on the renewable market and will unnecessarily result in higher utility bills for customers. Sending higher price signals to the market may result in future PPAs that are higher-priced than they would be otherwise. Many of the Renewable projects that were proposed or approved in 2011 were often substantially above the ***Market Price Referent (MPR)***. Contract prices are confidential until 3 years after a project comes online.

Notable examples of overpriced PPAs in 2011 include:

- **CSolar South:** SDG&E contract for a 97-130 MW solar facility. DRA protested the project because it included a utility buy-out option where SDG&E could become the owner of the facility, which would be an unnecessary burden on ratepayers. The price exceeded the 2009 MPR, yet the Commission approved the contract without modifications.
- **Arlington Wind:** PG&E contract for a 103 MW wind facility. DRA protested the project

What is it?

Market Price Referent (MPR): Established in Public Utilities Code § 399.15(c), the MPR represents the market price of electricity. It requires the CPUC to establish the MPR through a methodology that considers: long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities; the value of different products, including baseload, peaking; and as-available generation, as well as an adder for GHG reduction benefits. It is used as a benchmark to assess the above-market costs of Renewable Portfolio Standard (RPS) contracts and can serve to contain the total cost of the RPS program.

What is it?

The California Renewable Portfolio Standard (RPS): The program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002) and codified in California Public Utilities Code § 399.11, et seq. The statute requires that each investor owned utility increase its total procurement of eligible renewable energy by at least one percent of annual retail sales per year, so that 20% of its retail sales are supplied by eligible renewable energy resources by 2017. In 2006, SB 107 (Simitian, 2006) officially accelerated the state's RPS target to 20% by the end of 2010. SBX1 2 (Simitian, 2011) increased the target to 33% by the end of 2020 requiring retail sales to average 20% renewable generation from 2011 to 2013 and established an interim target of 25% renewable generation by the end of 2016.

SB 2(1x) limits the amount of renewables that utilities can procure out-of-state by creating three categories of RPS projects: in-state, ***firmed-and-shaped*** out-of-state, and unbundled out-of-state. Those categories are limited as follows:

Category 1: Projects interconnected to a California ***balancing authority*** *OR* ***dynamically transferred*** into a California balancing authority *OR* projects which can be scheduled into a California balancing authority without substituting electricity.
Category 2: Projects **firmed-and-shaped** which are interconnected outside of a California balancing authority but have associated energy imports into California and also provide Renewable Energy Credits (RECs).
Category 3: Projects which provide only RECs.

SB2(1x) Restrictions on Meeting RPS Obligations

Compliance Period	In-state	Out of State	
		Unbundled RECs	Firmed and Shaped
2011-2013	at least 50%	up to 25%	the remainder
2014-2016	at least 65%	up to 15%	the remainder
2017-2020	at least 75%	up to 10%	the remainder

Balancing Authority: The entity responsible for integrating resource plans in advance maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Dynamically Transferred: A method by which load or generation is moved, on a real-time basis, from the Control Area where they physically reside to a second Control Area where they do not physically reside.

Firmed-and-Shaped: **Firming** refers to the process by which a backup resource is used to supplement the output of an intermittent renewable resource to ensure that the total energy provided is sufficient to meet customer load. **Shaping** is the capability of the supplementary resource to fluctuate in concert with the intermittent renewable resource such that the sum of the two equals the total load at any given point in time. Firming-and-Shaping is a solution for a load serving entity to invest in renewable energy options which may be intermittent and still meet the energy needs of its customers.

Unbundled Renewable Energy Credit (REC): Represents the environmental attribute of a renewable energy resource, separate from its associated energy.

because of a proposed price increase. This project is still awaiting resolution.

- **Energía Sierra Juárez:** SDG&E contract for a 100-156 MW wind facility. DRA's analysis indicated potentially high transmission network upgrade costs. The Commission has not yet voted on this project.
- **DG Fairhaven:** PG&E contract for a 16 MW biomass facility. DRA protested this project due to the high price and length of the contract, specifically due to the options to extend beyond the initial 3-year term of the contract because PG&E does not need the contract to fulfill its RPS requirements past 2014. The Commission approved this PPA.
- **Soitec:** SDG&E contract for five concentrated solar PV contracts with SDG&E for 160 MW. DRA protested this project on the basis of it being high priced. The Commission approved the PPAs along with a new option to expand the project to an additional 300 MW.
- **Abengoa Solar Thermal Facility:** PG&E contract for a 250 MW thermal facility significantly above market price. PG&E could have purchased twice the power for the money it will spend on this contract. DRA's analysis showed that PG&E already demonstrated sufficient portfolio diversity with a number of other solar thermal facilities. The Commission approved the project in November 2011.
- **North Star Solar:** PG&E contract for a 60 MW Solar PV facility which DRA protested as one more overpriced renewables contracts in 2011. The Commission approved the project in October 2011.

DRA's analysis compared the price of a renewable proposal to the market price benchmark, the Market Price Referent (MPR), as well as comparable offers. The proposals which were not competitive, DRA protested on the basis of price.

As DRA found in its November 2010 report, ***Green Rush,*** there is no need for the CPUC to approve all contracts that appear before it because the utilities are well on their way to meeting their 33% RPS goals and can afford to take more time to consider cost and bringing down the cost of renewables within the industry, as well as for customers. Collectively, the large IOUs reported in their August 2011 RPS compliance filings that they served 17.0% of their electricity with RPS-eligible generation in 2010. The utilities have each served their 2010 load with RPS-eligible renewable energy:

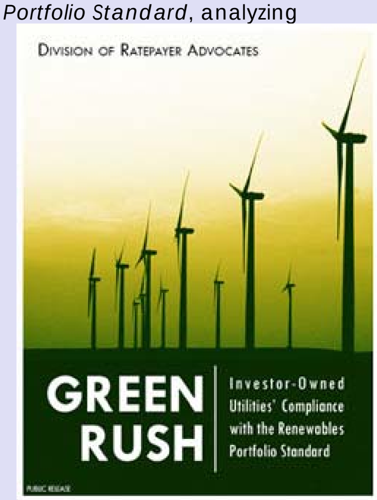
- PG&E served 15.9%.
- Edison with 19.3%.
- SDG&E with 11.9%.

By the end of 2011, 2,541 MW of new renewable capacity has achieved commercial operation under the RPS program, collectively for all the utilities. More than 830 MW of new renewable capacity came online by the 4th quarter of 2011, with an additional 166 MW forecasted to have come online by the end of 2011.

In 2011, the utilities submitted 49 contracts to the CPUC for approval, representing 3,133 MW of renewable generation. The Commission approved approximately a dozen renewable PPAs in 2011. The CPUC did not reject any renewable PPAs in 2011 that it had the opportunity to vote on. In 2012, DRA will continue to scrutinize RPS contracts to ensure they are cost competitive.

What is it?

Green Rush Report: In December 2010, DRA released its report, *Green Rush: Investor-Owned Utilities' Compliance with the Renewables Portfolio Standard*, analyzing California investor-owned utilities' progress in renewable procurement and outlining ratepayer concerns with their renewable strategies. DRA's report finds that utilities are well on their way to meeting the 20 percent goal as well as a 33 percent renewable level. However, DRA's analysis finds that the CPUC has continued to approve renewable contracts more expensive than outlined standards, and that utilities have exceeded the Legislature's above-market fund cost cap by more than $5 billion. The report encourages the CPUC to be more discriminating in its approval of utility contracts for renewable procurement. *Green Rush* outlines specific measures that could help the CPUC bring ratepayer costs down while maintaining flexibility to help California get more of its power from sustainable, clean, renewable technologies. The *Green Rush* report can be found at: http://www.dra.ca.gov/DRA/energy/Renewables/greenrush.htm



PG&E Manzana Wind Project

In March 2011, the Commission rejected PG&E's 2009 request to recover $911 million from its customers to purchase a 246 MW wind farm in Kern County. DRA had reviewed PG&E's project proposal and strongly advocated against the project because it presented numerous risks to ratepayers. DRA asserted that:

- PG&E did not have need for the project.
- Risks to project viability were not sufficiently considered including:
  - Under-performance
  - Violations of endangered species laws
  - Costly delays
- The project was not cost competitive.

$911 million

Savings for PG&E Customers

The CPUC's final March decision agreed with DRA's analyses and provided guidance on how to evaluate similar proposals in the future.

Renewable Contracts

Rim Rock Wind Power Facility

In July 2010, SDG&E requested CPUC approval to purchase ***Renewable Energy Credits (RECs)*** associated with the Rim Rock wind power project located in Montana through a first-of-its-kind proposed ***tax equity*** investment, of up to $600 million. SDG&E had already signed an agreement with the wind facility that would provide a large portion of its Renewable Portfolio Standard (RPS) compliance. SDG&E asserted that given the challenges of finding traditional financing, a creative financing strategy was needed in order to fund the project at reasonable rates.

What is it?

Renewable Energy Credits (RECs): A method by which compliance with RPS is demonstrated. One REC is equivalent to one RPS-eligible megawatt-hour that a utility purchases. A renewable generator produces two outputs simultaneously: electricity and an environmental attribute. RECs are certificates that represent the environmental attributes of renewable production. For every megawatt-hour of electricity produced by a renewable generator, a corresponding REC is also produced. In order to be eligible for RPS compliance, credits must be fully accounted for by the Western Renewable Energy Generation Information System (WREGIS).

Tax Equity: Tax Equity financing has been a reliable source of funding renewable energy projects for the past decade. Tax Equity financing is a renewable energy financing structure that permits investors to efficiently and economically utilize federal tax benefits generated by the investment available in renewable energy projects.

DRA articulated concerns that the project could be too risky for ratepayers:

- Transmission line required for the project was not yet built.
- Delays and other project uncertainties could play a role in Rim Rock's ability to come online.
- Ratepayers would bear too much financial risk from the size of the investment.
- Inexperience with this type of capacity could result in project under-performance.
- SDG&E shareholders would not bear any of the risk.

DRA litigated these issues, which resulted in an all-party settlement that succeeded in reducing the size of the tax equity investment by more than half and the size of the power purchase agreement by more than a third. DRA also received concessions of substantial ratepayer protections, including:

- A 10% shareholder investment in the project – the first of its kind.
- Shareholders would be repaid for their investment *after* ratepayers.
- A role for ratepayer advocates in the oversight of the transaction.

The Commission approved the settlement in July 2011. The facility is scheduled to begin construction in 2012.

Renewable Auction Mechanism

In December 2010, the CPUC approved the ***Renewable Auction Mechanism (RAM)*** decision, identifying it as the preferred procurement mechanism for renewable energy projects under 20 MWs. The decision requires the utilities to hold two auctions per calendar year over a two-year period. The first RAM auction closed on November 15, 2011 and a shortlist of selected bids from the auction will be finalized by early 2012.

> **WHAT IS IT?**
>
> **Renewable Auction Mechanism (RAM):** A market-based procurement mechanism for renewable energy projects up to 20 MWs that is used to select projects from a competitive auction based on least cost.

Due to the anticipation surrounding the RAM program and the success of similar utility programs marketed at smaller renewable energy projects, DRA anticipates the participation in the auctions to be substantial and robust. As recommended by DRA, the CPUC required an independent evaluator to review and report on the utilities' Renewable Portfolio Standard (RPS) solicitation, bid evaluation, and selection process.

DRA supports the RAM program as it should spur the development of smaller-scale, cost-effective renewable energy projects in the near-term and at the local distribution level. In particular, DRA envisions that the RAM will encourage distribution level renewable projects that reduce the need for more costly transmission projects. Potential ratepayer savings could be attributed to costs avoided by utilizing existing transmission and distribution lines.

In 2012, DRA will monitor the RAM shortlist selection process by participating in the investor owned utilities' Procurement Review Group process and reviewing utility advice letters seeking approval of the finalized shortlist of bids which will be submitted in early 2012. The next auction is required to take place no later than March 31, 2012.

Mountainview Renewable Energy Credit Transaction

In January 2011, the CPUC issued a decision allowing all utilities to use Renewable Energy Credits (RECs) to meet their RPS obligations. The Mountainview Purchase Power (MVPP) was the first request to the CPUC for the novation of a DWR contract in the aftermath of the 2001 energy crisis, and therefore it required the CPUC to carefully assess its policy on novated contracts.

> **WHAT IS IT?**
>
> **Contract Novation:** To terminate or cancel the terms of an existing contract and substitute them with another.

DRA submitted a joint settlement agreement with Edison in May 2011 recommending:

- DWR contract should be ***novated***.
- MVPP transactions should be deemed an eligible renewable energy resource.
- Edison should receive the RECs associated with this contract which should count towards the utility's renewables goal.

DRA supports the use of RECs for Renewable Portfolio Standard (RPS) compliance from eligible renewable resource and recommended that the CPUC address the following issues:

- RECs associated with MVPP transactions should be properly tracked and retired in the Western Region Energy Generation Information System (WREGIS) tracking system, in order to count towards RPS compliance.
- The California Energy Commission should ensure that energy from the MVPP transactions are delivered from an RPS eligible resource.
- The CPUC should review and verify that the renewable energy from the MVPP transactions count towards Edison's RPS compliance.

DRA expects the CPUC to address the settlement agreement in 2012.

California Solar Initiative (CSI)

In 2011, SB 585 (Kehoe) augmented the $2 billion ***California Solar Initiative (CSI)*** program, administered by the CPUC, by an additional $200 million to ensure adequate funds are available to pay customers incentives. In June 2011, the CPUC expanded ***Virtual Net Metering*** to all multi-tenant properties beyond affordable housing properties. It also expanded the definition of property as contiguous parcels under common ownership and made changes to the incentive structure for Multifamily Solar Housing (MASH).

What is it?

California Solar Initiative (CSI): The CPUC established the CSI program in 2006 with the goal of realizing a 10-year market transformation program that would result in declining monetary incentives through 2016 and drive down solar technology prices. The CPUC established a CSI goal to install 1,940 megawatts (MW) of solar energy systems by 2017. The CPUC addressed low-income solar programs in two significant decisions: the Single Family Affordable Solar Housing (SASH) program was established in 2007; the Multifamily Affordable Solar Housing (MASH) program and Virtual Net Metering (VNM) in 2008.

Virtual Net Metering (VNM): VNM allows electricity generated from a single solar energy system on a multi-tenant or multi-meter property to be allocated as kilowatt-hour (kWh) credits to either common areas of the property or to individually metered tenant accounts. It does not require the system to be physically interconnected to each tenant's meter.

These changes were consistent with DRA's position because they would result in more megawatts of solar per ratepayer dollar invested. DRA generally supports the CSI program, which has stimulated demand for rooftop solar photovoltaic installations and appears to have helped drive down prices.

The CPUC adopted a decision in December 2011 that increased the CSI budget by $200 million, as authorized by SB 585. The increase in CSI funds is expected to increase program administrator requests for funding in 2012, which DRA will review.

Self Generation Incentive Program (SGIP)

In April 2011, CPUC staff issued a revised proposal, updating its recommendations to modify the ***Self-Generation Incentive Program (SGIP)*** to comply with ***SB 412 (Kehoe, 2009)***. DRA reviewed the CPUC staff proposal and found that the SGIP program should:

- Only support technologies with cost-effectiveness results that meet the societal Total Resource Cost (TRC) test (i.e., greater than 1.0 ratio of benefits to costs).
- Not utilize ratepayer dollars on emerging technologies that may never become cost-effective.
- Adopt a modest incentive decline to facilitate self-sufficiency and cost reductions in the market for SGIP technologies.
- Limit export of electricity from SGIP facilities to facilitate optimal and efficient sizing of distributed generation technologies.
- Provide different incentive allocations for different technologies so that a large portion of the available incentive money is not directed only to one or a few technologies.
- Determine if the current biogas premium of $2.00/W is justified.

What is it?

Senate Bill (SB) 412 (Kehoe, 2009): Required the CPUC to focus the Self-Generation Incentive Program (SGIP) on technologies that would reduce greenhouse gas emissions and determine, in consultation with the California Air Resources Board (CARB), which technologies should be eligible for the SGIP. The bill extended the funding for SGIP sunset date from 2012 to January 1, 2016. The CPUC subsequently began the redesign of SGIP with stakeholder input, which resulted in a 2010 CPUC staff proposal on program modifications.

SGIP Eligibility: Based on ability to reduce greenhouse gas (GHG) emissions. Eligible technologies include wind turbines, fuel cells, gas turbines, micro-turbines and internal combustion engines, organic rankine cycle/ waste heat capture, combined heat and power (CHP), advanced energy storage, and pressure reduction turbines. These technologies will receive upfront and performance-based incentives (PBI). However, PBI payments will be reduced or eliminated in years that a project does not achieve cumulative GHG reductions.

Incentives apply only to the portion of the generation that serves a project's onsite electric load.

- Not determine financial need based upon the ability to complete transactions with and without the SGIP.

In September 2011, the Commission rejected its staff's proposed eligibility requirement that technologies pass the cost-effectiveness test as a prerequisite to receiving SGIP incentives, noting that SB 412 does not contain such an eligibility requirement. DRA had advocated to the CPUC that SB 412 authorized the CPUC to consider more factors than just greenhouse-gas reducing capability of a technology when determining eligibility, including cost-effectiveness. The updated SGIP decision also directed:

- Emerging technologies may receive higher incentives than mature technologies regardless of cost-effectiveness.
- Hybrid Performance-Based Incentives (PBI) should provide 50% upfront payment and 50% PBI based on kWh generation of on-site load.
- Implementation of a declining incentive structure.
- Export of electricity from SGIP facilities to the grid limited to up to 25% of their annual output.
- Incentive structure should be differentiated according to fuel rather than just technology.
- Biogas premium will be maintained at $2.00/Watt.
- Out-of-state directed biogas will be excluded from SGIP eligibility.
- Financial need will not be a screen for SGIP eligibility.
- Stand-alone storage may participate in SGIP.

As the CPUC implements the updated SGIP, DRA will review requests for funding. Additionally, the CPUC is in the process of implementing AB 1150 (Perez, 2011), which authorized additional funding for SGIP up to $83 million per year for 2012 - 2014. DRA advocated that funding not be authorized to the full amount at this time, because the utilities already had collected substantial sums that had yet to be allocated and spent. A CPUC proposed decision issued in November 2011 would limit initial funding in 2013 to half of the annual cap at approximately $42 million. The proposal would also require a review of the program and its funding by the CPUC's Energy Division staff by March 15, 2013.

Feed-in Tariffs

In January 2011, the CPUC initiated a rulemaking to implement ***Senate Bill (SB) 32***.

WHAT IS IT?

SB 32: Amends §399.20 to create a 750 MW feed-in tariff program for small renewable energy generators up to 3 MWs in size. The subsequent passing of Senate Bill 2 1X amended the price provisions of §399.20 (d) by deleting references to the cost containment provision or market price referent of the existing RPS program. As a result, the CPUC opened Rulemaking R.11-05-005 to explore new pricing mechanisms for the Feed-in Tariff (FiT) program by conducting a review of different pricing mechanisms to comply with SB 32.

Feed-in Tariff (FiT): A rate structure that pays generators to produce electricity at a set price and guarantees a purchase price for that electricity for a set period of time.

Net Surplus Compensation Rate (NSC): Adopted in CPUC decision D.11-06-016, a pricing structure is made up of two components: 1) the CAISO hourly day-ahead electricity market price or "default load aggregation point" (DLAP) price; and 2) the value of the renewable attributes associated with the electricity.

The most contentious issue in implementing the ***Feed-in Tariff (FiT)*** program has been to determine how the tariff price should be calculated to attract interest from small renewable developers while adhering to the ratepayer indifference clause, §399.20(d)(3). Other issues have included whether to:

- Require former customers of programs such as the California Solar Initiative (CSI) and Net Energy Metering (NEM) to refund any incentives received before switching to a Feed-in-Tariff.
- Expand the program cap beyond the current 750 MWs cap.
- Allow facilities larger than 3 MWs to qualify for the tariff.

DRA proposed that the CPUC adopt a ***Net Surplus Compensation (NSC)*** rate for the SB 32 tariff price because such a pricing structure can provide a market price that meets all of the criteria of §399.20 (market based rate, avoided cost, and ratepayer indifference). As an established rate, NSC can be utilized now to fulfill the CPUC's goal to implement the program on an expeditious schedule.

DRA advocated that the CPUC require previous customers of CSI, NEM, or other customer-side programs who switch to the SB 32 FiT program to refund any ratepayer incentives and payouts received in order to prevent FiT participants from profiting from ratepayer subsidized programs. The CPUC should prioritize putting a refund structure in place before launching this phase of the SB 32 FiT program.

In 2011, the CPUC Energy Division staff issued a straw proposal which proposes to use the results of the utilities' first RAM auctions to set the SB 32 feed-in tariff price [see RAM, p. 40].

The CPUC expects to issue a proposed decision on the implementation of SB 32 by the first quarter of 2012.

Bear Valley Electric Biogas

Bear Valley Electric Service (BVES), a division of Golden State Water Company (GSWC), requested CPUC approval in 2010 for its Biogas Renewable Energy Project which would result in a ten-year contract with BioEenergy to purchase biogas produced from dairy farms in Fresno. BioEnergy, a developer of "cow power," entered into a bilateral contract with BVES to provide biogas. The project would be a component of BVES's Renewable Portfolio Standards (RPS) program.

What is it?

Market Price Referent (MPR): The Market Price Referent is a CPUC-established benchmark for renewable energy and is calculated based on the average cost of energy produced from a combined cycle turbine generator (CCTG). The MPR also includes a Greenhouse Gas adder.

DRA protested the project because BVES did not adequately demonstrate the availability and deliverability of the biogas to the BVES power generating facility. BioEnergy was unable to secure financing for the project and suspended its biogas operations. BVES then entered into a Biogas Option Agreement (BOA) with BioEnergy that would enable BVES to obtain biogas from BioEnergy once BioEnergy resumes operations in the future.

DRA reached a joint settlement with BVES's parent company GSWC in January 2011 and agreed on the following issues:

- BVES will withdraw its original request contingent upon CPUC approval of the contract between BVES and BioEnergy and then file a new request for its BOA.
- The future price of biogas that BVES pays will be equal to the lowest price of biogas BioEnergy offers to another purchaser.
- Any future BVES contracts will be subject to DRA support and CPUC approval.

DRA will support future delivery of biogas to BVES at a cost equal to or lower than the prevailing ***Market Price Referent (MPR)***. The use of biogas as a renewable energy option should be monitored closely because of cost, availability, and deliverability issues.

A CPUC decision on the settlement agreement is expected in 2012.

TRANSMISSION

CAISO Transmission Planning Process

In 2011, the process for planning transmission in California was renamed the ***Transmission Planning Process (TPP)***. This process covers all the transmission planning performed by the California Independent System Operator (CAISO), including planning for renewables. DRA represents ratepayers' interest in this process by participating in stakeholder meetings, reviewing transmission planning documents, and submitting written comments to the CAISO identifying issues to maximize ratepayer benefits. DRA provided feedback on the CAISO's 2011 TPP for its planning assumptions and study plan, analysis assumptions and proposed scenarios, and the results of the preliminary study report.

What is it?

Transmission Planning Process (TPP): Annually, the California Independent System Operator (CAISO) conducts its transmission planning process to identify potential system limitations and opportunities for system reinforcement to improve reliability and efficiency. The resulting product of the Transmission Planning Process is the CAISO Transmission Plan, which documents all activities identified or conducted during the planning cycle related to infrastructure development that impact the CAISO grid.

Talega-Escondido/Valley-Serrano Interconnect Project

In July 2010, The Nevada Hydro Company (TNHC) applied to the CPUC for a Certificate of Public Convenience and Necessity (CPCN) to build the Talega-Escondido/Valley-Serrano Interconnect Project. The project is a 30-mile long, 500-kilovolt (kV) link between Edison's existing Valley-Serrano 500-kV transmission line in western Riverside County and SDG&E's existing 230-kV Talega-Escondido transmission line in northern San Diego County. DRA is currently evaluating the project for need and cost and to determine whether viable and less-expensive alternatives may exist. In December 2011, the CPUC issued a notice proposing to dismiss the TNHC's request because of concerns regarding project funding and viability. DRA supports the November 2011 proposed decision to dismiss the request. No final action will be taken until 2012.

Alberhill Substation

In 2010, Edison proposed to construct the Alberhill system project in the Southern California Inland Empire for $318 million that would result in:

- 1,120 Megavolt Ampere (MVA) 500/115 kV Substation.
- 2 - 500 kV transmission line segments.

- Substation connection to the existing Serrano-Valley 500 kV transmission line.

Edison proposes that the Alberhill project is needed to address an identified future overload of the existing two 500 kV/115 kV transformers in the Valley Substation that feed the Valley South 115 kV System due to increased electrical demand on the Valley South 115 kV System.

DRA's initial evaluation shows that the Alberhill project is not needed because there are a number of lower cost alternatives. DRA's analysis also determined that Edison's justification for the project, based on Edison's load demand estimates for the existing lines, is not sufficient to justify the project. Edison should evaluate the lower cost alternatives.

The project is still in the California Environmental Quality Act (CEQA) recertification phase and cannot proceed further in the CPUC permitting process until that phase is complete, which is projected for March 2012.

Red Bluff Substation and Interconnection Project

In November 2010, Edison requested the CPUC to allow it to construct the Red Bluff Substation located in Tehama County, for a cost of $217 million. The purpose of the project is to interconnect a proposed 550-megawatt solar photovoltaic (PV) generation project, known as the Desert Sunlight Solar Farm (DSSF), with the CAISO grid. The DSSF project would be located on lands administered by the Bureau of Land Management (BLM).

In February 2011, DRA argued Edison should be required to file a CPCN because the project proposed to extend the 500kV transmission lines by more than two miles. DRA also expressed concern that without a CPCN review process, the project would not be subject to an expenditure cap. In July 2011, the Commission approved the Red Bluff Substation without requiring the CPCN.

Distributed Generation Interconnection Rules

In August 2011, the CPUC established a closed and confidential settlement process to update ***Rule 21***. Subsequently, the CPUC opened a proceeding to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources. The purpose of the proceeding is to address issues that may not be covered in the settlement process – or if the settlement process is unsuccessful.

DRA strongly supported development of a simplified interconnection procedure for distributed generators connecting to each investor owned utilities' distribution system. DRA recommended that the cost responsibility of the distribution system and network upgrades, if any, be assigned to the connecting generator.

The settlement process will continue into 2012. If the process is successful, additional broader issues will be identified and addressed in the CPUC's proceeding.

WHAT IS IT?

Rule 21: In 1998, the CPUC recognized the potential benefits of new energy technologies and the need to facilitate their potential. Accordingly, it initiated the development of Rule 21 on Jurisdictional Distribution System Interconnection tariffs. The CPUC worked with the California Energy Commission (CEC) to implement the new tariff. In 2000, the CPUC issued a decision, D.00-11-001, adopting Rule 21 for each of the investor-owned utilities.

Technological developments in energy generation resources (such as solar power, Combined Heat and Power, small natural gas turbines) provided an opportunity to more efficiently serve local load rather than bringing power from remotely located, large power plants. Due to the recent increase in the number and types of requests to interconnect under the Rule 21 tariff, the CPUC needed to update the tariff.

CLIMATE CHANGE STRATEGIES

Greenhouse Gas (GHG) Cap & Trade Program

In July and September of 2011, the ARB issued draft changes to the Greenhouse Gas (GHG) Cap & Trade proposed regulation, including a delay in enforcement of the ***Cap-and-Trade program*** until 2013, with the first auctions for ***GHG Allowances*** beginning in August 2012. The final ARB Cap-and-Trade regulation was adopted in October 2011. The California utilities will be required to comply with the program by turning in GHG allowances to the ARB for each ton of carbon dioxide equivalent (MT CO_2e) they emit.

DRA estimates that the revenues generated from the sale of GHG emissions allowances freely allocated to the utilities by the ARB in 2013 could be more than $970 million.

Revenues Generated could exceed
$970 MILLION

WHAT IS IT?

AB 32 (Nunez, 2006) - The California Global Warming Solutions Act of 2006: Requires statewide reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 grants the California Air Resources Board (ARB) broad authority to regulate GHG emissions to reach this target. As part of its 2008 Scoping Plan that recommends specific programmatic measures to achieve these emission reductions, the ARB developed a statewide cap-and-trade program. In 2010, the ARB released a detailed proposed regulation to Implement the California Cap-and-Trade Program (proposed regulation), and adopted it on December 16, 2010.

Cap-and-Trade Program: The program California has chosen to meet AB 32 emissions reduction target. The ARB will place a cap on GHG emissions from sources responsible for approximately 80 percent of California's GHG emissions. The ARB will issue a limited number of tradable GHG allowances equal to the cap and over time, the cap will steadily decline and eventually reach a level in 2020 designed to ensure that California achieves the AB 32 target. The Cap-and-Trade program is designed to provide covered entities flexibility to seek out and implement cost-effective options to reduce emissions. GHG Compliance Products include:

- **GHG Allowances** - ARB will create one GHG allowance for each ton of GHG emissions covered by the declining cap.
- **GHG Offsets** – Reduction projects that occur in areas outside the covered sources such as forestry, livestock manure projects, or ozone depleting substances (ODS) projects. GHG offsets can be used for up to 8 percent of an entities' compliance obligation.

In order to support optimal policy outcomes in the state's efforts to mitigate the effects of GHG and to protect customers, DRA advocated for:

- **GHG Procurement Upfront Standards and Strategies**: The utilities' procurement plans for GHG products should ensure the utilities can comply with the ARB's Cap-and-Trade program while protecting ratepayers and managing the price risk of GHG.
- **Economic Effects of Reducing GHG Emissions:** The CPUC should undertake an analysis that captures the overall economic effects of GHG emission reductions as opposed to buying GHG compliance products each year.
- **Revenues Generated from the Sale of GHG Emissions Allowances:** The utilities return 90 percent of the GHG revenues, freely allocated to the utilities by the ARB, directly to customers whose rates increase due to the Cap-and-Trade program. This would illustrate the program's success to customers by mitigating their electricity bills in the form of annual rebates or annual bill reduction. The utilities could also use the opportunity while returning funds to inform customers about the Cap-and-Trade program, including steps they can take to further reduce their GHG emissions and their electric bills.
- **Consolidated Financing Program:** The remaining ten percent of the GHG revenue should be used to fund the "Consolidated Financing Program," a mechanism that would finance energy efficiency improvements. The purpose of the financing program would be to fund, develop, and implement a variety of financing mechanisms to leverage the capital raised from customers with private capital that would result in low interest loans for energy efficiency projects. This strategy would address a significant market barrier to implementing energy efficiency improvements that are currently too costly for most customers. In addition, DRA proposed that a portion of the remaining ten percent of the GHG revenue should be used for administrative expenses associated with the allowance rebate.

DRA expects a decision regarding the utilities' plans for procurement of GHG products in early 2012 and a decision in May 2012 regarding the use of revenues generated from the sale of GHG emissions allowances freely allocated to the utilities by the ARB.

Qualifying Facilities: Combined Heat & Power

In December 2010, the CPUC approved the ***Qualifying Facility(QF) / Combined Heat & Power (CHP)*** settlement agreement conditioned upon: 1) a final and non-appealable CPUC decision approving the settlement agreement; and 2) a final and non-appealable Federal Energy Regulatory Commission (FERC) order approving a Joint Utilities Application to terminate the mandatory ***Public Utilities Regulatory Policies Act (PURPA)*** purchase obligation for Qualifying Facilities (QFs) greater than 20 MW.

What is it?

Public Utilities Regulatory Policies Act (PURPA): PURPA was enacted in 1978 to stimulate the use of alternative and renewable energy sources for the conservation and efficient production of electricity. In 2005, regulations governing utilities' obligation to purchase electric energy produced by ***Qualifying Facilities (QFs)*** were revised to allow electric utilities to seek exemption from the mandatory purchase obligation of QF power under certain market conditions.

Qualifying Facilities (QFs): An electric energy generating facility under Federal Energy Regulatory Commission (FERC) jurisdiction whose excess power must be purchased by the utilities at the avoided cost. The determination of "avoided cost" is delegated by the FERC to the CPUC. Qualifying Facilities fall into two categories: cogeneration facilities and qualifying ***small power production facilities***.

Combined Heat and Power (CHP): Combined Heat and Power system or cogeneration means the sequential use of energy for the production of electrical and useful thermal energy.

Small Power Production Facility: A generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind, or solar), biomass, waste, or geothermal resources.

ARB Scoping Plan: Proposes a comprehensive set of actions designed to reduce overall carbon emissions in California, including an increase of 4,000 MW of CHP capacity by 2020.

In June 2011, FERC granted the request of a group of California stakeholders, including DRA, to terminate the mandatory purchase obligations of Edison, PG&E and SDG&E pursuant to PURPA for QFs with a net capacity in excess of 20 MW. The FERC order is now final and non-appealable.

Because these two condition precedents have been met, the settlement agreement has an effective date of November 23, 2011. The settling parties have now begun implementing the agreement by withdrawing QF-related disputes in various forums before the CPUC, FERC, and the Court of Appeals.

DRA supported the comprehensive QF/CHP settlement agreement because California consumers will benefit as energy costs will eventually move from the utilities' avoided cost to a viable market based compensation for QFs. Consumers also benefit from the environmental benefits since the settlement agreement follows the direction of the ***ARB Scoping Plan***, which proposes an increase of 4,000 MW of CHP capacity by 2020 to reduce overall carbon emissions in California.

Under the settlement, California's investor owned utilities will still be obligated to purchase QF power under 20 MW net capacity under Standard Offer Contract pricing. The QF/CHP settlement agreement establishes:

- A Combined Heat and Power (CHP) procurement target of 3,000 MW by 2015.
- Creates three rounds of CHP-only Request for Offers (RFO) during the initial program period.

This sets an "orderly transition" for QFs over 20 MW to a state CHP program as a replacement to the standard offer contracts under the federal PURPA program. It also establishes a bridge for existing expired, or expiring, CHP contacts to continue to operate by:

- Participating in the CHP-only solicitation process.
- Executing one of the applicable pro-forma contract options developed through the settlement.
- Exiting from the utility QF contracts.

The settlement agreement further establishes a benchmark for Greenhouse Gas (GHG) benefits and resolves pending CPUC cases and court litigation concerning mainly retroactive pricing claims. The settlement aims to move to a viable market based pricing for QFs, secure cost-effective GHG reductions, and complement other existing state policy programs that reduce GHG emissions.

Plug-in Electric Vehicles (PEVs)

In 2011, the CPUC continued to implement ***SB 626 (Kehoe, 2009)*** with a second phase to address policies and develop rules to overcome barriers to the widespread deployment of electric vehicles, costs, and rate design. In Phase 2, DRA advocated for the fair treatment of all ratepayers as the utilities upgrade their facilities and establish rates for ***Plug-in Electrical Vehicle (PEV)*** charging, including:

- Policies that balance the needs of both PEV owners and other ratepayers.
- Offer PEV owners dual metering (***separate*** or ***submeter***).
- Rates which are higher during peak hours and lower during off-peak.
- Utility ownership of separate meters dedicated to PEV loads.
- Utility analysis in order to assess the impact of PEV charging on the system.

WHAT IS IT?

SB 626 (Kehoe, 2009): Requires the CPUC to evaluate policies to overcome barriers to widespread deployment of plug-in hybrid and electric vehicles. The CPUC initiated the Plug-in Electric Vehicle (PEV) proceeding in 2009 to consider alternative-fueled tariffs, infrastructure, and policies to support California's greenhouse gas emissions reduction goals as well as to ensure investor-owned electric utilities are prepared for the market growth of light-duty passenger plug-in hybrid proceeding. In 2010, the CPUC issued D.10-07-044 which determined that the CPUC has the authority to regulate the impact of PEVs in achieving the state's greenhouse gas goals, but not to regulate electric vehicle charging services as public utilities.

PEVs: Refers to both Plug-in Hybrid Vehicles that run on both electricity and gasoline, as well as Battery Electric Vehicles that run on electricity only.

Submetering: A meter located on the owner's premises or a PEV which can measure the PEV usage and is placed on the same line as the main residential meter.

Separate Metering: A meter that is placed on a separate service line from the main residential meter.

Electric Vehicle Charging Equipment

- CPUC should determine the amount of allowance for PEV owner required upgrades, based on the load impact analysis.
- Proceeding should remain open to address the unresolved and ongoing issues.

The CPUC adopted the Phase 2 PEV decision in July 2011 addressing such issues as infrastructure upgrades, metering arrangements, cost responsibility, and applicable rates. The decision incorporated all of DRA's above recommendations.

DRA will continue to actively participate in the CPUC's upcoming PEV proceedings which will address:

- Development of methods of measuring PEV power usage separately from the house measurements and utility billing systems for PEV's energy usage.
- Conducting of research and analysis to determine customer charging behavior, pattern, and its load impact.

The CPUC plans to have a decision on these PEV issues by January 2013.

DEMAND-SIDE MANAGEMENT

Energy Efficiency

Utility Shareholder Risk-Reward Incentive Mechanism

In August 2011, the CPUC issued a ruling stating that the CPUC's energy efficiency ***shareholder incentive mechanism***, which commenced in 2006, has "channeled resources largely into procedural disputes over process and measurement protocols," instead of into greater innovation and the pursuit of greater energy savings. This ruling followed a contentious process during the 2010-2012 program cycle to establish the foundational data required for determining shareholder incentives, which resulted in an 18-month delay in finalizing ***ex ante assumptions***. The CPUC requested that stakeholders provide feedback to reevaluate the mechanism.

WHAT IS IT?

Risk Reward Incentive Mechanism (RRIM): A mechanism designed by the CPUC to incentivize superior energy efficiency performance by the state's four largest investor owned utilities. The reward, subsidized by ratepayers, is intended to overcome the utilities' inherent bias towards building of power plants.

Ex Ante Assumptions: Energy savings assumptions for each technology based on market data and past program evaluations that are utilized at the beginning of an energy efficiency program cycle to estimate the amount of energy that will be saved by a program.

DRA urged the CPUC to eliminate the failed risk/reward incentive mechanism for energy efficiency programs, demonstrating that there is no correlation between shareholder bonuses and superior energy savings achieved by utility energy efficiency programs. Instead, the incentive program to date has resulted in undeserved awards to the utilities of over $270 million dollars. In December 2011, the Commission awarded $60 million of those bonuses based on largely utility self-reported and unevaluated energy savings. Energy Efficiency programs have not been cost-effective, thus ratepayers paid more for energy efficiency than they received in energy benefits.

Rather than attempting to fix the mechanism, DRA urged the CPUC to change program management from investor owned utilities to an expert non-profit with core competence in transforming markets because of the utilities':

- Poor track record in achieving Energy Efficiency goals.
- Lack of ability to be nimble and adaptable to the market.
- Inherent conflict of interest between energy efficiency program goals with the goals of the utilities' core business.

The CPUC is expected to issue a proposed decision in early 2012.

Evaluation, Measurement, and Verification

In 2009, the CPUC issued a decision, which set the course for 2010-2012 energy efficiency programs, ordering that ***ex ante* values** would be frozen during that program cycle. These *ex ante* values would be established using the best available information and incorporated from the start of the cycle. The utilities subsequently requested the CPUC allow them to utilize their own forecasted values rather than using the CPUC's independently established values, as the Commission had previously ordered.

> ### WHAT IS IT?
>
> **Ex Ante Values**: Energy savings assumptions by technology used to forecast program energy savings based on market data and past program evaluations in order to most accurately predict energy savings that will result from an energy efficiency program.
>
> **Net-to-Gross Ratios (NTG):** A factor used to determine the amount of energy savings directly attributable to utility energy efficiency programs, excluding energy savings from customers who would have participated with or without program subsidy. Also known as "freeriders."
>
> **Custom Projects:** Energy Efficiency measures and projects that are developed based on an ***ex ante*** unique site-specific, project-by-project basis and do not rely upon fixed or standard values. Ex ante values, therefore, cannot be fixed until the project is identified.
>
> **Gross Realization Rates:** A multiplier that attempts to take into account the likelihood that not all CPUC-approved projects undertaken by utilities will come to fruition.
>
> **High Impact Measures (HIMs):** Energy Efficiency technologies that contribute to greater than 1% of portfolio savings.

DRA's analysis revealed that the utilities tend to use outdated or overstated assumptions to forecast their energy savings from Energy Efficiency programs. As a result, these assumptions often artificially inflate utility achievements from the programs. DRA advocated that *ex ante* values should:

- Use updated ***Net-to-Gross (NTG)*** values determined by the CPUC evaluation of 2006-2008 Energy Efficiency programs, rather than utility default values, which may be inflated and not reflect actual program savings.
- Apply specific standards for program measures that are replaced before the end of their useful lives.
- Apply a 20% discount to ***custom projects*** that cannot be reviewed meaningfully by CPUC evaluation based on the projects' past performance (***Gross Realization Rates***).
- Allow CPUC staff to review ***custom projects*** that utilities report to have high impact of more than 1% impact on portfolio savings.

In July 2011, the CPUC issued a decision which recognized that the utilities essentially were requesting to eliminate the CPUC staff approval process because it would result in a utility "veto" whenever they disagreed with CPUC staff review. The CPUC decision adopted:

- The most up-to-date default values for *Net-to-Gross ratios*.
- Final determination by CPUC staff for certain ***High Impact Measures (HIMs).***
- A 10% discount (or a 90% Gross Realization Rate) for projects that cannot be reviewed by CPUC staff.
- A dual baseline for early retirement measures, that is, technologies that are replaced before their useful life has been reached.

These *ex ante* values, which were intended to be used at the beginning of the 2010-2012 Energy Efficiency program cycle to forecast energy savings, were not adopted until 18 months into the program cycle.

While the CPUC's decision does not go far enough to protect ratepayers, because it continues the use of many of the energy savings assumptions (***net-to-gross ratios, gross realization rates, HIMs***) for 2010-2012 programs that are outdated, inflated, and unreviewed, it is a step in the right direction as it adopts some standards and reductions that protect ratepayers from inflated forecasts.

2013-2014 Transition-Funding

In 2011, the CPUC determined that there may not be sufficient time to complete the foundational studies it needs to launch the next Energy Efficiency program cycle which was due to commence in January 2013. Such studies include:

- Updates to Energy Efficiency potential estimates which provide the basis for setting savings goals.
- Improvement to cost-effectiveness tests.
- Development of criteria for setting market transformation standards.

Given that current Energy Efficiency program funding is authorized only through 2012, the CPUC is investigating whether two transition years of funding is necessary in order to make those improvements. The CPUC established a proceeding for the purpose of determining the conditions for the transition years.

DRA supports transition-year funding as necessary to making program improvements in order to better utilize ratepayer dollars and maximize savings from energy efficiency investment. DRA recommended the following program improvements before commencing the next Energy Efficiency program cycle:

- Cap the annual transition period budget to $900 million.
- Provide a Consolidated Financing Program with 5-year annual seed funding of at least $150 million from the $900 million administered by the California Alternative Energy and Advanced Transportation Authority (CAEATFA).
- Eliminate all upstream rebates for basic compact fluorescent lighting and significantly reduce appliance recycling, which are no longer needed.
- Utilize the best available, up-to-date market data to develop programs, which demonstrates actual need in the marketplace.
- Establish regionalized local government pilot programs to promote partnerships and innovation among local government energy leaders.

DRA advocated for transitional period funding that will lead to significantly improved energy efficiency program administration by 2015. A CPUC proposed decision is expected in early 2012.

Demand Response

2012-2014 Demand Response Programs

In March 2011, the utilities requested CPUC approval of their ***Demand Response (DR)*** programs, activities, pilots, and budgets for the years 2012 through 2014 that total over $1 billion, including customer incentives. DRA supports Demand Response programs as an essential element of California's resource strategy, yet advocated in 2011 that the CPUC should only approve Demand Response programs that are cost-effective and meet the "just and reasonable" standard.

WHAT IS IT?

Demand Response (DR): The load reduction or increase by retail customers in response to a signal or pricing mechanism. The CPUC's 2005 Energy Action Plan II directed utilities to procure cost-effective **"**preferred" resources such as energy efficiency and Demand Response, before acquiring any new conventional generation resources.

DRA's analysis of the utilities' proposed Demand Response programs found:

- Many programs are not cost-effective, with benefit/cost ratios significantly below 1.0 (the minimum value for being cost-effective) using the CPUC's pre-established methodology that tests for cost-effectiveness from various perspectives including environmental benefits and locational value.
- In particular, PG&E's Aggregator Managed Program (AMP) contracts are significantly not cost-effective, with benefit/cost ratios below 0.5.
- PG&E's AMP contracts have been ineffective in the previous program cycle.

The CPUC issued a proposed decision which was largely favorable to ratepayers, but sets a threshold for Demand Response program eligibility slightly below the required cost-effectiveness benefit/cost ratio of 1.0. The proposed decision also required the programs meet this lower benefit/cost ratio of 0.9 for only two of the three prescribed cost-effectiveness tests. The proposed decision rejected PG&E's request to extend the AMP contracts unless contracts could be modified to meet this new cost-effectiveness standard.

DRA opposes spending ratepayer dollars on Demand Response programs that are not cost-effective and urged the CPUC to return to the minimum cost-effectiveness benefit/cost ratio of 1.0 in the next DR program cycle. Additionally, DRA urged that a reduced cost-effectiveness threshold for DR in this cycle should not influence the cost-effectiveness minimums for other programs, such as Energy Efficiency.

However, at a CPUC business meeting in December 2011, certain commissioners signaled their interest in developing an alternate proposal for future Demand Response programs. The alternate proposal is expected to be issued in early 2012.

Edison Summer Discount Plan Air Conditioning Cycling Program

In 2010, Edison submitted an expedited request to the CPUC for its Summer Discount Plan (SDP) for ***Air Conditioning (AC) Cycling*** Program, proposing to revise its SDP to transition customers from a rarely-used emergency program to a frequently-used price-responsive Demand Response program, as ordered by the CPUC. Edison proposed to offer approximately 330,000 existing customers the option to choose a new override-enabled Air Conditioning (AC) Cycling switch for the program, for an additional program cost of $26 million. The revised program allows customers to opt-out of SDP for up to five times per year.

> **WHAT IS IT?**
>
> **AC Cycling**: In response to a Demand Response event, the participating customer's Air Conditioning (AC) unit is remotely turned on and off, intermittently, by the utility to decrease the load on the utility's grid. In a 100% cycling option, for example, the customer's AC unit is turned off completely during the DR event, usually lasting from 2 to 6 hours. In a 50% cycling option, the customer's AC unit is turned off 15 minutes in each 30 minute period during the DR event.

DRA opposed the new override switch option because it would:

- Create several million dollars in stranded costs for ratepayer investment in the existing AC Cycling switches.
- Lead to significantly less Demand Response during periods of peak demand due to the generous opt-out provision, which would require additional procurement for replacement of the Demand Response.
- Continue high level of unneeded customer incentives (approximately $200 per summer) for customers choosing the 100 percent cycling option.

> **COSTLY OVERRIDE SWITCH**
>
> **May Result in Stranded Costs and Duplicative Costs to Replace Lost Capacity**

Instead, DRA proposed that Edison model its SDP program after PG&E's successful AC Cycling program (SmartAC) that offers a small, one-time customer incentive as a signing bonus. Given that Edison has already signaled its plans to implement, in the next couple of years, a new technology to work in coordination with its smart meters, Edison would have to replace the new override switches, leaving additional, unnecessary costs stranded for customers. Accordingly, until the new technology is available, DRA asserted that Edison's current technology is sufficient and has proven successful in handling customer requests to opt-out of a Demand Response event in rare cases when customers utilize it.

In November 2011, the Commission approved Edison's request to implement the new over-ride switches, but supported DRA's recommendation to review the progress of the program in one year.

Edison has also requested an additional $71.1 million to continue to implement this non-cost-effective program as part of its 2012-2014 Demand Response program portfolio.

Direct Participation in CAISO Market

As part of the CPUC's effort to implement ***Federal Energy Regulatory Commission (FERC) Order 719*** requiring ***Demand Response providers*** to bid into the CAISO market, it has undertaken development of additional comprehensive policy rules. The CPUC has proposed Rule 24, which would govern the various relationships between the CAISO, Demand Response

> **WHAT IS IT?**
>
> **Federal Energy Regulatory Commission (FERC) Order 719:** In 2008, FERC issued the order requiring Independent System Operators to modify their tariffs to allow retail customers to bid Demand Response ("DR") directly into these markets, on their own behalf or through aggregators. This will allow DR resources to be considered on the same basis as conventional generators. In 2010, the CPUC responded to the FERC ruling by issuing decision D.10-06-002 to establish conditions under which the CPUC will oversee retail DR bidding participation with the California Independent System Operator (CAISO). The CAISO has also developed specific market products appropriate for DR bidding.
>
> **Demand Response Provider (DRP):** An entity providing Demand Response service to the CAISO through retail customers within IOUs' territory.

providers, the investor owned utilities and their bundled customers, Energy Service Providers (ESPs) and their Direct Access (DA) customers, and Community Choice Aggregators (CCA) and their customers. Each of these stakeholders would play a role in bidding retail customer load into the CAISO markets.

The CPUC issued a draft of proposed Rule 24, requesting stakeholders comment on its proposal addressing:

- Regulatory coverage of DR providers, including those serving large commercial and industrial customers.
- Customer privacy standards and protection, including customer permission and access to and use of customer data.
- Process by which customer participation in DR programs should be tracked.

DRA advocated for more comprehensive consumer protections than those proposed in the CPUC's draft Rule 24:

- Customer privacy standards and protections should be consistent with smart grid privacy rules defined by CPUC decision.
- All DR providers should be required to register and post a bond with the CPUC.
- The CPUC should assert strong oversight of retail DR direct bidding participation with respect to customer privacy; customer complaints; and communication protocols between DR providers, retail customers, Load Serving Entities (LSEs), and other issues arising from customer complaints against DR providers.
- The CPUC should first rule on several policy issues before developing and adopting a final Rule 24, including Rule 24's applicability to DR providers and other parties, customer privacy, information flow, registration of DR providers with the CPUC, penalties for fraud and non-performance, and rules governing financial settlements between various parties.

A CPUC decision has been delayed until FERC issues a final order clarifying the direct participation rules in organized markets.

Demand Responsive Pricing

DRA Report: Time-Variant Pricing for Residential and Small Business Customers

In May 2011, DRA published a white paper entitled ***"Time-Variant Pricing for California's Small Electric Consumers."*** In this paper, DRA undertook research to determine how the CPUC

What is it?

Time-variant Pricing: In response to reliability concerns stemming from the 2000-2001 California Energy Crisis, California's Energy Action Plan II called for "well-designed dynamic pricing tariffs" for all customer classes. Following this policy directive, CPUC decision D.08-07-045 concluded that: "***TOU*** with ***CPP*** should be the default rate for medium [Commercial & Industrial] and small commercial customers." CPUC rate design directives have yet to be implemented for small customers.

Time-of-Use (TOU): A rate in which the price of electricity varies by preset usage periods (e.g., by time of day, day of the week, and season).

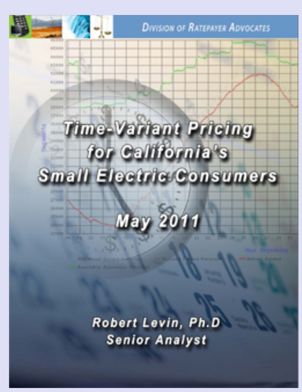
Critical Peak Pricing (CPP): A rate that features a short term price increase to a preset level when triggered by real-time system conditions. The timing of such CPP events is known only 24 hours in advance.

Dynamic Rates: *Rates are allowed to vary frequently to reflect market/electric system conditions.*

Real-Time Pricing (RTP): A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.

Peak Time Rebate (PTR): A utility bill rebate is determined by comparing a customer's kWh usage during a peak event with a customer's actual usage during a specific period of time prior to the peak event period. If the customer's usage during the peak-event period is less than the customer reference level, the customer qualifies for a rebate.

DRA's White Paper *Time-Variant Pricing for California's Small Electric Consumers:* Can be found on DRA's Website at: http://www.dra.ca.gov/DRA/Energy/Customer+Rates/Rate+Design/tou_paper.htm



can best achieve state energy policy objectives through transitioning small electric consumers to time-variant pricing.

DRA's Report found that compared with ***Critical Peak Pricing (CPP)***, ***Time-of-Use (TOU)*** pricing is more likely to:

- Be understandable.
- Place fewer burdens on customers so that more customers are likely to participate.
- Out-perform CPP rates in reducing greenhouse gas emissions.
- Produce more dollar value benefits for small electric consumers when combined with technology investments.
- Encourage investment in energy efficiency, a major factor in achieving California energy policy goals of reducing GHG emissions and controlling cost.
- Make California's electric system more efficient and hold down future increases in electricity costs by increasing electric system load factors.
- Aid residential and small business customers by slowing the growth of utility revenue requirements and moderating rate increases.

There is a trade off between Time-of-Use rates and Critical Peak Pricing rates in that CPP rates necessarily limit the size of the summer on-peak rate, which reduces the amount of load shifting on non-critical peak summer days.

DRA Study Finds
TOU MAY BE SUPERIOR
Pricing Scheme

The key recommendations of DRA's Report are:

- The CPUC should only implement default time-variant-pricing rates for residential customers using default TOU rates.
- TOU rates should be the default for most residential and small commercial customers only after a reasonable transitional period, if they comply with the rate protections provided by California statute.
- TOU rates should ultimately recover most marginal capacity costs in the peak (especially summer on-peak) periods.
- ***Dynamic rate*** designs (CPP and/or RTP) should be offered to residential and small commercial customers only on a voluntary opt-in basis.
- The CPUC should implement a residential Peak-Time Rebate (PTR) program to achieve demand response benefits of CPP that are incremental to those provided by TOU rates.
- Transition to time-varying rates should include adequate customer outreach and education, including solutions for energy savings programs.

These recommendations and objectives should be pursued only insofar as they avoid economic harm to vulnerable subgroups of residential ratepayers, including low-income households and households with special medical needs.

Critical Peak Pricing for Non-Residential Customers

In July 2010, SDG&E filed a request with the CPUC seeking $118 million to implement default ***Critical Peak Pricing (CPP)*** rates for its small business customers and optional CPP for residential customers, starting in 2013. DRA advocated for a gradual transition to ***time-varying rates***, starting with optional ***Time-of-Use rates (TOU)***, which is a more consumer friendly form of time-varying rates, and prior to implementing default CPP rates. DRA asserts that:

- Smart-meter enabled time-varying rates should be introduced to customers in a manner that promotes education and customer preparedness.
- Only reasonable funding should be approved to implement this rate option.

DRA performed a rigorous analysis which demonstrated that SDG&E's $118 million cost request was unreasonable and that SDG&E's plans for the dynamic pricing programs were not cost-effective.

$25 million
Savings DRA negotiated for SDG&E customers

DRA, SDG&E, and other parties reached an all party settlement in June 2011. The major features of the settlement include:

- SDG&E may recover up to $93 million for program implementation.
- SDG&E will gradually transition its customers to dynamic pricing programs by starting with more consumer-friendly, time-varying rate options prior to moving to default Critical Peak Pricing.
- Customer outreach and education mechanisms, bill protections, and additional terms to protect vulnerable customer groups.

The settlement was filed with the CPUC in June 2011 and parties are awaiting a proposed decision by the CPUC.

CONSUMER PROTECTION

Low Income Assistance Programs

In 2011, California's four largest investor owned utilities (PG&E, Edison, SDG&E, and SoCalGas) and the six small and multi-jurisdictional utilities (SMJUs) submitted proposals to the CPUC to approve their $4.8 billion 2012-2014 Low-Income assistance programs. The Low-Income assistance programs consist of: the ***California Alternate Rates for Energy (CARE)*** and the ***Energy Savings Assistance Programs (ESAP)*** which provide energy efficiency measures to eligible customers at no cost.

In April 2011, DRA requested that the CPUC defer making a decision on the Low-Income programs until improvements could be made to the utilities' program designs that would deliver more meaningful benefits to customers, as well as improved energy savings towards California's climate change goals. The CPUC granted DRA's request in September 2011.

In December 2011, the CPUC removed from the CPUC calendar hearings for the Low-Income assistance programs, originally scheduled to begin January 3. DRA had previously asserted that holding hearings are essential to improving the programs. A final decision is expected in April 2012.

CARE: California Alternate Rates for Energy Program

The utilities requested the CPUC authorize a statewide $1.2 billion *annual budget* to provide an energy rate discount to more than 5 million low-income customers through the ***California Alternate Rates for Energy (CARE)*** program. This amounts to an average annual discount of $240 per eligible customer. On a statewide basis, the annual cost of administering the program would increase from approximately $23 million to $28 million. Edison is the

WHAT IS IT?

California Alternate Rates for Energy (CARE): CARE provides a minimum 20% discount on energy and gas bills and exemption from the higher tier electricity rates. The utilities must offer bill these discounts. About one in three California households statewide qualify for CARE (4 million out of 12 million). The average savings for CARE customers ranged from $335 to $550 annually in 2010 93% of qualified households are enrolled in CARE.

Categorical Eligibility: Criteria by which households can qualify for CARE and ESAP by already being pre-qualified in one of several other 'approved' public assistance programs, e.g., Food Stamps,; Temporary Aid to Needy Families/Aid to Families with Dependent Children (TANF/AFDC); Women, Infants & Children (WIC), etc.

only utility that did not propose to increase administrative costs. Program participation is forecasted to increase nominally, except for SDG&E which projects a 13% increase.

DRA recommended the CPUC:

- Deny utility requests to increase outreach costs since enrollment has plateaued.
- Deny utility requests to preemptively eliminate ***categorical eligibility***, for both CARE and ESAP since it is a valuable enrollment strategy.
- Conduct workshops on low-income eligibility standards to incorporate results of the 2010 U.S. Census and to ensure program qualification of categorical eligibility programs are reasonably well-aligned with CARE standards.

Energy Savings Assistance Program (ESAP)

The utilities requested the CPUC authorize $1 billion for program years 2012-2014 in order to provide 1.2 million low-income households with energy efficiency services through the Energy Savings Assistance Program (ESAP). As proposed, eleven percent of the budget would be spent on administrative expenses and the balance would be allocated to contractor services, energy efficient appliances and materials, and inspections.

DRA's analysis shows that:

- Administrative costs would rise 43% from the prior cycle, for all utilities, to about $35 million annually.
- Program costs would increase 31% (Edison is lowest at 8%) to $300 million annually.
- Energy savings would increase program-wide by 17% (kWh), 25% (KW), and 7%(therms).
- Energy savings per household would essentially remain unchanged at 6% (kWh), 30% (KW), and 2% (therms).
- Edison projects per household electric savings to decrease 25%.
- SoCalGas is the only gas utility that projects an increase in therms.

DRA recommended that the 2012-2014 Low-Income programs should be modified and designed to increase bill savings at the household level.

- All ESAP households should receive tangible bill saving measures such as increased Lighting, Hot Water Reduction, and Refrigerator Replacement if the existing appliance is older than 2001.
- Households should demonstrate the potential to save 4% energy relative to their average CARE electric usage, in order to be eligible to receive ESAP services other than tangible bill savers.

Bill Savers Approach May

AID WITH AFFORDABILITY GAP

Non-energy benefits flow from bill and energy savings, so any increase in bill savings will drive an increase in non-energy benefits. DRA's recommendations will likely decrease weatherization work. Accordingly, resulting budget savings should be reinvested in the incumbent ESAP workforce through retraining in more skilled jobs that serve the ESAP.

Small and Jurisdictional Utilities

The ESAP proceeding also includes Small and Jurisdictional Utilities (SMJUs). These are six small and multi-jurisdictional utilities, which are required every three years to apply to renew their low-income rate discount (CARE) and energy efficiency (ESAP) programs. The SMJUs submitted their 2012-2014 program plans in summer 2011. Because the CPUC's review will extend into 2012, their programs will continue at current funding levels in 2012.

DRA protested the SMJU's program applications on the basis that policy decisions regarding the SMJUs' low-income programs be determined after policy decisions on the large utilities' low-income programs, and then SMJU programs be required to mirror those decisions. SMJU program approval is tentatively scheduled to occur concurrently with the CPUC's decision on the large utilities.

Energy Service Disconnections

In 2011, the CPUC continued its deliberation of energy service disconnection protections with a Phase 2 proceeding which focused only on Edison and PG&E residential customers. The CPUC had determined in 2010 that SDG&E and SoCalGas would be exempt from the proceeding because their customers are currently protected under a settlement agreement with DRA and other consumer groups through 2013. DRA has advocated that Edison and PG&E should extend similar protections to their customers.

What is it?

DRA's 2009 report on the *Status of Energy Utility Service Disconnections in California* identified disconnections on the rise, most significantly in PG&E's service territory. The 2009 report influenced the CPUC to open a proceeding on disconnection issues. The outcomes of that proceeding required the utilities to implement short-term measures such as terms to pay off customer debt and credit deposit waivers. The 2009 report also set the stage for SDG&E and SoCalGas to reach a settlement agreement with DRA and other consumer advocacy groups, which was subsequently approved by the CPUC. The settlement resulted in customer protections through a best practice approach by SDG&E and SoCalGas including:

- A benchmark for low annual disconnection rates of less than approximately 4% of all customers.
- Disconnect moratoriums on extremely hot or cold days.
- Consumer-friendly remote disconnection protocols.
- Utility in-person visits or phone calls prior to disconnections.

In February 2011, PG&E requested $3.9 million in ratepayer funds to distribute through its emergency disconnection prevention fund, Relief for Energy Assistance through Community Help (REACH). DRA supported the plan on the condition that ratepayer funds were matched 1:1 with shareholder funds and that PG&E would track the impact on reducing service disconnections. The CPUC's June 2011 decision approved the program. PG&E disbursed approximately $360 each to 3,500 low-income customers in need of emergency assistance, as of the third quarter of 2011.

DRA recommends that all California utilities should:

- **Set Disconnection Benchmarks:** **Edison:** Disconnect no more than 6% of low-income customers annually **PG&E:** Disconnect no more than 5% of low-income customers annually (as of October 2011, Edison had disconnected 8.4% and PG&E had disconnected 5.6% of its low-income customers, in the previous 12 months).
- **Expand the Definition of 'Vulnerable' Customer:** Require that those entitled to, receive a field visit prior to disconnection and offer a payment opportunity at that time for vulnerable customer groups of customers aged 62 and older, customers with disabilities, and customers with serious illnesses.
- **Allow Flexibility for Customers:** Customers should be able to choose their billing date without a fee.
- **Not Recover Credit and Collection Costs Outside of their General Rate Cases:** The CPUC should uphold its previous determination that utility costs recorded in special disconnection accounts will be considered in each utility's general rate case.
- **Implement a Customer Outreach Campaign:** Prior to using remote functionality to disconnect customers.

These recommendations are currently being considered in the Disconnection proceeding. In October 2011, the CPUC suspended the advent of Edison remote disconnections until issues regarding remote disconnection policies are resolved. In December 2011, the CPUC also extended the current protections for Edison and PG&E customers into 2012 until the CPUC can more fully address the issues in the proceeding.

DRA Report: Status of Energy Utility Service Disconnections in California

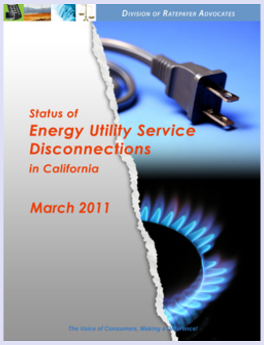
In March 2011, DRA issued its second report on the *Status of Energy Utility Service Disconnections in California.* The updated report sought to determine whether the short-term measures implemented by the CPUC in 2010 had been effective. DRA found that the discrepancy between the cost of energy and available assistance is significantly wide and that short-term measures cannot compensate for the **Affordability Gap.**

What is it?

Affordability Gap: The difference between *actual* energy costs and *affordable* energy costs.

Energy Burden: The cost of electric/gas/other heating fuel as a percentage of household income.

Energy Insecurity: More frequent losses of electric and gas service due to inability to pay bills makes a household more energy insecure.



DRA's Report can be found at: http://www.dra.ca.gov/DRA/energy/Customer+Rates/Rate+Relief+Programs/disconnect2011.htm

The findings of the 2011 energy Disconnection report are:

- Low-income households tend to use less energy than non-low-income households.
- Even though one-third of all California households are enrolled in CARE, varying degrees of poverty mean affordability is still an issue.
- California's proportion of households in poverty ranks 3rd after NY and DC, when adjusted for housing costs.
- It would require **$592 per household** annually to close the Affordability Gap. Of that amount, eligible customers received an average of **$375 per household** annually in 2010 through a variety of assistance programs including CARE, Low Income Energy Efficiency, LIHEAP, Weatherization Assistance Program (WAP), American Recovery and Reinvestment Act (ARRA), and utility emergency grants. DRA estimates that it would require an additional **$217** annually to close the energy affordability gap for California low-income customers.

DRA Report Finds
$217
AFFORDABILITY GAP
for California's Most At-Risk Energy Customers

DRA's 2011 report recommended:

- Set disconnection benchmarks that commit the utilities to disconnecting no more than 5% of low-income customers annually for PG&E and no more than 6% for Edison.
- Explore graduated discounts and utility debt management programs.

Advanced Metering Infrastructure (Smart Meters)

Smart Meter Opt-Out Programs

In response to numerous customer complaints regarding meter accuracy and the potential health and privacy risks of smart meters, the CPUC directed PG&E to submit an opt-out plan for customers in March 2011.

DRA actively advocated for a cost-effective opt-out solution to maximize the promised system-wide advanced metering infrastructure benefits, for which billions of dollars in ratepayer funds have already been invested. DRA recommended the CPUC address issues common to all the investor-owned gas and electric utilities deploying smart meters on a statewide basis. The differences in gas, electric, and gas-only advanced metering infrastructure (AMI) systems should be considered separately.

Additionally, in July 2011 DRA filed a motion with the CPUC seeking:

- Additional information on Radio Frequency (RF) emissions and to establish a public forum to discuss findings in order to satisfy customer concerns, so that customers can begin to benefit from the multi-billion dollar investment already made in smart meters.
- Initial cost data on opt-out alternatives to smart meters (e.g., radio-off, analog meters, etc.) from the utilities.

The CPUC subsequently directed the utilities to provide additional information on the above issues. In November 2011, the CPUC ordered Edison and SDG&E also to file customer opt-out plans for smart meters by December 1, 2011.

Additionally, DRA has filed a motion to stay the SoCalGas AMI project in the early stages of deployment because of the looming costs associated with gas pipeline safety upgrades [see p. 64]. Benefits from smart meters intended to support time-based pricing strategies for electric service are not applicable to residential gas service customers.

A CPUC proposed decision on the PG&E opt-out proposal was issued in late November 2011. It would:

- Levy a $90 one-time cost and $15 monthly cost to any customer that desires to opt out of their smart meter.
- Establish an account to track costs incurred by utilities through customers opting out of smart meters.

In all likelihood, many of the costs incurred on behalf of participating opt-out customers will be borne by non-participants. DRA recommended additional customer protections be added to PG&E's proposal. In 2012, DRA will monitor the size of these costs and advocate that they do not become overly burdensome to non-participants.

Smart Grid

Customer Privacy Rules

The CPUC established a new phase of the ***Smart Grid*** proceeding with the goal of determining the need for privacy rules to protect customer energy usage data. The proceeding also considered customer access to energy usage and pricing data.

DRA contributed to, and supported the adoption of, privacy rules developed by the Center for Democracy and Technology and the Electronic Frontier Foundation. These rules are based on the Department of Homeland Security's Fair Information Practice Principles, which promote transparency, security, and accountability. DRA urged the CPUC to draft privacy rules that:

- Limit access to personally identifiable information without customer consent to specific activities, such as billing and provision of electric service.
- Require *all* third parties with access to customer usage data to follow the same privacy and security rules as the regulated utilities.

What is it?

The Smart Grid: The Smart Grid leverages the Advanced Metering Infrastructure (AMI). Also known as smart meter, AMI is a metering and information technology (IT) system that will provide benefits to customers and service providers by automating meter reading, optimizing utility resources, and reducing electricity demand by providing customers with more detailed information about their energy usage. However, privacy concerns arise with the smart meter's collection of granular energy usage data which can reveal intimate details of the household—such as whether or not a burglar alarm is set. Under Senate Bill 1476 (Padilla, 2010), investor-owned utilities using smart meters are required to allow customers to access their own energy usage data without requiring them to share personally identifiable information with non-utility entities. In 2009, the CPUC initiated a new phase in the Smart Grid proceeding to determine how best to provide customers access to pricing and usage data and to develop privacy rules to protect customer energy usage data.

- Establish a complaint process at the CPUC for the enforcement of the privacy and security rules.

DRA also supported requiring customer notification for useful pricing information such as *tier alerts*. A tier alert notifies customers via text or email when their energy usage moves from one price tier to the next. At this time, real-time/near real-time and wholesale pricing information is not useful, and potentially confusing, to customers because tiered rates are not related to real-time or wholesale pricing information.

DRA Advocated for
STRONG PRIVACY RULES

In July 2011, the Commission adopted privacy rules based on the Fair Information Practice Principles, as California policy for the Smart Grid. The privacy rules are the first such rules adopted in the nation and are being looked to by other state commissions and the federal government as a model to follow.

The CPUC-adopted privacy rules:

- Allow utilities and their contractors to use customer data without customer consent.
- Require customer consent for non-utility access to any customer data or utility use of

data that do not involve certain activities related to billing, the provision of energy service, or other CPUC-authorized activity.
- Adopt specific guidelines for data handling and customer notification.

The decision also instructed the utilities to provide customers with access to pricing and usage data. However, the CPUC declined to monitor the privacy policies of non-utility companies, but instead to require the utilities to inform customers of the potential uses and abuses of sharing customer energy usage data with non-utility entities. Customers may be unaware that energy usage data being collected by smart meters may disclose intimate personal details.

DRA will continue to advocate at the CPUC to further strengthen the privacy rules through subsequent phases of the proceeding. The utilities are currently implementing privacy rules according to CPUC's July 2011 decision. In October 2011, the utilities submitted to the CPUC proposed tariffs incorporating the new privacy rules. DRA protested due to inconsistent implementation of the rules across the three utilities. In November 2011, the utilities also submitted to the CPUC their proposed statewide rollout of home area network (HAN) devices, which will provide customers with real-time energy usage and pricing information. DRA opposed the request due to the lack of information provided in those plans.

By the end of January 2012, the utilities are expected to make certain pricing and usage data available to customers, update their tariffs to provide third parties access to customer data through the utility data system, and initiate a pilot study to provide customers with access to real-time or near-real-time pricing information. A second phase regarding Smart Grid privacy rules commenced in September 2011 to determine whether the privacy rules should apply to gas corporations, electric service providers, and community choice aggregators. A final decision on those issues is anticipated in June 2012.

NATURAL GAS

PG&E Gas Transmission and Storage Rate Case

PG&E submitted its request to increase its revenue requirement for its 2011 Gas Transmission and Storage Rate Case in 2009. PG&E's proposed increase is greater than the $461.8 million that was recovered through rates in 2010 pertaining to operations, policy, market structure, cost allocation, and rate design.

PG&E's Revenue Requirement Request

Year	Request
2011	$ 529.1 million
2012	$ 561.5 million
2013	$ 592.2 million
2014	$ 614.8 million

Subsequently DRA negotiated with PG&E to resolve the issues and reached a settlement agreement, which provides for:

- Funding for specific projects, up to a cost cap, only if the project is actually built and operational.
- A 2011 expense level for pipeline integrity management of $22 million with annual escalation through 2014.
- A one-way balancing account to be established for integrity management expenses during the term of the settlement, which provides an incentive for PG&E to properly fund this activity since any accumulated balance will be returned to customers.
- Requires PG&E to provide a semi-annual Gas Transmission and Storage Safety Report.

The agreed upon revenue requirements in the settlement are:

Year	Revenue Requirement
2011	$514.2 million
2012	$541.4 million
2013	$565.1 million
2014	$581.8 million

In April 2011, the Commission adopted the settlement agreement, which resulted in cumulative savings for PG&E customers of approximately $207.1 million over the four year period.

$207.1 million

Savings for PG&E Gas Customers

Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines

Following the San Bruno natural gas pipeline explosion in September 2010, the CPUC undertook several efforts to improve pipeline safety in California, including:

- Opened a Safety and Reliability Proceeding.
- Required Pipeline Safety Enhancement Plans.
- Developed a Citation Program.

In February 2011, the CPUC opened a proceeding for the purpose of adopting new safety and reliability regulations for natural gas transmission and distribution pipelines, as well as related ratemaking mechanisms. DRA supported the CPUC's efforts to improve gas pipeline regulations to protect California customers as well as the need to consider potentially reducing PG&E's rate of return or requiring cost sharing for shareholders.

Pipeline Safety Enhancement Plans (PSEP)

In August 2011, California's natural gas utilities submitted their Pipeline Safety Enhancement Plans (PSEP) as required by the CPUC's June 2011 decision on testing and replacing pipelines.

PG&E:

PG&E requested approximately $768 million in revenue requirements for 2011-2014. PG&E forecasted spending about $2.2 billion during that period for its PSEP, but requested to recover approximately $2 billion from ratepayers.

- Of the $2.2 billion, PG&E shareholders proposed to bear actual 2011 expenses, which are forecasted to be about $220.7 million in 2011 expenses and about $1.4 million for capital projects expected to be operational in 2011.
- PG&E shareholders also proposed to bear about $215.4 million in non-PSEP activities and about $98 million on work relating to post-1970s pipe (for Maximum Allowable Operating Pressure, Validation and Strength testing).
- PG&E proposed to recover PSEP costs through a separate Gas Pipeline Safety (GPS) surcharge to be included in the customer class charge to end-users.

These latter two amounts are not part of the $2.2 billion in PSEP costs for 2011-14. PG&E had no cost forecast for its PSEP scope of work beyond 2015.

SoCalGas / SDG&E:

SoCalGas/SDG&E forecasted a combined spending of about $1.7 billion in direct costs for its PSEP over the 2012-2015 period. The utilities would utilize a base case with estimated spending of approximately $1.4 billion of its PSEP over the 4-year period 2012-2015. The utilities proposed to recover:

- The fully loaded costs which correspond with that amount (i.e., plus loaders and escalation).
- A revenue requirement of $7.3 million for 2011 and $648.7 million for 2012-2015.
- $1.5 billion in costs for 2016-2021.
- Total revenue requirements of nearly $12 billion for 2011-2023 to implement the projects with the loaded and escalated costs.
- PSEP costs through a separate, discrete GPS surcharge to end-users.

Shareholders proposed to not bear any costs.

Petition to Stay SoCalGas Smart Meter Program

DRA and TURN have requested that the Commission reconsider its approval of SoCalGas' $1 billion Smart Meter program. Circumstances have changed significantly since the Commission narrowly approved SoCalGas's Smart Meter proposal in April 2010. SoCalGas customers are facing the possibility of significant rate increases to pay for pipeline safety measures. SoCalGas proposes that ratepayers pay $2.5 billion for the first phase of its pipeline safety program, with an associated revenue requirement increase over the life of the investment exceeding $9 billion. The second phase of the program could require additional billions of dollars of expenditures.

Southwest Gas:

Southwest Gas (SWG) forecasted spending approximately $7.4 million for its PSEP. SWG did not propose to adjust rates as part of its PSEP. Rather, rates will not be adjusted until the CPUC issues an order following SWG's next GRC. The annual revenue requirement associated with the SWG PSEP is approximately $1.5 million. SWG shareholders are not proposing to bear any of the costs of its PSEP.

DRA is currently reviewing the utilities' pipeline safety and reliability plans to determine whether the CPUC should approve any or all portions of the utility proposals. DRA will seek to balance the goals of enhancing gas pipeline public safety while obtaining the lowest possible rates consistent with reliable and safe service levels. DRA expects to file its testimony at the end of January 2012. A final CPUC decision is expected in mid-2012.

CPUC Citation Program

In December 2011, the CPUC adopted a Citation Program to delegate specified authority to the CPUC staff of the Consumer Protection and Safety Division (CPSD) to issue citations to all gas corporations to enforce gas pipeline safety compliance. The program delegates authority to CPSD Staff to issue citations and to levy fines on gas corporations to enforce compliance with state and federal gas safety regulations. In addition, the Citation Program does not create any "safe harbor" for a gas corporation to protect itself from an enforcement action or private tort claims.

The CPUC adopted many of DRA's recommendations including:

- Citations will be made public and local authorities informed.
- Requirements will be incorporated from the recently enacted California gas safety legislation.

Fines will be paid by gas corporation shareholders, and not by ratepayers, into the state's General Fund, as required by statute.

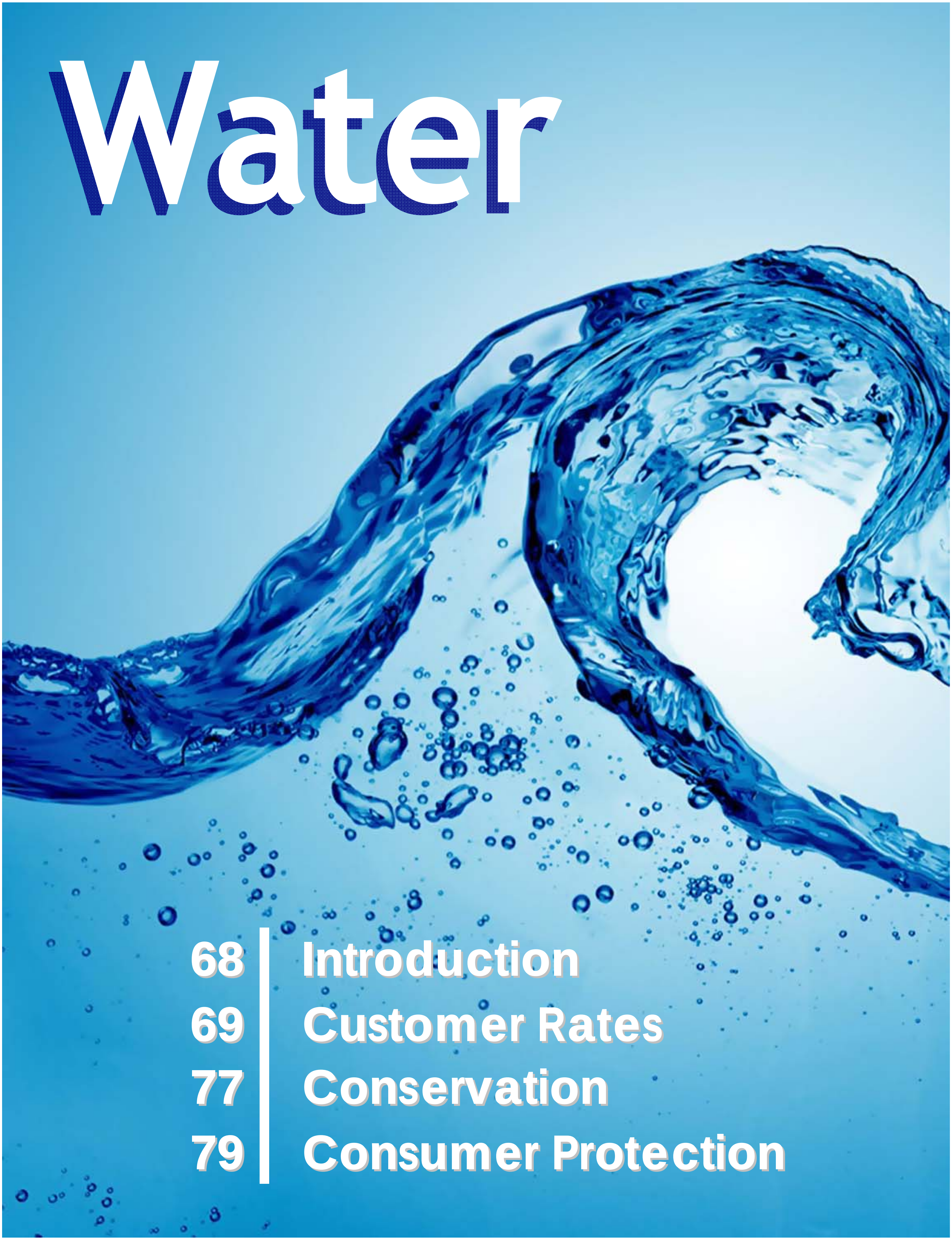
Energy Efficiency Public Purpose Program

SB 939 (Wright, 2011) in June 2011 authorized the transfer of up to $155 million of natural gas Public Purpose Program (PPP) surcharges to the state's General Fund, thereby reducing the funding available for natural gas Energy Efficiency programs to zero. The CPUC requested stakeholders to weigh-in on whether, and how, to mitigate the loss of budget to already-approved natural gas Energy Efficiency programs.

DRA recommended solutions that would balance replacing energy savings from the efficiency programs that had already been factored into procurement and GHG forecasts with not requiring customers to pay twice for the same programs. DRA recommended to:

- Authorize utilities to use unspent gas surcharge funds and evaluation, measurement, and verification (EM&V) funds from previous program cycles.
- Authorize utilities to use unspent electric funds after unspent gas funds are exhausted.
- Set aside unspent surplus funds for the Consolidated Financing Program (CFP) with the requirement that the funds be leveraged with private capital to provide low interest loans for customer Energy Efficiency projects (CFP would be managed by the California Advanced Energy and Alternative Transportation Financing Authority - CAEAFTA).
- Require an annual independent financial audit of Energy Efficiency fund collections and expenses to improve accountability and transparency.

Contrary to DRA's recommendation, the Commission voted to authorize the utilities to use unspent electric funds without limitation, which is not consistent with established CPUC policy. The Commission adopted a financial audit requirement on a one-time only basis, not on a recurring annual basis.



Water

DRA's goals are to effectively advocate for the lowest possible rates for water service consistent with reliable and safe service levels, and to actively contribute to advancing the state's many water policy goals including conversation, recycling, and climate change – including the water-energy nexus.

In 2012, DRA will continue to critically review water utility rate requests, operating expenses, and financial plans and to offer alternatives as necessary to ensure services are provided cost-effectively and also remain safe, reliable, and reasonable.

DRA will also be advocating before the Governor's office, Legislature, the CPUC and in other forums throughout the state to:

- Identify the best water supply solutions to address long-term needs.
- Explore ways to achieve energy efficiency savings through cost-effective water conservation programs.
- Advance Low-income programs.
- Examine the effects of water utility mergers and acquisitions.
- Evaluate the rate effects of new water quality regulations.

DRA will proactively work with decision-makers to ensure strong customer protections are in place to prohibit utility abuses and to ensure customers are provided with sufficient information to make well-informed decisions.

INTRODUCTION

DRA represents 1.3 million customers of investor owned **Class A & B water utilities**. The CPUC has regulatory jurisdiction over approximately 20% of all of California's urban water usage customers. DRA scrutinizes water utility requests for additional revenues that will increase customer bills. DRA advocates on behalf of water ratepayers in CPUC proceedings and participates in statewide planning processes at the Department of Water Resources and the California Air Resources Board. In 2011, DRA's efforts saved water customers over $23.3 million, resulting in an averaging monthly savings of $7.08 per customer.

DRA's efforts on Water issues are two-fold: 1) Review and analysis of water utility General Rate Cases (GRCs), which determine the amount of revenues a water utility may collect that in turn will impact a customer's bill; and 2) Development of water policy which sets rules and develops programs that shape the water industry.

In 2011, DRA had many successes including negotiating a settlement with Class A water companies that would lower the return on equity from 10.2% to 9.99%. DRA worked on 5 rate cases in 2011 that saved a total of $23.3 million from utilities' total revenue increase request of $70.2 million. DRA's advocacy on the removal of the San Clemente Dam project resulted in a proposed decision with numerous consumer protections, including capping project costs. Additionally, Water Conservation efforts resulted in progress with focus on Water Recycling and other conservation programs.

WHAT IS IT?

Class A Water Companies: Utilities that have over 10,000 service connections.

Class B Water Companies: Utilities that have more than 5,000, but less than 10,000 service connections.

CUSTOMER RATES

Cost of Capital

In May 2011, three of the four largest Class A water companies (California American Water, San Jose Water, and Golden State) filed an application on ***Cost of Capital*** requesting the CPUC authorize a return-on-equity of 11.50%, above their previously authorized equity rate of 10.2%. California Water Service requested a slightly lower 11.25%. Both Golden State and California American proposed the CPUC authorize capital structures for ratemaking purposes that artificially inflate the equity component, and therefore the ultimate revenue and return for the companies. Both utilities supported this request as necessary given balances in memorandum accounts that are earning less than the rate of return. If adopted in their entirety, the utility requests combined would increase 2012 water rates by approximately $30 million.

DRA asserted that the CPUC should not adopt the utilities' proposed artificial capital structures, but should instead rely upon market data, capital pricing models, and more reasonable assumptions of growth for an authorized equity return of 8.75% (and 9% for California American based upon its parent company bond rating).

In October 2011, DRA negotiated a settlement with the four utilities for a return on equity of 9.99%. This lower rate demonstrates a clear recognition of the lower costs for financing capital projects while simultaneously avoiding the considerable expense of additional consultant and attorney fees to litigate the issues before the CPUC. The settlement will lower rates for Golden State Water Company, San Jose Water Company, California Water Service, while it will result in a slight increase in rates for California American Water. The impact on each utility's revenue requirement starting in 2012 is as follows:

- Golden State Water Company: Annual decrease of $2.95 million.
- San Jose Water Company: Annual decrease of $2.38 million.
- California Water Service: Annual decrease of $4.53 million.
- California American Water: Annual increase of $2.33 million.

DRA expects the Commission to issue a final decision adopting the settlement in the first quarter of 2012.

WHAT IS IT?

Cost of Capital: The Cost of Capital is the overall percentage cost of the funds used to finance a utility's assets. Cost of Capital is a composite of the cost of the individual sources of funds including common equity stock, debt, and preferred stock. The overall Cost of Capital depends on the cost of each source and the proportion that source represents of all capital used by the utility. The authorized weighted Cost of Capital or rate of return is the percentage cost applied to the utilities' rate base to determine the revenues it should earn on rate base (investment).

California American Water

Statewide General Rate Case

In July 2010, California American Water (CalAm) filed its statewide rate case for 2012. CalAm is a multi-district water utility, which is required by the CPUC's 2007 revised rate case plan to submit all of its service districts at one time in a combined application when it files for a general rate case. Prior to 2007, CalAm could file rate cases for its various districts on a staggered basis. This is the first statewide general rate case in which CalAm has requested rate increases under the revised rate case plan. On a total district basis, CalAm requested to increase rates by $33.1 million or 19.68% above its present authorized base revenues of approximately $168.5 million. The table below provides a breakdown of the increase requested for each district for 2012.

CalAm 2012 Proposed Revenue Increase

District	Revenue Increase	Percent Increase
Larkfield	$974,100	37.00
Los Angeles	$5,367,000	21.90
Monterey	$11,948,700	27.60
Monterey Waste Water	$511,700	16.20
Toro	$407,900	97.50
Sacramento	$10,078,500	22.80
San Diego	$1,996,400	10.30
Ventura	$1,821,500	5.90
Total	$33,105,800	

CalAm also requested:

- The majority of deferred expenses, which had historically been allowed by the CPUC to accumulate interest at the short-term debt rate, now be allowed a full rate of return to compensate utility investors.
- Tax deductions resulting in lower customer rates not be considered by the CPUC if the actual deduction was unavailable because of a tax loss.
- Taxes be collected in rates, for ratemaking purposes, regardless of whether those taxes would actually be paid.

DRA instead recommended that rates increase by $16.5 million or 9.5% above CalAm's present authorized base revenues of approximately $172.9 million. The table below provides a breakdown of DRA's recommendation by each district for 2012:

DRA 2012 Proposed Revenue Increase

District	Revenue Increase	Percent Increase
Larkfield	$672,201	24.49
Los Angeles	$3,747,008	14.92
Monterey	$4,698,599	10.60
Monterey Waste Water	$207,777	6.70
Toro	$711	0.17
Sacramento	$6,001,697	13.56
San Diego	$971,311	4.76
Ventura	$212,177	0.64
Total	$16,511,481	

DRA recommended that:

- CalAm should use a consistent approach to taxes per long-standing CPUC policy.
- The benefits of allowable tax deductions should be calculated for ratemaking purposes consistent with the calculation of taxes that will be collected in rates.
- Equity returns be allowed only on those investments that are reasonable, prudent, and that provide service to customers, per long-standing CPUC practice.
- Cost-Benefit analysis be performed prior to adjusting frequency of meter reading.
- Distribution System Infrastructure Surcharge should be discontinued as a means of advance customer funding of capital projects.
- Greater incentive for CalAm should be provided to better control costs by limiting the number of balancing and memorandum accounts. CalAm is allowed to record expenses, ranging from water quality and customer service to ratemaking and regulatory policy.

In July of 2011, DRA negotiated and submitted to the CPUC a settlement with CalAm which achieved a $10 million reduction in the utility-requested revenue increase for 2012. CPUC approval of the terms of the settlement is expected in 2012.

DRA also litigated remaining issues totaling approximately $8 million in revenue requirement related to CalAm's federal tax deductions and forecasted capital spending. The outcome of this litigation will be determined by CPUC decision in early 2012. Also in 2012, the CPUC will examine in a second phase of rate design and cost allocation issues amongst customer segments.

San Clemente Dam Removal Project

In June 2011, DRA participated in CPUC evidentiary hearings on CalAm's request to recover up to $138 million for removal of the San Clemente Dam and reroute of the Carmel River. DRA supports this project, however asserted that CalAm's Monterey Peninsula customers should not be required to pay for its costs because CalAm:

- Imprudently managed the Dam over a period of 40 years.
- Did not properly assess and manage the sediment of the facility.
- Never assessed or collected funds for the costs of removing the Dam.
- Failed to propose and pursue a workable dam removal solution while costs could have been contained, but instead costs increased.

DRA, instead, recommended that current and future ratepayers should be completely exempt from any financial impacts of the proposed removal and reroute project.

The CPUC issued a proposed decision in November 2011, which was favorable to ratepayers and supported many of DRA's recommendations:

- Project costs would be capped at $49 million for ratepayers and amortized over 20 years.
- $21.7 million in "pre-construction" costs would be paid by CalAm shareholders.
- Ratepayers would not be responsible for other costs requested by CalAm.
- Standardized reporting protocol for conservation activities would be required.

A final decision is expected to be adopted by the CPUC in the first quarter of 2012.

Monterey Regional Desalination Project

In December 2010, the CPUC approved the settlement of CalAm, Monterey County Water Resources Agency, and Marina Coast Water District for the establishment of the ***Monterey Regional Desalination Project***, which is estimated to cost $500 million to construct and $15 million to run annually. The desalination project consists of intake wells located along the coast north of the city of Marina, a desalination plant located inland from the intake wells, a pipeline to convey desalinated water to the Monterey Peninsula, and other improvements to CalAm's Monterey service territory. The Desalination Project was proposed as a solution to serve Monterey County customers' needs in a water-constrained region.

WHAT IS IT?

In 2010, California American Water Company (CalAm), the California Coastal Conservancy, the Department of Water Resources, the National Oceanic and Atmospheric Administration, and other stakeholders reached an agreement to remove the San Clemente Dam, located in the Monterey service district, and reroute the Carmel River in order to eliminate seismic safety concerns and improve conditions for endangered steelhead trout. The agreement estimates the project cost at $83 million and commits state and federal agencies to raise $35 million toward the cost. CalAm ratepayers will cover the remaining $49 million in project costs.

In October 2010, CalAm filed an application with the CPUC seeking to recover up to $138 million associated with the project, including:

- $49 million for project costs.
- $21.8 million in "pre-construction" costs for tasks such as environmental analysis and interim seismic safety measures.
- $60 million for taxes, interest, and profit.

DRA opposed the settlement agreement based on analysis showing that the approved contract was too costly, too risky, and inequitable in both cost allocation and governance. DRA estimates that water bills for Monterey County residents and businesses could triple. DRA instead proposed a lower cost cap, a more equitable contribution from the Marina Coast Water District, the addition of the Monterey Peninsula Water Management District with area Mayors part of the formal governance structure, and an Operations & Maintenance proceeding to manage cost and risk.

However, in April 2011, implementation of the Regional Desalination project became uncertain due to conflict of interest investigations regarding a former public official's receipt of payments from a consulting firm that was selected to manage the project. The District Attorney's office in Monterey County has filed charges against one individual and the Fair Political Practices Commission is investigating the actions of several others. In addition, there is a lawsuit in superior court that could affect the legality of the project. These actions have raised questions about the viability of the desalination project and local officials have begun looking at alternatives should the Regional Desalination Project cease to be feasible.

The next steps in 2012 will depend upon the resolution of court proceedings and the Fair Political Practices Commission's findings. DRA will continue to advocate for a water supply solution that is both feasible and cost-effective, as well as to work with community stakeholders to evaluate viable project alternatives.

Suburban Water Rate Case

In January 2011, Suburban Water requested CPUC authorization to increase its rates and an overall revenue requirement of $72.5 million for water service. In June 2011, DRA submitted testimony recommending an overall revenue requirement of $64.2 million for an overall increase of 18.67% over present rates for Suburban's ratepayers.

Suburban claimed that a large part of its proposed increase in rates is due to increased costs associated with its water supply (purchased water, purchased power, pump taxes), which accounted for 45.5% of the overall revenue requirement of $19.2 million.

DRA recommended a lower revenue requirement asserting that Suburban's common administrative and general expenses should be allocated to its non-regulated affiliates in order to prevent cross-subsidizing non-regulated operations. DRA advocated for a revenue requirement that is $10 million less than the Suburban's original request.

DRA negotiated a partial settlement with Suburban in August 2011 on operating expenses, sales forecast, and plant projects. If the Commission adopts the settlement, excluding the litigated items, it will result in lowering Suburban's request by $7.4 million annually. Suburban would receive an increase in revenue requirement of approximately $13 million or about 24% for 2012. This increase will provide Suburban an overall revenue requirement of $67.0 million.

The key litigated issues include:

- Cost allocations from the parent to regulated operations.
- Deduction of Franchise Income Taxes.
- Production Tax Credit.
- Regulatory Expenses.

The above contested issues were litigated in an evidentiary hearing at the CPUC in July 2011.

In November a CPUC proposed decision was issued that would adopt the settlement as well as DRA's recommendations on cost allocations, Franchise Income Taxes, and the Production Tax Credit. A final CPUC decision is expected in January 2012.

Suburban Proposed and DRA Recommended Increase

	Proposed Rate Increase	Percent Increase over Present Rates	Test Year Revenue Requirement
Suburban (Requested)	$19,234,576	35.85%	$72,500,564
DRA (Recommended)	$10,104,785	18.67%	$64,227,900
Proposed Decision	$13,203,000	24.74%	$66,571,100

San Gabriel Valley Water Company

Los Angeles Division Rate Case

In 2010, San Gabriel Valley Water Company (SGVWC) requested to increase rates charged for water service in its Los Angeles division.

San Gabriel requested that its Los Angeles Division revenue requirement be increased by more than $10 million or 17.8% for its fiscal test year in 2011, providing San Gabriel with an overall revenue requirement of nearly $68 million. DRA recommended an overall revenue requirement of $61 million for an overall increase of 3.67% over present rates for San Gabriel's ratepayers.

In January 2011, San Gabriel and DRA submitted a partial settlement on the majority of the issues which resulted in an agreement for an overall increase of 11.7% for 2011 with a revenue requirement of $63.9 million.
The remaining contested issue was litigated in an evidentiary hearing to determine whether legal expenses associated with a Water Quality Memorandum Account should be included in rates as an ongoing expense. The memorandum account allows San Gabriel to track legal expenses associated with lawsuits pursuing water polluters for later recovery in rates. DRA opposed including these costs in base rates since the utility was still litigating the settlement on a contamination case, and it would be inconsistent with the CPUC's new rules for accounting for contamination proceeds.

$3.5 million
Saved for SGVWC Customers

The Commission issued its final decision in November 2011 approving the settlement agreement and adopting DRA's recommendation that San Gabriel be required to continue tracking costs in its Water Quality memorandum account.

San Gabriel Water Company: Los Angeles Division
Fiscal Year 2011

	Present Rates	Proposed Rates	Change	Percent Increase/ (Decrease)
San Gabriel (Requested)	$ 57,635,000	$ 67,867,700	$10,232,700	17.8%
DRA (Recommended)	$ 58,907,000	$ 61,069,500	$ 2,162,500	3.7%
D.11-11-018 (Adopted Settlement)	$ 57,264,500	$ 63,973,500	$ 6,709,000	11.7%

Fontana District Rate Case

In July 2011, San Gabriel Valley Water Company's (SGVWC) Fontana Division requested CPUC approval of an $8.2 million revenue requirement increase for 2012-2013 – or a 14.2% increase over its current revenue requirement. The request, if approved, would result in an overall revenue requirement of $65.8 million.

DRA issued its report in November 2011 addressing Fontana's requests regarding its expenses, conservation programs, plant additions, and amortization of memo and balancing accounts.
DRA's analysis determined that SGVWC should make the following changes to its proposal:

- Reduce conservation expense requests because Fontana is already close to meeting its 20% by 2020 water conservation goals, as required by the Water Conservation Act of 2009 (SB X7-7).
- Reduce 3 of 4 requested new employee positions because their need was not justified.

- Reduce approximately half of its requested capital budget given that these projects were not justified or could be deferred, for a savings of nearly $41 million.
- Disallow a portion of the Sandhill Treatment Plant due to overbuilt capacity, which would result in a reduction of $15.7 million and require SGWC to refund ratepayers $11.5 million in rates.
- Maintain the CPUC's prior disallowance of $3.1 million on Fontana's office complex.
- Maintain the CPUC's prior disallowances of various costs totaling nearly $4 million.

Based on these findings, DRA recommended the Fontana Division should receive a $1.2 million revenue requirement increase - or 2.1% increase above its current revenue requirement for 2012-2013. This would result in an overall revenue requirement of $58.9 million compared to SGVWC's request of nearly $66 million. An alternative dispute resolution process was completed in December 2012. Evidentiary hearings are scheduled to begin in January 2012.

DRA Advocates for
$7 MILLION DECREASE

A final CPUC decision is scheduled for mid-2012.

Golden State Water Company

Statewide General Rate Case: Regions I, II, III, and General Office

In July 2011, Golden State Water Company (GSWC) filed an application requesting authorization to increase rates charged for water service for 2013-2015, covering its Regions I, II, and III.

GSWC Proposal

Year	Proposed Revenue Increase	Percent Increase
Test Year 2013	$ 58,053,200	21.4%
Attrition 2014	$ 8,926,200	2.7%
Attrition 2015	$ 10,819,600	3.2%

GSWC serves over 250,000 service connections and its service territory covers both Northern and Southern California serving cities such as:

- **Region I:** Arden Cordova, Clearlake, Ojai, and Bay Point.
- **Region II:** Artesia, Cloverdale, and Norwalk.
- **Region III:** Claremont, San Dimas, Barstow, San Gabriel, and Wrightwood.

In the latter half of 2011, DRA conducted discovery on plant additions, sales forecast, operating expenses, and affiliate issues. DRA expects to issue its findings in written testimony in February 2012. A final CPUC decision is expected by June 2012.

La Serena

In 2011, the CPUC addressed a long-time litigation action regarding ratemaking treatment of Golden State Water Company's (GSWC) ***La Serena project***, which had been ongoing since 2007. DRA had advocated that the entire $3.5 million cost of the project should be excluded from rate base and that GSWC should be responsible for recovering the costs from the developers who would benefit from the project. In 2010, the CPUC issued a final decision which ordered GSWC to refund $1.1 million to ratepayers and reduce the company's rate base by $2.5 million. Although the financial outcome was somewhat favorable to ratepayers, the CPUC decision was inconsistent with its long standing practice of applying ***Tariff Rule 15***. Instead, the CPUC

WHAT IS IT?

La Serena Project: Located in the Santa Maria service area in Southern California, the project consists of a 0.5 million gallon water reservoir, booster stations, pressure filters, and ancillary pipelines at the plant site.

Tariff Rule 15: Projects undertaken to provide water service to new developments must be paid for by the developers through facilities fees, advances, or contributions - and not by existing ratepayers.

allocated the cost between both GSWC and ratepayers.

This shift in policy was not supported by the record and would set a bad precedent that could result in customers cross-subsidizing water infrastructure facilities for future new developments that should, instead, be paid for by developers under Tariff Rule 15 facilities fees. Consequently, in November 2010, DRA filed for rehearing of the issue on the grounds that Tariff Rule 15 does not allow the sharing of capital costs between new developers and existing ratepayers when the new facilities in question provide 50% or more to the need of the new development.

In July 2011, the CPUC granted DRA's request for rehearing on the La Serena project. This decision affirmed DRA's argument that historically the CPUC has interpreted Tariff Rule 15 to require the costs of new development to be allocated to the developers. GSWC subsequently challenged the CPUC's July 2011 decision. In October 2011, the CPUC denied GSWC's challenge. The current rehearing is currently underway and is being addressed in the GSWC 2011 GRC. DRA expects a final decision will be issued in the 4th quarter of 2012.

Apple Valley Ranchos Water Company

General Office Rate Case

Apple Valley Ranchos Water Company (AVR) filed its 2012 General Rate Case (GRC) application with the CPUC in January 2011 requesting a $3.9 million revenue requirement or a 20.0% increase over current customer rates. AVR serves approximately 19,500 customer service connections in, and near, the town of Apple Valley in San Bernardino County.

DRA issued its report in May 2011 recommending AVR increase customer rates by only 5.7%, which would be $2.8 million less than requested by the utility. DRA asserted that AVR's request should be denied based on:

- Failure to justify four new positions.
- The authorized 2% merit raises authorized in the last GRC were not dispensed to its employees, and DRA recommended disallowing the merit increase.
- Requested bonus is a 400% increase over the bonuses paid in 2010.
- Group Pension plan estimates are based on questionable actuarial reports and should be rejected because they are based on questionable actuarial reports.
- Failure to adequately support the need for the project or cost estimates for the office expansion.
- Requested stock transfer expense impacts the memorandum account and is not valid.

DRA negotiated a partial settlement on most of the operating expenses and plant additions which reduced AVR's requested 2012 revenue increase by $1.6 million and participated in hearings to support an additional reduction of $670,000. DRA litigated the remaining issues, including payroll, merit increase, employee bonus, employee benefits, and office expansion. A proposed decision on the AVR GRC is expected in the first quarter of 2012.

$1.6 million

Negotiated savings, plus a potential for $670,000 more, to be decided by the Commission

Catalina Island Water General Rate Case

In November 2011 Catalina Island Water Operations (a subsidiary of Southern California Edison), a Class C water utility with less than 2,500 service connections, formally requested that the CPUC increase its revenue requirement by $3.27 million for 2011 - or 83% over present authorized base rates for a total revenue requirement of $7.2 million.

DRA reviewed all operating expenses and plant estimates to determine the reasonableness of the proposed revenue requirement for 2011 and determined that Edison's request to:

- Recover fire damage should be offset by any insurance proceeds received by the utility given that ratepayers subsidize the insurance premiums through rates.
- Implement an alternate rate proposal whereby its electric customers would

- subsidize the rates of Santa Catalina water customers should be rejected because this would result in cross-subsidization since Santa Catalina water ratepayers are a distinct and separate class of customers which are not served by the electric utility operations.

Based on its analysis, DRA recommended to:

- Disallow $690,000 in operating expenses.
- Disallow $2.8 million in plant costs.

DRA's adjustments reduced Edison's revenue requirement increase by $902,000 resulting in an increase to Santa Catalina's revenue requirement of $2.4 million for 2011 - or 60% increase for a recommended total revenue requirement of $6.3 million.

A proposed decision is expected in the first quarter of 2012.

San Jose Water Company

Montevina Water Treatment Plant Upgrade

In September 2010, San Jose Water Company (SJWC) requested $75 million to upgrade the existing direct filtration system to membrane filters at its Montevina water treatment plant. SJWC premised its request on the need and ability to capture and treat additional water during storm events. SJWC also requested to recover its costs in rates prior to the completion of the project.

In February 2011, DRA opposed San Jose's request because:

- The capital project is not used and useful while it's being constructed and should not be included in the utility rate base until fully completed, functional, and providing utility service.
- The utility's estimate of the additional amount of water that the upgraded plant can produce is overstated.
- The substantial cost of the project can be reduced with alternative, less costly measures.

DRA has recommended more cost-effective alternatives for upgrading the Montevina Water Treatment Plant that will save ratepayers millions of dollars. A CPUC proposed decision is expected in early 2012.

Conservation

Recycled Water

In November 2010, the CPUC opened a proceeding to develop a comprehensive policy framework for ***Recycled Water*** for the larger water utilities in the CPUC's jurisdiction. The proceeding addressed issues of cost-benefit analysis, financing, rate design, goal setting, legal issues, and public outreach, along with inter-agency coordination. CPUC workshops held in 2011 focused on institutional coordination and challenges, financing, and cost-benefit evaluations.

DRA recommended the CPUC:

- Adopt policies designed to increase the amount of Recycled Water delivered by water utilities in a cost-effective manner, consistent with integrated regional water management planning efforts.
- Set enforceable Recycled Water development goals based on region-specific criteria.
- Require costly and complex water recycling projects to be more comprehensive with a higher level of CPUC scrutiny.

DRA will develop other recommendations on issues such as rate design and public outreach as the proceeding moves forward.

The CPUC will hold workshops on Recycling issues through April 2012, to examine rate design and goal-setting. The CPUC expects to issue a decision with rules to guide utility proposals and CPUC evaluation of future Recycled Water projects by the end of 2012.

What is it?

Recycled Water: Treated wastewater that can be put to beneficial use. The main uses that will be considered in the CPUC rulemaking are non-potable reuse (i.e., for irrigation and industrial use) and indirect potable reuse (e.g., advance treated water which is injected into a groundwater basin and can then be extracted for potable use).

Conservation Programs

In May 2011, the CPUC's proceeding on ***Water Conservation programs*** and policies culminated with its final decision on data reporting requirements for both conservation programs and low income programs.

DRA supported cost-effective conservation programs and pricing for all customer classes, flexibility for adapting to new opportunities and customer preferences, accountability, and effectiveness in achieving water savings. DRA also proposed the CPUC develop a standardized reporting protocol for conservation activities.

The CPUC's May 2011 decision adopted:

- A conservation goal for all Class A water utilities of 1-2% annual reduction in consumption per service connection.
- Demand reduction goals per customer are required through ***conservation rate design*** and other programs and then evaluated in general rate cases.
- Standard Report Protocols.

In 2011, DRA began analyzing the impacts of rate design pilot programs on water use and customer bills. DRA's findings will be used to recommend modifications in general rate cases if these programs are found to be harmful to ratepayers. DRA will coordinate its efforts across various water proceedings to ensure that conservation activities reflect and comply with state regulations and goals, such as the 2009 Water Conservation Act (SB X7-7, Steinberg).

In 2012, DRA will focus on conducting thorough analyses on the impacts of the water utilities' ***WRAM/MCBAs*** to determine whether adjustments are necessary and that risks are equitably balanced between ratepayers and utilities. In addition, DRA will monitor and analyze utilities' Urban Water Management Plans to ensure compliance with SB X7-7.

What is it?

Water Conservation Programs: Activities funded through rates such as rebates for water-saving devices (high efficiency toilets and showerheads), audits, and education and public outreach.

Conservation Rate Design: Approaches to provide a conservation signal through bills, such as collecting a greater proportion of revenues through volumetric charges (instead of the meter charge) or tiered rates. CPUC proceeding I.07-02-011 resulted in the implementation of conservation pricing (tiered rate design), increased conservation budgets, and revenue adjustment mechanisms for most Class A utilities.

Water Revenue Adjustment Mechanisms (WRAM): A symmetrical mechanism which compensates utilities for the reduction in revenues that conservation rate design and programs may cause due to loss of sales. The mechanism may also result in refunds to ratepayers if water sales exceed those authorized by the CPUC.

Modified Cost Balancing Account (MCBA): A symmetrical mechanism which tracks the difference between the actual and forecasted water supply costs of a utility. Any over collection or under collection associated with loss/increase in sales or increases/decreases in supply costs are offset with the WRAM.

CONSUMER PROTECTION

Affiliate Transactions

In 2009 the CPUC opened a proceeding to develop standard rules and procedures for regulated water and sewer utilities governing ***affiliate transactions***, which resulted in a final decision in October 2010 favorable to ratepayers.

In March 2011, however, several Class-A water utilities filed a petition to modify the October 2010 decision requesting that the CPUC rules be modified to:

- Exclude "parent" companies of regulated utilities from the definition of "***affiliate***."
- Exclude non-water related and out-of-state affiliates.
- Shift the cost burden associated with future compliance audits toward ratepayers.

DRA argued that standard rules and procedures for regulated water and sewer utilities are necessary to effectively govern affiliate transactions and the use of regulated assets for non-tariffed utility services. The rules originally adopted in 2010 are necessary to uphold ratepayer protections by requiring uniformity, prevent cross-subsidization, provide access to relevant utility books and records, prevent financial ring-fencing measure, and establish compliance audits and reporting.

WHAT IS IT?

Affiliate: Any entity whose outstanding voting securities are more than 10 percent owned, controlled (directly or indirectly) by a utility, its parent company, or by any subsidiary of either that exerts substantial operational control.

Affiliate Transaction Rules: Governing transactions by a water utility or sewer company with a parent company and/or affiliate with regard to the use of regulated assets and personnel for non-tariffed utility products and services. In October 2010, the CPUC adopted Affiliate Transaction Rules in D.10-10-019 to provide clear and uniform directions and guidance. Key rules include:

- Uniform and consistent rules.
- Utility protection from holding company abuse, bankruptcy, or other financial hardship.
- Prevention of cross-subsidy.
- Requirements for monitoring and audits.
- Prevention of anti-competitive behavior.

The CPUC issued a final decision in October 2011 which made minor modifications to the Commission's previously adopted rules and upheld its 2010 Affiliate Transactions rules which will protect ratepayers.

Communications

DRA's goal is to effectively advocate for the fair treatment of telephone customers in California to ensure *services* remain affordable, high quality and reliable, and *customers* remain well-informed and are protected from fraud or abuse.

In 2012 DRA will continue to actively work to advance the state's goals on universal service, broadband deployment and adoption, and the timely provision of emergency services.

DRA will also intervene on customer complaints and identify industry problem areas by reviewing market trends and utility service offerings. DRA will also work with decision-makers to ensure strong customer protections are in place that require swift resolution for billing and service problems, prevent abusive marketing practices, and ensure customers are provided with sufficient information to make well-informed decisions.

Through our pleadings, lobbying efforts, and other daily communications before the Governor's office, Legislature, CPUC, and in other forums throughout the state, DRA strives to ensure communications services are provided cost-effectively while connecting all members of society with a high level of reliability and access to innovative technologies.

INTRODUCTION

California's telecommunications network is central to the daily life, work, safety and education of people throughout the state. DRA represents all customers of telephone carriers, seeking to improve service quality and reliability, hasten response times by operators and repair personnel, maintain rates at reasonable levels, increase coverage and reliability for 911 and emergency services, and protect consumers from fraud, unauthorized charges, and abusive marketing practices. DRA also actively participates in the promotion and development of federal and state programs to expand broadband access across California at reasonable costs.

In 2011, DRA sought to protect customer dollars by targeting inefficiency and improving the success of ratepayer-funded programs. DRA promoted improved guidelines and stricter accountability and outreach requirements for the California Advanced Services Fund (CASF) program, to promote and speed the adoption of broadband in unserved and under-served regions of California. DRA also urged the Commission to open an investigation and to oppose AT&T's federal merger application, because the resulting concentration in the wireless market would have increased costs substantially for all Californians. DRA continues to fight for improvements in the LifeLine program, seeking to offer state subsidization of wireless and VoIP services as an option for low-income customers, and to streamline the application process for eligible beneficiaries.

Consumer Protection

AT&T/ T-Mobile Merger

In June of 2011, AT&T notified the CPUC of its intention to merge its wireless business with that of T-Mobile, which would result in a national merger between two of the four largest national wireless companies. The proposed merger, if approved, would have reduced consumer choice, raised prices, and stifled innovation in the wireless market. The combined company would have controlled 47% of the wireless market and 55% of the broadband market in California.

Final approval of the merger lies with the Federal Communications Commission (FCC), which regulates communications and the federal Department of Justice (DOJ), which reviews proposed mergers for potential anti-trust violations. However, California PU Code section 854 requires the CPUC to determine that a proposed merger will provide short-term and long-term economic benefits to customers and not adversely affect competition. As states are federally preempted from setting rates for wireless services, California's best window of opportunity to protect customers occurs in advance of any merger, during the CPUC review phase.

DRA urged the CPUC to open and conduct a full investigation before deciding whether to grant approval of the merger. The CPUC approved DRA's request and opened the investigation in June 2011. DRA advocated that the CPUC reject AT&T's request for merger because of the harms decreasing competition would have on customers. To mitigate the harms to consumers, if a merger were to be approved, DRA proposed protective measures the CPUC should require for T-Mobile customers, such as a sufficient period of rate freeze and prevention of early termination fees for opt-out of involuntary transfer to AT&T service.

DRA OPPOSED
AT&T Merger, which would have reduced competition, raised rates, and harmed innovation and choices for customers.

In August 2011, the DOJ filed a lawsuit opposing the merger, a suit subsequently joined by the California Attorney General and the attorneys general of six other states. This resulted in the CPUC putting its investigation of the merger on hold, pending the outcome of the DOJ's lawsuit. In November 2011, AT&T filed a request to withdraw its merger application with the FCC, a request the FCC approved. In December 2011, AT&T announced that it would not pursue a merger with T-Mobile. Subsequently, the DOJ and AT&T filed a joint motion to "stay" the proceeding in District Court. The DoJ's pending lawsuit is scheduled to be heard in February 2012.

LifeLine

In November 2010, the CPUC signaled its intention to update the ***California LifeLine program*** so that it evolves along with advancements in communications technology and complies with **AB 2213 (Fuentes, 2010)**. In March 2011, the CPUC opened a new LifeLine proceeding to clarify program objectives, process, and to incorporate options for new technologies available to low-income consumers. A key issue to be addressed in updating the LifeLine program is to redefine ***Basic Service*** so that it includes advanced technologies. The current definition would necessarily exclude wireless and VoIP service providers from participating.

DRA supports the objectives of both the current wireline LifeLine program as well as efforts to expand access to wireless and VoIP, so that low-income customers may choose technologies that best serve their needs. Wireless service also presents public safety issues that differ from wireline service. DRA recommended that the CPUC take action to prevent "double dipping" and subsidize only one service per household. Such rules are essential to preserve the fiscal integrity of the LifeLine program by not over-extending the fund, which is subsidized by other ratepayers.

A proposed decision revising the definition of Basic Service was issued in November 2011, which sets out the features and functions necessary for wireless service to be a Basic Service analogous to wireline service. The proposal supported many of DRA's recommendations including a higher allocation of wireless minutes and time in order to be equivalent, if not identical, to the Basic Service offered via wireline technology. DRA expects that a final decision will be issued in the first quarter of 2012.

What is it?

The California LifeLine Program: Founded by AB 1348 (Moore, 1983), also known as the Moore Universal Telephone Service Act (PU Code section 871). The program is administered by the CPUC and subsidized by all telephone ratepayers, providing discounted telephone service for low-income customers.

Customers qualify for the program in one of two ways:

- Proof of income (e.g., tax records or pay stubs) demonstrating that they earn no more than 150% of the federal poverty level.
- Proof of enrollment in other low-income programs, such as WIC (Women w/Infants and Children) or food stamps.

The program provides a specific support amount of $12.25 per month, which is adjusted annually. CPUC decision D.10-11-033 required the CPUC to define guidelines for wireless and VOIP carriers so that they could voluntarily offer the LifeLine program to their customers. The ability to offer advanced technologies depends upon the CPUC updating its definition of ***Basic Service,*** which is currently wireline-specific.

AB 2213 (Fuentes, 2010): Changed the definition of what services must be provided to LifeLine subscribers from "a single party line" to "one LifeLine subscription" at a principle place of residence in order to accommodate technologies other than traditional wireline service.

Basic Service: Established by the CPUC in 1996 in D.96-10-066, it is specific to wireline service. Basic service is telephonic service that provides all of the features and functions deemed necessary by the CPUC as conveniences and necessities for modern life, such as the ability to make and receive calls, access to the toll carrier of your choice, access to 911, etc.

Non-Dominant Inter-Exchange Carriers

In February 2011, DRA requested that the CPUC modify its previous 2010 decision regarding the CPUC registration process for ***Non-Dominant Interexchange Carriers (NDIEC)***. DRA asserted that the CPUC should require NDIEC companies to post performance bonds sufficient to cover the payment of taxes, fees, advances and deposits, penalties, and restitution, in

What is it?

Non-Dominant Interexchange Carriers (NDIECs): Companies that provide stand-alone telecommunications services including long-distance, high-speed data service, operator services, and prepaid debit card services.

compliance with statute. In September 2011, the CPUC granted DRA's request that NDIEC companies should post performance bonds that would cover these costs.

During 2011, various NDIECs requested that the CPUC mitigate its rules designed to protect customers:

- **Worldwide Marketing Solutions, Inc.:** In April 2011, Worldwide Marketing Solutions, Inc (WWMS) petitioned the CPUC for exemption from the performance bond requirement on the grounds that it did not produce substantial intrastate revenue. DRA asserted that WWMS's request should be denied because the CPUC intended a carrier to post a bond regardless of the amount of the carrier's intrastate revenue, due to the inherent difficulty in collecting fines or restitutions from companies that engage in fraudulent or inappropriate practices and cease operations or file for bankruptcy. A CPUC decision is expected in 2012.

- **NovaTel LTD, Inc. (NovaTel):** In August 2011, NovaTel LTD, Inc. (NovaTel) requested that the CPUC modify its rules to permit an *irrevocable letter of credit* to serve as an alternative to posting a performance bond because NovaTel had been "experiencing difficulties" obtaining a performance bond. DRA responded to NovaTel's petition that NovaTel's sample letter had a revocation clause and that its claims were unsubstantiated. The CPUC ordered NovalTel to submit more substantiation for their claim. DRA expects the issue to be resolved in the first half of 2012.

BROADBAND

California Advanced Services Fund (CASF)

In September 2010, DRA requested that the CPUC modify a previous ***California Advanced Services Fund (CASF)*** decision in order to define clear rules for distributing CASF funds. Improved criteria for distribution of these funds would ensure that the CASF program promotes both adoption and affordability of high speed broadband in ***unserved*** and ***underserved*** communities at reasonable rates, in compliance with SB 1040. Subsequently, the CPUC opened a proceeding to implement SB 1040 and to address the concerns raised in DRA's petition.

In April 2011, the CPUC bifurcated the proceeding: Phase 1 addressed implementation issues associated with the Rural and Urban Broadband Consortia Grant Fund; and Phase 2 for all other CASF program issues.

Phase 1 - Grant Applications and their Review Process: DRA advocated for transparency in the application process, implementation of cost-effective projects, and articulation of detailed adoption plans. The CPUC issued a Phase I decision in June 2011 detailing the processes for application filing, selection of eligible consortia, and awarding consortia grants to fund community groups to promote broadband.

Phase 2 - Rules for Infrastructure Revolving Loans and Infrastructure Grants: In August 2011, the CPUC commenced Phase 2 of the proceeding, taking comments on updates to the application requirements and process. DRA advocated for criteria that would require articulated adoption and customer marketing plans, increased transparency for all stakeholders, measurable project outcomes, and accountability for achieving project goals. The CASF program will be successful and in compliance with legislative

WHAT IS IT?

The California Advanced Services Fund (CASF): Established by CPUC decision D.07-12-054, which allocated a $100 million from an existing high cost fund to implement the program, SB 1193 (Padilla, 2008) permitted the use of the High Cost Funds to promote broadband deployment in unserved and underserved areas of California. In September 2010, SB1040 (Padilla), amended PU Code Section 281, extending the CASF for three years and augmenting the fund by an additional $125 million dollars. This legislation extended the life of the program through December 2015 and significantly expanded the program to allow rural consortia to apply for grants. SB1040 also added two new programs: the Broadband Infrastructure Revolving Loan Account and the Broadband Infrastructure Grant Account. Approximately $44.8 million had been awarded by the end of 2011, with $180 million remaining for future CASF projects.

Unserved Areas**:** Areas in California not served by any form of broadband, such that internet connectivity is only available through dial-up service.

Underserved Areas**:** Areas in California served by broadband, but where no facilities-based provider offers service at speeds of at least 3 MBPS download and 1 MBPS upload, which is equivalent to a moderate DSL speed over a conventional copper pair wire.

intent only if grants lead to new *subscribers* (adoption) in unserved and underserved areas. DRA recommended that installation costs must be affordable to customers, rates for service should be capped at their initial affordable rates for at least two years, and start-up costs, including installation fees and equipment such as routers, should be subsidized rather than passing additional costs on to customers.

A CPUC decision implementing CASF Phase II program reforms is expected in early 2012.

CUSTOMER RATES

Foresthill Rate Case

Foresthill is a small local telephone company based in the Sierra foothills, serving approximately 2,800 customers. Like many other small rural telephone companies, Foresthill's revenues are partially subsidized by the ***California High Cost Fund A (CHCF-A)***, as well as federal Universal Service funding. Pursuant to CPUC order, the Basic Service rates have been stable for a number of years and are capped at $20.25 per month. In December 2010, Foresthill requested a total rate base of more than $11 million for 2012.

DRA, instead, recommended a rate base of $9.6 million and proposed that Foresthill not raise any of its other non-capped rates. Based upon its analysis, DRA determined that this could be accomplished without decreasing the current level of service quality provided to Foresthill's customers.

In June 2011, DRA and Foresthill submitted a settlement agreement to the CPUC proposing a rate base of $10.5 million which equates to a 4.94% reduction. In December 2011, the Commission adopted the settlement, but adjusted Foresthill's CHCF-A draw downward to reflect a higher than expected amount of federal universal service funding.

What is it?

California High Cost Fund A (CHCF-A): The CHCF-A is a program which provides supplemental revenues to small rural telephone companies for the purpose of minimizing rate disparities between rural and urban areas. The CHCF-A is funded by a surcharge paid by all telephone customers in California (with some very narrow exceptions). In order for a small telephone company to receive CHCF-A fund subsidies, it must file a General Rate Case with the CPUC so that its costs and rates can be examined to justify it needs the subsidy.

2012 Foresthill Rate Case

	Present Rates	Proposed Rates	Change	Increase/ (Decrease)
Foresthill Request	$ 4,758, 768	$ 6,883,073	$ 2,124,305	44%
DRA Recommendation	$ 4,842,270	$ 4,313,297	$ (528,973)	(10.92%)
Adopted Settlement	$ 4,758,768	$ 5,642,297	$ 883,529	9.4%